The Hidden Flexibility of the Natural Gas Network for Electric Power Operations: A Case Study of a Near-Miss Winter Event

Andrew Fay,[1] Getnet Ayele,[1] Carlo Brancucci,[1]
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List of Acronyms

ERCOT	Electric Reliability Council of Texas
HELICS	Hierarchical Engine for Large-scale Infrastructure Co-Simulation
LDC	local distribution company
NREL	National Renewable Energy Laboratory
SAInt	Scenario Analysis Interface for Energy Systems
VOM	variable operation and maintenance

Executive Summary

The U.S. power sector has become increasingly reliant on gas pipeline networks to deliver fuel to natural gas power plants, coupling the operation of the power system with those of the corresponding gas networks. An advantage of this intercoupling is that gas networks offer electric generators operational flexibility through the ability to deliver fuel when needed by using gas storage facilities or linepack—the natural gas stored within pipelines—if the gas network is at an operating point below its design capacity. However, disruptions or stress events on the gas network—like those occurring in the Northeast in January 2014 and Texas in February 2021—can result in limitations on gas availability to generators when generation is in short supply.

Here we examine a period of cold temperatures resulting in high gas demand and high electric load and coinciding with a drop in wind generation. To address these conditions, the power system operator dispatched more gas generation than anticipated, which the gas network operator supported through flexibility in reducing its gas deliveries to interconnected pipelines who agreed to these reductions in delivery.

Using data on the region's natural gas pipeline network and electric generators, we build an integrated gas and electric model that closely replicates the actual dispatch of the period. We then evaluate the implications of removing flexibility employed by the gas network operator, which during that period, reduced gas deliveries to other parties to increase deliveries to natural gas power plants, which requested more gas than initially forecasted.

We find that without the flexibility supplied by the gas network operator, there would have been reductions in gas power plant dispatch due to gas offtake constraints. This reduction would have required the power system operator to redispatch from its gas generators, and thus potentially needing to call on more-expensive generation or even to shed load. A sensitivity exploring a wind drought further exacerbates the strain, illustrating the potential challenge of managing gas and grid interactions as systems move to higher shares of variable renewable electricity. Based on this example, we discuss potential strategies for coordination between the two system operators to ensure the power system can successfully utilize and rely on the flexibility offered by natural gas networks.

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Introduction

The U.S. power system is more coupled with the gas pipeline network than it has been at any point in its history. In 2021, natural gas generators supplied approximately 37% of total annual generation, up from around 16% 20 years ago (U.S. Energy Information Administration 2023b). As the share of generation from natural gas has increased, so too has the role of the power sector as a recipient of natural gas from the perspective of gas network operators. In 2001, purchases of natural gas by the power sector amounted to 24% of total gas sales; by 2021, that figure had increased to just over 36% (U.S. Energy Information Administration 2023b).

Although other thermal power plants, such coal and nuclear plants, typically store fuel on site, most natural gas generators receive their fuel via pipeline delivery in real time. In addition, gas power plants are often committed in real time or ramped up or down to respond to fluctuations in load, other generating resources with variable output (such as wind and solar), or outage events on the network. As a result, the amount of gas extracted by gas power plants from the pipeline network can vary substantially over the course of days or even hours. Historically, natural gas network operators have been able to support this variability by storing excess gas at storage facilities or within the pipelines themselves; this storage is referred to as linepack. By storing extra gas for variable operations at gas generators, the gas network in essence acts as a hidden source of flexibility to the power system. The amount of flexibility the gas network can provide depends on the network's configuration, including the location of any gas storage, the length and diameter of the pipelines, generator ratings, and the demand for gas from other users.

During normal operations, natural gas generators will ramp up or down, relying on the flexibility of the natural gas system to deliver gas when generators request it. However, this flexibility may be unavailable during times of stress. For example, the cold temperatures associated with a polar vortex in 2014 in the Northeast led to higher demand for natural gas from other sectors, namely residential heating. As a result, some gas-fired generators on interruptible contracts were unable to procure fuel and thus could not be dispatched (North American Electric Reliability Corporation 2014).

