JISEA Research Highlight

Integrated Model of Natural Gas Pipelines and the Electricity Grid

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Summary of Findings

This study developed a market-based coordination framework that allows for exchanging information on gas offtakes as well as constraints between gas network and power sector models. The framework—which includes unit commitment and economic dispatch for power plants as well as a dynamic gas network simulation model—was then tested using real power- and gas-system data from Colorado. This study was sponsored by a consortium including Kinder Morgan, Midcontinent Independent System Operator, Hewlett Foundation, Environmental Defense Fund, American Gas Association, and American Electric Power.

Snapshot

- Coordination in forward-looking energy markets (i.e., day-ahead and intra-day) can serve to greatly reduce gas curtailment. For example, the introduction of coordinated intra-day markets (as proposed by FERC Order 809) reduces unserved natural gas by almost 65% relative to uncoordinated operations for the IEEE test system and by almost 97% for the Colorado system.
- For the Colorado system, coordination greatly reduces the amount of curtailed gas power generation without substantial cost increases, particularly in high electricity demand time periods (e.g., summer). This curtailment would otherwise require costly out-of-market intervention by system operators or result in unserved load.
- Coordination between natural gas and power system operations allows for higher renewable penetrations in the power system and reduces natural gas pipeline constraints by increasing total delivered natural gas via redispatch of natural gas power plants.

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The Importance of Coordinated Electricity and Natural Gas Systems

The availability of low-cost natural gas in the United States—driven largely by the shale gas revolution—has driven electric power systems to become more reliant on natural gas. This trend has been amplified by the increasing penetration of renewable energy sources, as natural gas-fired power plants are frequently used to offset the uncertainty and variability associated with wind and solar power generation. In the United States, the power sector accounted for 35.5% of total natural gas demand in 2018, up from just 22.3% in 2000 (U.S. Energy Information Administration [EIA] 2019a, 2019b). The share of generation from natural gas increased from 14.2% to 31.5% over the same period, while the share from renewable energy—largely driven by increases in wind and solar—increased from 8.8% to 17.4%. These trends are expected to persist into the future, as illustrated in Figure 1 (U.S. EIA 2019a, 2019b).

The increasing reliance on natural gas for power system operations poses coordination and reliability challenges. For example, under severe weather conditions both electricity demand and natural gas consumption for heating tend to increase, with fuel shortages leaving gas power plants unable to fulfill their power generation schedules (Saldarriaga-C. and Salazar 2016; Shahidehpour et al. 2005). These conditions entail changes in physical capabilities of pipelines, operational procedures, sensors and communications, and contracting (supply and transportation). Addressing the issue will require increased coordination between the two systems across different decision-making levels, including planning and operations. At the operational level, the objective is to improve reliability and minimize operational costs associated