Likewise, a major winter storm in February 2021 caused a protracted period of load shedding in Texas. Although there were many drivers of the shortfall, including inoperable generating facilities of all types because of the cold weather, one contributor was a lack of natural gas supply due to frozen gas wellheads and electricity disruptions at gas extraction and network points (Energy Institute 2021). The Texas power system operator (the Electric Reliability Council of Texas, or ERCOT) estimated that during the hour of highest outages, as much as 6 GW of generation—approximately 12% of the total outages at the time—was offline due to an inability to obtain natural gas supplies (ERCOT 2021). Although weather-related disruptions at natural gas plants (e.g., plant equipment freezing) were responsible for most of the outages, the 12% of outages related to fuel-starvation exacerbated the shortfall during this critical period.

In this study, we explore gas network and electric power system interactions during a period of stress. During this period, the gas network operator reduced gas deliveries to mutually agreeable interconnected parties (other parties) to increase deliveries to natural gas power plants, which consumed more gas than initially forecasted. By deploying these measures, the gas network operator was able to provide extra flexibility to the electric system operator. For the case study reported here, we use data on the natural gas pipeline network and electric generators of the region to build an integrated gas and electric model that closely replicates the actual dispatch of the period. We then evaluate the implications of removing the flexibility employed by the gas network operator. The case study illustrates the importance of the hidden flexibility the gas network can provide and thus highlights the importance of coordination between the gas and power system operators to ensure this flexibility can be fully utilized.

Case Study Overview

In this case study, a weather front moved through the area resulting in a significant decrease in air temperatures that persisted for several days. The colder temperatures led to higher gas demand for heat-dependent loads, such as the residential and commercial customer loads. The cold temperatures were accompanied by a large drop in wind generation and an unexpected increase in electric demand, as the day-ahead forecast underestimated the actual load. Figure 1 shows the temperature and actual generation levels for the study area during this period of six days.

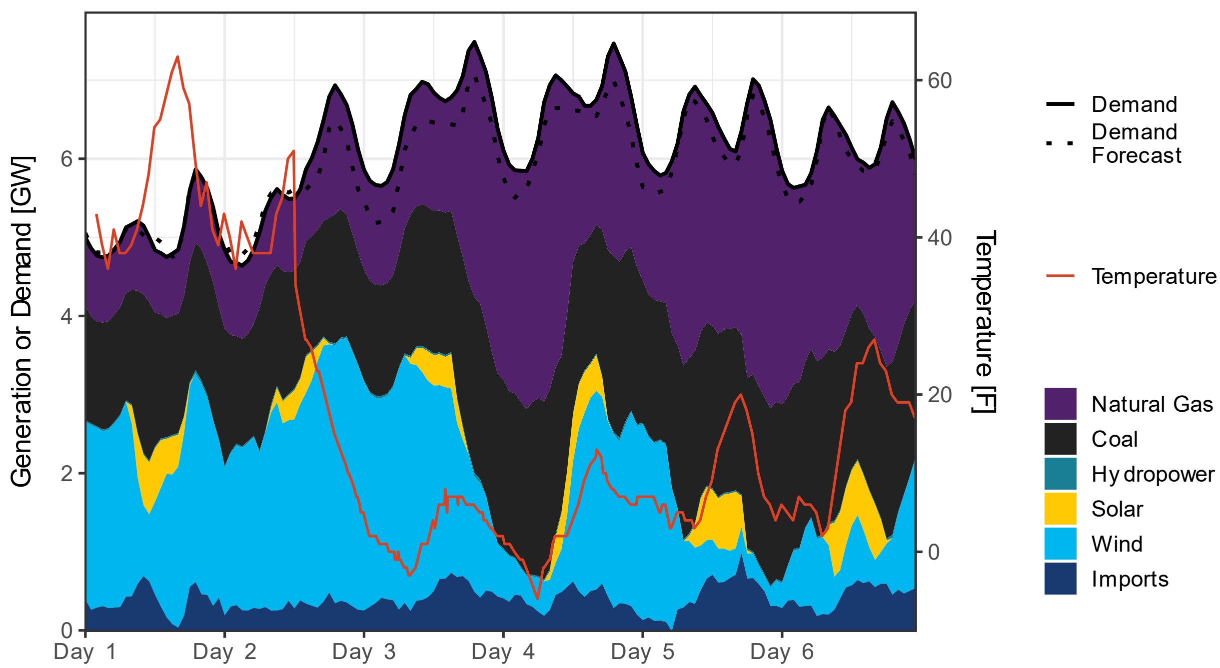

Figure 1. Temperature, electric load, and generation from select sources for the study area

The combination of these conditions necessitated a large increase in gas-fired generation over what was initially forecasted, as seen in Figure 1 starting in the evening of Day 3. The increased generation requirements from the gas-fired power plants compelled the gas network operator to reduce gas deliveries to other parties to ensure deliveries to both the gas-fired power plants and the local distribution company (LDC), which delivers gas to other customers.

In this case study, we explore what might have occurred if the gas network operator had been unable to exercise the flexibility with interconnected pipeline deliveries to supply the gas-fired generators. To answer this question, we build a coupled model of the electric and gas pipeline networks in the study area and simulate the period in question under a range of conditions. The coupled model used in this analysis was developed and implemented in the Scenario Analysis Interface (SAInt), a commercial modeling software by encoord (encoord 2023). This integrated planning software allows for coordinated modeling of electric power and natural gas networks. The rest of this section details the simulation models and the scenarios analyzed.

The electric network is represented in this analysis using an optimal unit commitment and economic dispatch model. This model is based on data from the U.S. Energy Information Administration (EIA). Generator information comes from EIA Form 860 (U.S. Energy Information Administration) and time series data—including electric demand, wind and solar generation, and imports from other neighboring regions—come from EIA's Hourly Electric Grid Monitor (U.S. Energy Information Administration 2023a). The model uses 24-hour optimizations with hourly time steps and a 24-hour look-ahead. For this case study, adjustments were made to the variable operational costs of generators to mimic the real-life dispatch by generation technology as published by the EIA. Also, the model factored in known plant outages. Figure 2 shows the dispatch plot for this system without considering any gas-fired generation curtailment due to gas network constraints.