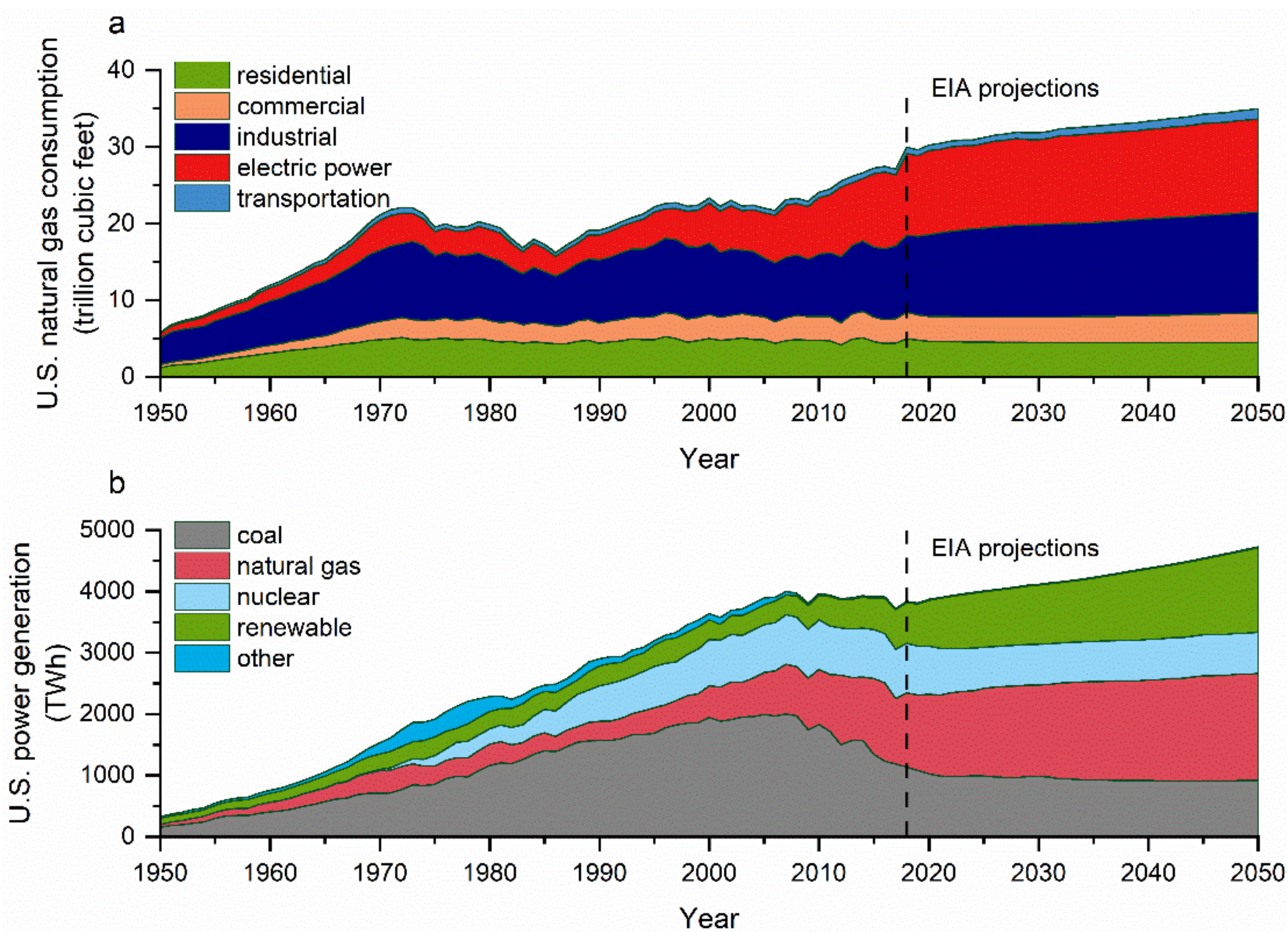

Figure 1. Historical and projected data for natural gas consumption and power generation in the United States: a. Natural gas consumption by sector; b. Power generation by fuel or technology (U.S. EIA 2019a, 2019b).