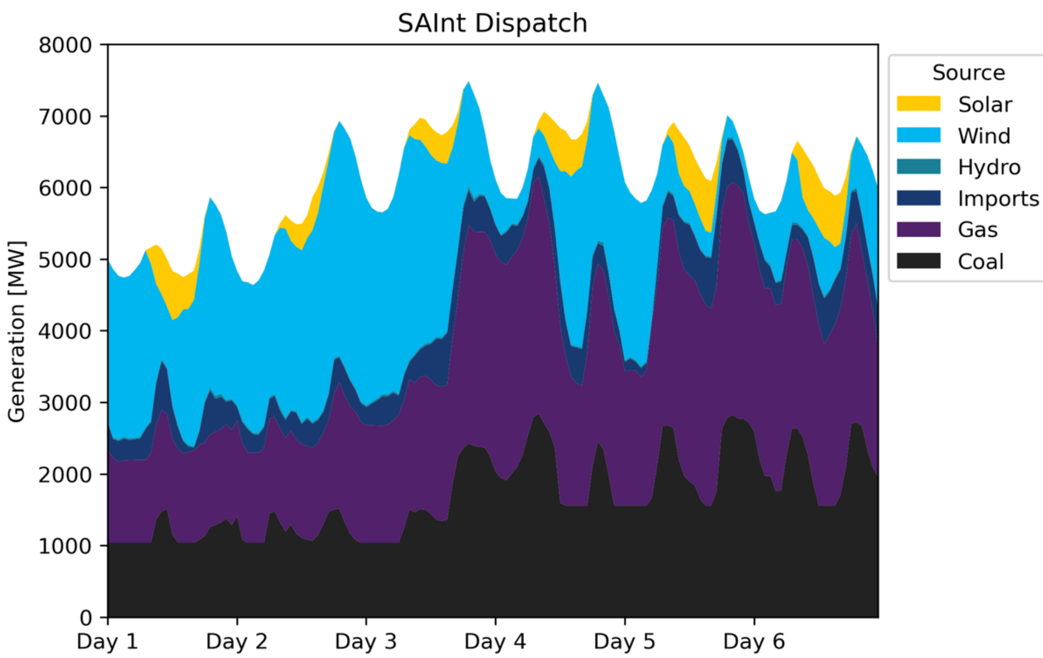

Figure 2. Dispatch by generator type during the study period using the SAInt model

The gas model is a time-varying, transient, hydraulic model with information provided by the gas network operator. The system comprises 230 nodes, 190 pipeline sections, and 37 isolation valves. Gas supplies and receipts come from gas processing plants, underground storage facilities, and commercial trading hubs. Interconnect deliveries to this network include LDC, gas-fired power plants, and commercial trading hubs. The gas subsequently moves through facilities along the pipeline route from producer to end users. The gas network operating boundaries are constrained by maximum receipts pressure and minimum delivery pressure. In addition, the supply gas flow was limited by the amount of intraday and day-ahead scheduled gas for the period.

The gas network hydraulic simulation uses hourly time steps, which matches the time steps of the electric unit commitment and economic dispatch optimization model. The gas network serves gas-fired generation, the gas LDC, and deliveries to other pipeline systems. Only a portion of the gas-fired generation in the electric dispatch model is linked to the gas model. Approximately 44% of the installed gas-fired electric generation capacity is directly linked to the gas model. The remainder of the gas-fired generation, which is referenced here as "other gas generation" is not directly served by this gas network operator and is not included in the analysis.

The gas network operator monitors and measures gas flow rate, temperature, and pressure throughout the pipeline network. During this event, the system operator observed higher heating loads from the LDCs and significant offtakes from power plants due to ramping. This resulted in a loss of pressure, which the system operator responded to by reducing flows to non-LDC and power plant demands.

To model the coordination between the gas and electric system operators, the approach used in this analysis iterates between the electric and gas models. First, the electric model is solved for optimal commitment and dispatch without any input or constraints from the gas model. The results from the electric model include the natural gas fuel requirements for all generators. These fuel requirements are then used as the requested demand in the gas model at the corresponding offtake location of the gas-fired generators.

The gas hydraulic model is then solved and identifies any gas delivery or pressure-driven constraints. These constraints result in differences between the fuel requirements from the electric model and the fuel available in the gas model. These differences are the unserved gas demands. The available fuel from the gas model is used as a constraint and enforced on the electric unit commitment and dispatch model, which is then solved again. The results of this new simulation are compared to the first in terms of operational costs, dispatch, and unserved electric demand, if there is any.

To understand the role of flexibility in the gas network, we simulate a scenario in which the gas network operator can no longer reduce deliveries to other parties. In addition, we consider another scenario in which the low wind generation levels are assumed to persist longer than they originally occurred. Figure 3 shows the original wind generation profile versus the adjusted wind profile. For each scenario, we evaluate the generation (dispatch), the amount of unserved electricity or gas demand, and operational costs for the electricity system.