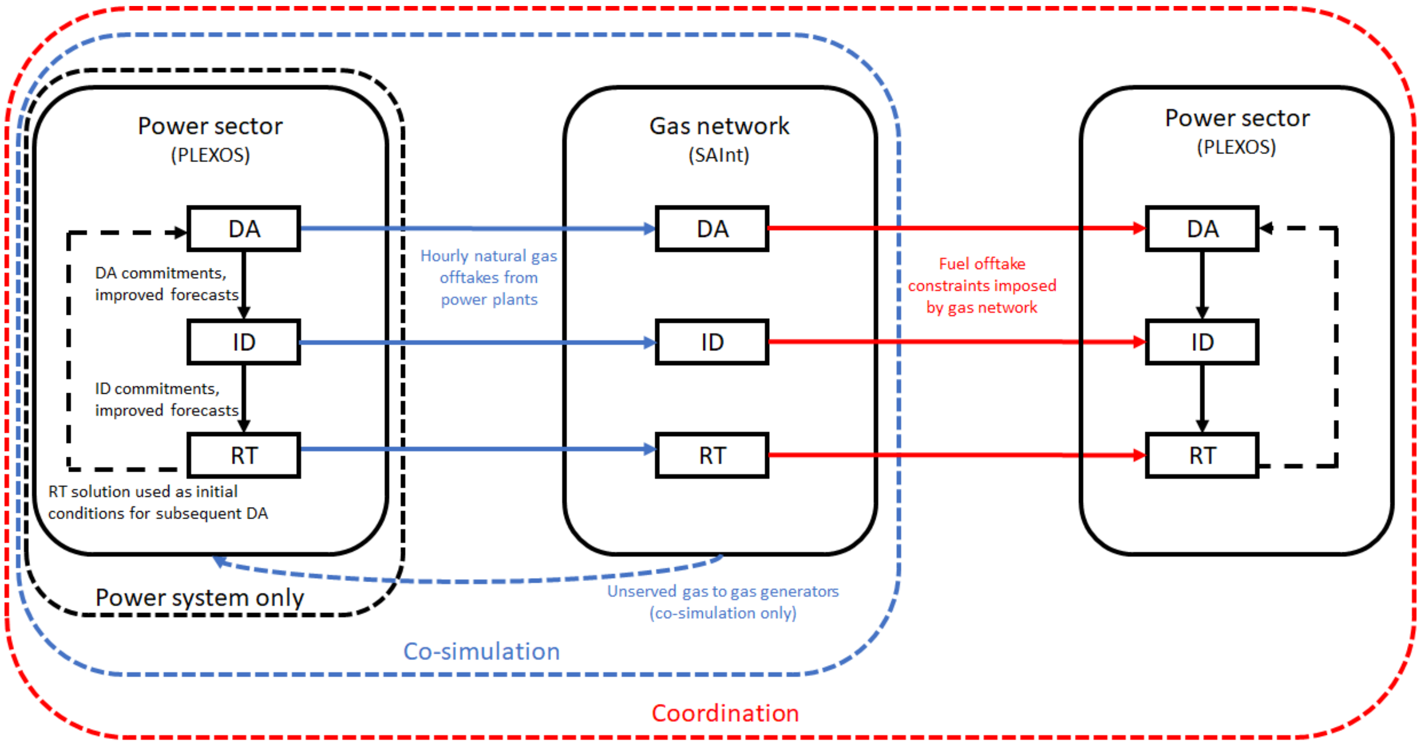

Figure 2. Electricity and natural gas systems coordination framework (implemented in Python). **Power system only**: results from the first iteration of the power system model, before any communication with the gas network. **Co-simulation**: results after simulating gas offtakes from the power system model in the gas network; this reflects curtailed gas but has not yet reoptimized the power system in response to gas constraints. **Coordination**: results after reoptimizing the power system with constraints from the gas simulation.

with natural gas and electricity supply, natural gas supply contracts, and load shedding or unserved natural gas (Chaudry et al. 2008).

This executive report provides an overview of the Natural Gas – Electric Interface Study, which developed and implemented a framework for the market-based coordinated operation of interdependent electricity and natural gas systems. The proposed framework, described in Figure 2, allows for the exchange of information, such as prices, gas demand from generators and gas availability from the gas network, across different timescales—including day-ahead (DA), intra-day (ID), and real-time (RT) markets. This framework was tested using real network and operational data from the Colorado power and gas system, which has been serving Colorado for decades. The study explored a 2018 system and a projected 2026 system to understand how the value of coordination changes in a future scenario with increased renewable generation. The study also quantified the potential benefits of changing how generators submit fuel offtake nominations to the gas network operator.

In most gas systems today, natural gas generators are typically required to submit a steady, nonvarying quantity of gas offtakes for each hour over the course of 24 hours. The use of ratable flows may discourage gas generators from flexible operations because they cannot be guaranteed gas delivery above their ratable flow level and will be subject to risk in the spot market. In contrast, moving to time-variant gas nominations ("shaped flow") at the day-ahead and intra-day market levels has been proposed as a mechanism of improving gas and power sector coordination (Peress and Karas 2017). The value of transitioning from ratable to shaped flow has not yet been studied extensively, particularly for systems with higher renewable penetrations.

Overview of Colorado Power and Gas Systems

Kinder Morgan's Colorado Interstate Gas system has successfully served Colorado for decades. With natural gas a growing fuel source for electricity, there are new complexities associated with load shape and dynamic. In addition, increasing renewables penetration is requiring more natural gas as backup power when wind or solar isn't available. The Colorado gas system has adjusted operations with infrastructure, services, and contracts to successfully meet these varying demands on the pipeline.