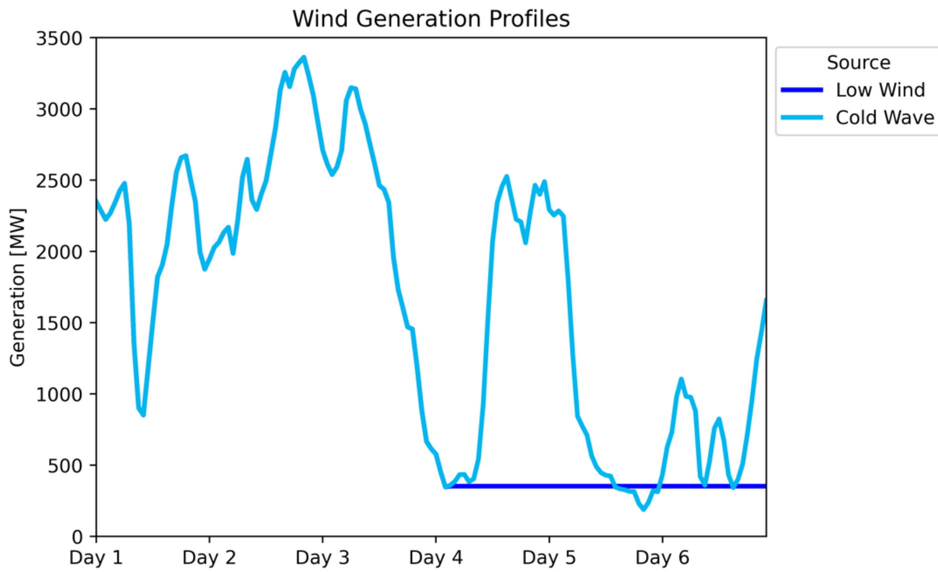

Figure 3. Wind profiles in the study area during the event ("Cold Wave") and for a hypothetical low wind scenario ("Low Wind")

Findings

Cold Wave Scenarios

The Cold Wave scenarios mimic the electric dispatch for this period using the wind, solar, and import data from the power system operator. The Cold Wave with Flexibility scenario relies on the ability of the gas network operator to make operational adjustments in order to provide the required deliveries to the gas-fired power plants. The flexibility provided by these adjustments by the gas network operator include reduction of gas deliveries to other parties. This scenario approximates what actually occurred during the event.

To evaluate what might have happened if the gas network operator had been unable to utilize the flexibility to meet gas power plant demands, we compare the first case to a second, Cold Wave without Flexibility scenario. In this case, the gas network is evaluated assuming the gas network operator was unable to reduce the gas deliveries to other parties. Because of this limitation, gas deliveries to the LDC and gas-fired power plants must be curtailed to sustain the minimum delivery pressures, which leads to unserved gas demand. This gas scenario was developed to attempt to prioritize the LDC deliveries over the gas-fired power plants.

The tables and figures below describe the results and summarize the impacts of this loss of flexibility on the gas system. The Cold Wave with Flexibility scenario is the dispatch without the consideration of constraints within the gas network, and Cold Wave without Flexibility scenario considers the impacts of the gas network constraints.

The dispatch of each case is shown in Figure 4. It shows an increase in coal generation for the scenario without flexibility compared to the scenario with flexibility. The increase in coal generation compensated for the decrease in gas-fired generation due to gas network constraints. The electric network has enough available generation capacity to meet all the demand.

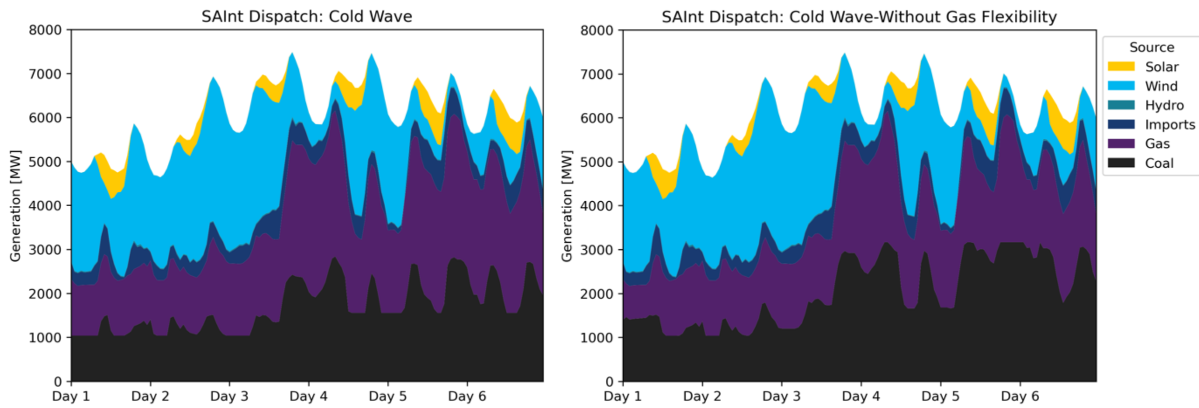

Figure 4. Cold wave dispatch with and without flexibility

In the absence of gas network flexibility, the necessary redispatch results in total increased operational costs of $422,000. This is an increase of approximately 2.7% of total operational costs over the 6-day period. The unserved gas offtake and reduction in output of those gas-fired generators forces the more expensive generators to turn on, which drives up the overall operational costs. Most of the additional costs are incurred in the last few days. This is the period of highest stress on the gas network, and it results in the largest gas reduction.

The combination of gas output reduction along with high electric demand and the highest fossil generation, from natural gas and coal, results in the operational cost increases. Table 1 and Table 2 show the total operating costs by type for each day. Most of the costs are associated with fuel costs, with fuel costs comprising over 80% of total costs in the Cold Wave case. A comparison of operational costs for each case is shown in Table 3.

A comparison of the operational costs for each case shows an overall cost increase as the gas-fired generation is reduced. Table 3 shows this comparison of operational cost by type. There is an increase in start-up and variable operation and maintenance (VOM) costs, of $193,000 and $367,000 respectively, and a decrease in fuel costs of $138,000, for a total increase of $422,000 for the 6-day period.

Table 1. Operational Costs by Type: Cold Wave with Flexibility

All results are in units of $1,000.

Date	Start-Up Costs	Fuel Costs	VOM Costs	Total
Day 1	3	1,291	280	1,574
Day 2	43	1,408	299	1,750
Day 3	230	2,006	412	2,648
Day 4	58	2,563	538	3,159
Day 5	30	2,624	554	3,209
Day 6	5	2,529	535	3,070
Total	**370**	**12,422**	**2,618**	**15,410**

Table 2. Operational Costs by Type: Cold Wave without Flexibility

All results are in units of $1,000.

Date	Start-Up Costs	Fuel Costs	VOM Costs	Total
Day 1	52	1,267	302	1,621
Day 2	76	1,408	306	1,790
Day 3	230	1,956	469	2,656
Day 4	28	2,511	608	3,148
Day 5	96	2,656	667	3,420
Day 6	80	2,485	633	3,198
Total	**563**	**12,284**	**2,985**	**15,831**

Table 3. Change in Operational Costs without Gas Network Flexibility: Cold Wave

Results show change in costs from Flexibility to No Flexibility case. All results are in units of $1,000.

Date	Start-Up Costs	Fuel Costs	VOM Costs	Total	Difference (%)
Day 1	49	-24	22	47	3.0%
Day 2	33	-1	7	39	2.2%
Day 3	0	-50	57	7	0.3%
Day 4	-30	-51	70	-11	-0.4%
Day 5	67	32	113	211	6.6%
Day 6	74	-44	97	128	4.2%
Total	**193**	**-138**	**367**	**422**	**2.7%**

Without considering the gas network, the dispatched generators from the Cold Wave with Flexibility case have the lowest operational costs. The dispatched generators in Cold Wave with Flexibility case have higher fuel costs but lower start-up and VOM costs than the offline generators.