The study modeled the Colorado power system using the production cost tool PLEXOS (Energy Exemplar 2019); data for the system was based on a model developed previously for the Western Electricity Coordinating Council (Brinkman et al. 2016). The corresponding Colorado PLEXOS model was representative of the 2018 Colorado electric power grid and included two regions, 1,476 buses, and 1,841 transmission lines, along with just under 21 GW of generating capacity. We used this PLEXOS model to optimize power system operations in the day-ahead, intra-day, and real-time markets. Because the value of coordination is likely to increase with higher penetrations of wind and solar, we also tested our framework on a version of the Colorado system with higher renewable penetrations. To achieve this, we adjusted the installed generation capacity of coal, wind, and solar technologies to represent the projected generation mix in Colorado by 2026 (Overturf and Farnsworth 2020). The corresponding annual generation mix is described in Figure 3,

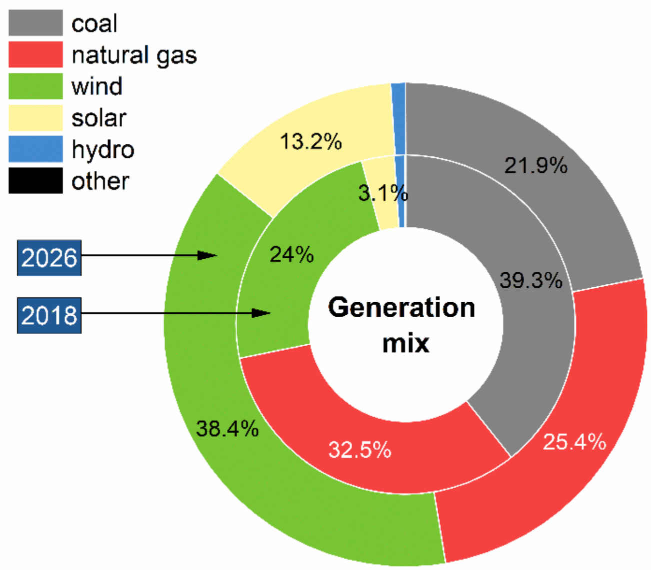

Figure 3. Colorado's generation mix. The 2018 fleet is based on current Colorado fleet, benchmarked to actual generation levels; the 2026 fleet is based on plans developed by Western Resource Advocates to meet Xcel targets (Overturf and Farnsworth 2020). Generation profiles for new wind and solar plants are assumed to be same as the existing plants, with total generation scaled up to match the new capacity.

reflecting increased generation from wind and solar (from 27% to 52%) and reduced generation from coal and natural gas. We assumed that load remains the same in the 2018 and 2026 systems.

We modeled Colorado's natural gas network—which covers most of the Front Range region—using the energy systems integration tool SAInt (encoord 2020). This SAInt model includes details on pipelines, compressors, supply, and offtake nodes; a simplified representation of the network is presented in Figure 4. The offtake nodes include gas generators, representing about 70% of the natural gas generator offtakes in the power system model, as well as information on demand profile for local distribution companies (LDCs). While natural gas generators have interruptible contracts that can be curtailed, LDCs tend to have firm contracts with guaranteed delivery. Data on the minimum delivery pressures for offtake nodes and operating constraints for compressors (e.g., maximum driver power, compression ratio) were accounted for as operational constraints in the gas simulation. We used SAInt to perform a transient hydraulic simulation of operation of the Colorado's natural gas system.

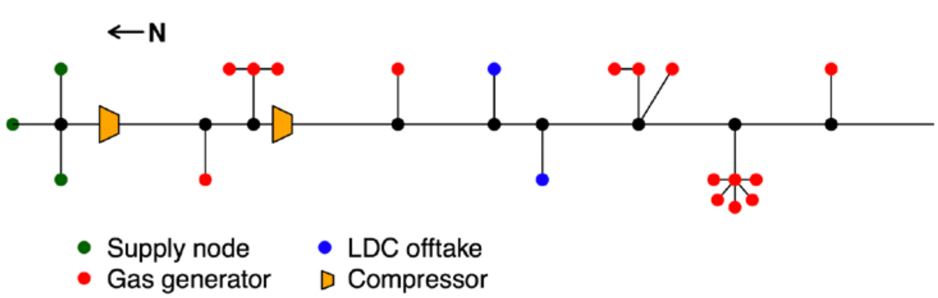

Figure 4. Simplified representation of the gas network in SAInt. Based on data of the Front Range gas network in Colorado.

Streamlined coordination between the natural gas and electric sectors can alleviate many challenges natural gas operators face today with the evolving U.S. power grid. Photo courtesy of Kinder Morgan

Impacts of Coordination on Power and Gas Systems Operations

We used the proposed framework to quantify the value of coordination on Colorado's power and gas systems based on four weeks in 2018 and 2026. We selected one week from each season (spring, summer, fall, and winter) in which the natural gas demand from the power sector is highest, as these weeks are likely to be the times when coordination between the two systems is critical. The selected weeks include June 2–8 (spring), July 14–20 (summer), November

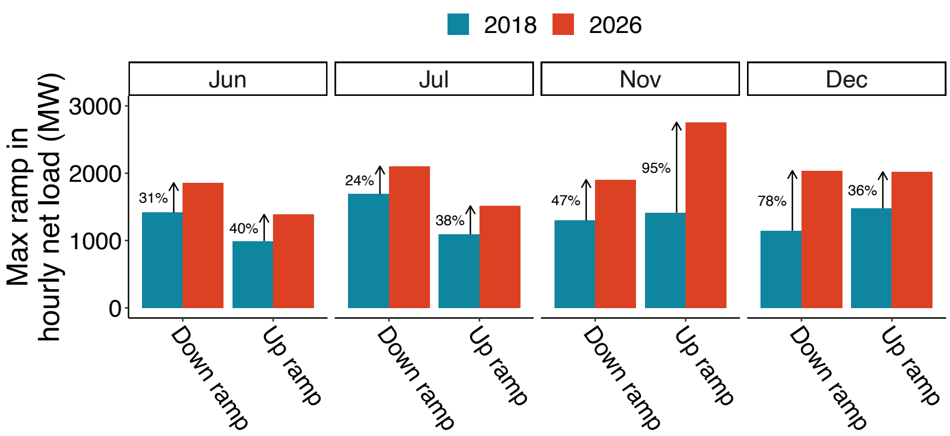

Figure 5. Largest up and down ramps in net load (MW) in 2018 and 2026; ramping requirements increased in the 2026 scenario with the increased reliance on generation from wind and solar.

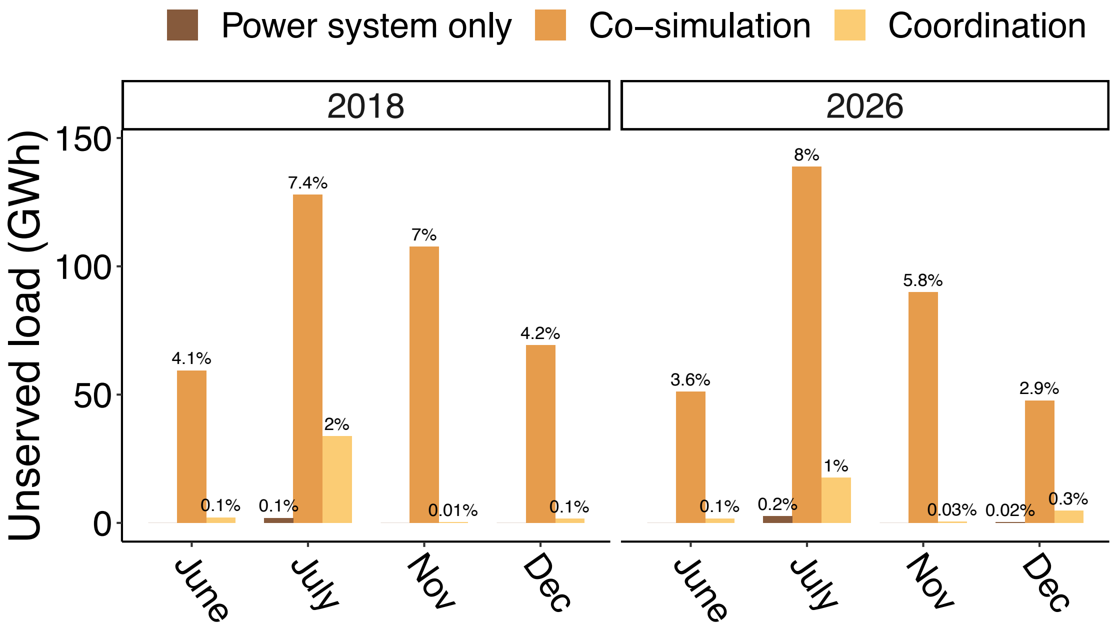

Figure 6. Total unserved load, or generation that cannot be delivered by gas generators, by week, year, and coordination scenario (power system only, co-simulation, and coordination). Numbers indicate unserved load as a percentage of total load that week. Results are shown for scenarios using ratable flows at the day-ahead and intra-day levels but are similar with shaped flows. Unserved load in this context can also be thought of as the amount of power system operators would need to obtain through out-of-market, manual interventions.

17–23 (fall), and December 12–18 (winter). Note that higher penetration of renewables in 2026 resulted in greater ramping requirements (see Figure. 5); these higher ramping requirements could be better accommodated with coordinated system operations.

Impacts on Unserved Electricity Load

Total unserved load by week, year, and coordination scenario is summarized in Figure 6. There is virtually no unserved energy in the initial power system optimization (power system only); however, when gas curtailments are imposed from constraints in the gas network (co-simulation), large amounts of unserved load occur, ranging from 2.9%–8% of the total weekly load. This represents generation that cannot be delivered by gas generators and would either need to be left unserved or rectified using potentially costly out-of-market interventions by the system operator. If the power system is re-optimized based on input from the gas network (coordination), the amount of gas curtailment and unserved load is substantially reduced. Although unserved load after redispatch is still higher than the unconstrained initial dispatch, the initial dispatch is operationally infeasible given the constraints from the gas network. With the exception of the summer week (July), unserved electricity load tends to be higher in 2018 relative to 2026. This reflects the higher penetration of renewable generation in 2026, which reduces the total gas demand from the power system.

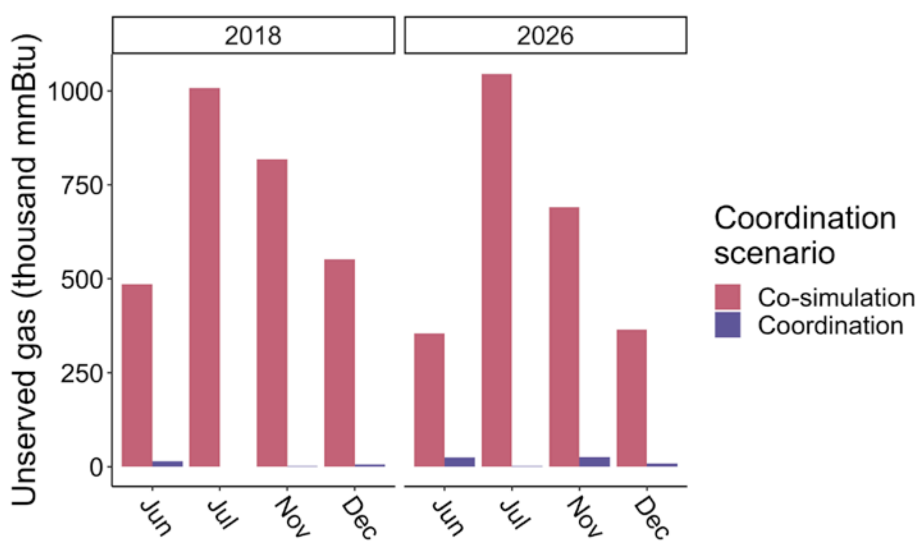

Figure 7. Total unserved natural gas (in thousand mmBtu) by week for the co-simulation and coordination scenarios; results are shown using ratable flows.

Better coordination between electricity and natural gas systems can facilitate higher renewable penetrations. Photo from iStock 498769592

Impacts on Unserved Gas Demand

The change in total unserved natural gas demand between the co-simulation and coordination scenario for each week and year modeled is illustrated in Figure 7. The plot shows total unserved gas in the co-simulation scenario is highest in July—when demand is highest—but is relatively evenly split across the weeks modeled. Redispatch of the power sector based on constraints from the gas model (i.e., coordination) serves to reduce unserved gas by upwards of 97% relative to co-simulation. After accounting for changes to gas consumption based on redispatch, total delivered natural gas increases by approximately 4.4% with coordination.[1] If natural gas prices are $2.5/mmBtu, this increase in delivered gas would represent an additional $1.7 million in revenue for the entities responsible for delivering natural gas for these four weeks ($1 million using a gas price of $1.5/mmBtu and $3.3 million with a price of $5/mmBtu).

The Value of Shaped Flow Gas Nominations

The effects of shaped flow gas nominations on unserved gas demand for the day-ahead and intra-day markets are summarized in Figure. 8. At the co-simulation level, ratable flows result in about 4% more unserved gas in 2018 and comparable amounts in 2026. After accounting for redispatch, moving to shaped flows can provide an additional $0.6 million in revenues for the four weeks modeled at gas prices of $5 per mmBtu ($0.4–0.9 at prices of $3–7 per mmBtu) in the 2018 case, even before coordination. Although total unserved gas is greatly reduced by coordination, using ratable flows

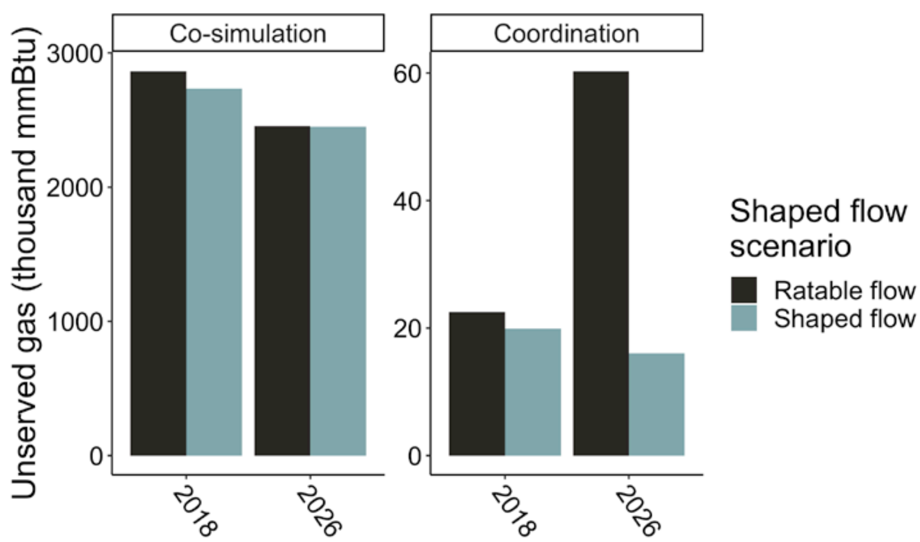

Figure 8. Total unserved natural gas (in thousand mmBtu) when using constant flows at the day-ahead and intra-day market levels (ratable) or when allowing hourly gas offtakes from generators (shaped flow). Both scenarios allow hourly offtakes at the real-time market levels. Note the difference in y-axes across panels.

1 This estimate includes both generators within the gas network as well as generators that are in the power system but outside the gas network. Although dispatch from out-of-network generators increases with coordination, total offtakes from these plants typically represents less than 30% of all offtakes.

after coordination results in almost three times more unserved gas in the 2026 case. This is likely due to the fact that the higher penetration of renewables in 2026 results in greater ramping requirements, with down ramps increasing by 24%–78% from 2018 to 2016 and up ramps increasing by 36%–95%, depending on the week of analysis. These higher ramping requirements are better accommodated when more temporally granular offtake nominations are passed to the gas network in the forward-looking day-ahead and intra-day markets. Moving to shaped flows earns $0.2–0.5 million in additional revenue for the four weeks studied after coordination in the 2026 case.

Conclusion

This study explored the benefits of coordinating power system and natural gas networks using data from real systems in Colorado. The results show that coordination can reduce the quantity of unserved natural gas to generators, alleviating the need for potentially costly out-of-merit operator interventions. Allowing greater flexibility in the nominations sent by generators to the gas network can also serve to cut down gas curtailments, particularly in future systems with high penetrations of renewables in which flexibility from gas generators is needed. Coordination between electricity and natural gas markets and, in particular, the use of time-variant shaped-flows may help plan for and alleviate the stresses associated with ramping requirements for systems with high penetrations of renewables. The framework developed in the study provides a template for future work to explore the linkages between electricity and natural gas networks, and for examining the value of coordinating these two increasingly interdependent systems.

Learn More

See the NREL technical report on this work titled "Electric Power Grid and Natural Gas Network Operations and Coordination," by Omar J. Guerra, Brian Sergi, Michael Craig, Kwabena Addo Pambour, Rostand Tresor Sopgwi, Carlo Brancucci, and Bri-Mathias Hodge. **https://www.nrel.gov/docs/fy20osti/77096.pdf** Also see the journal article "Natural Gas-Electric Interface Study," by Omar J. Guerra, Brian Sergi, Michael Craig, Kwabena Addo Pambour, Carlo Brancucci, Bri-Mathias Hodge. **https://doi.org/10.3390/en11071628**

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