Without the flexibility provided from the gas network, the requested natural gas deliveries are constrained and are unable to be fulfilled. In the Cold Wave without Flexibility scenario, these constraints force the electric network to pivot and depend on the more expensive generation assets. A portion of these operating gas-fired generators must turn off in the Cold Wave without Flexibility case due to the restrictions in the gas network.

As generators turn down or off due to the reduction in gas in the hypothetical, Cold Wave without Flexibility scenario, additional generators are required to cover the loss in gas-fired generation. These additional generation requirements force different generators to turn on, which increases the costs associated with start-ups. These newly active coal and other gas-fired generators have lower fuel costs but higher operating costs than the Cold Wave with Flexibility case, which leads to the overall increase in operational costs for the period. Coal generation increases, especially during the last days of the period, where it hits its maximum limit of the available coal generation capacity.

The overall decrease in fuel costs is a result of an increase in coal costs with a decrease in natural gas costs for each day in the period. These results of the fuel cost comparisons are detailed in Table 4.

Table 4. Fuel Costs Comparison: Cold Wave

Results show change in costs from Flexibility to No Flexibility case. All results are in units of $1,000.

Date	Gas	Coal	Total
Day 1	-88	63	-24
Day 2	-23	22	-1
Day 3	-222	172	-50
Day 4	-251	199	-51
Day 5	-249	281	32
Day 6	-311	267	-44
Total	**-1,143**	**1,005**	**-138**

Figure 5 and Figure 6 are dispatch plots by generation source comparing the Cold Wave with Flexibility scenario to the Cold Wave without Flexibility scenario.

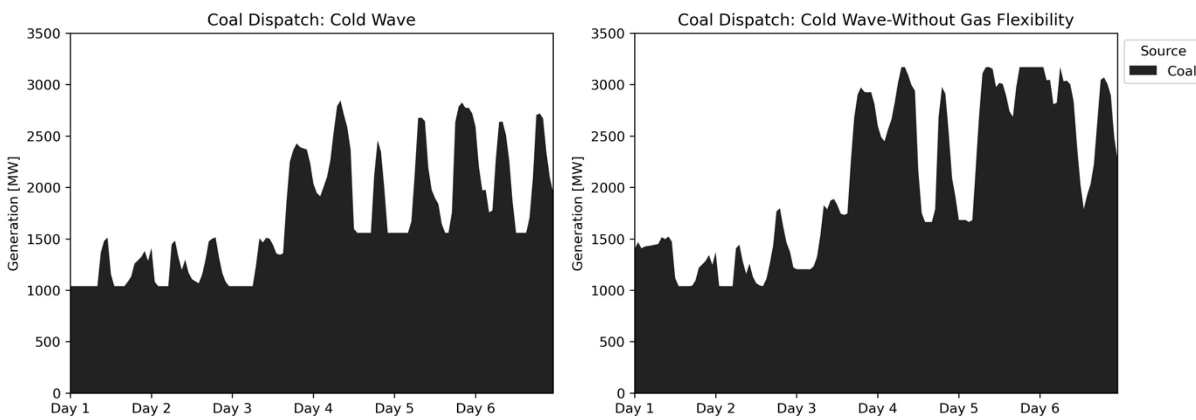

Figure 5. Coal dispatch with and without flexibility in the Low wind scenario

Figure 6 shows the dispatch of gas-fired generation by gas pipeline network source (i.e., whether the gas generators are connected to the gas network that we model or are considered "Other" gas generators connected to a different gas pipeline network). These other gas-fired generators are not directly served by the gas network modeled in this study and therefore, these generators are not impacted by gas network constraints. Electricity generation from gas-fired power plants included in the gas model decreases and the other gas-fired generation increases when the flexibility is removed. It is important to note that this assumes the gas network supporting the "Other" gas generators can deliver sufficient fuel. In many instances, regional weather patterns result in constraints across multiple networks simultaneously, which could in practice limit the ability to utilize neighboring networks during stress periods.

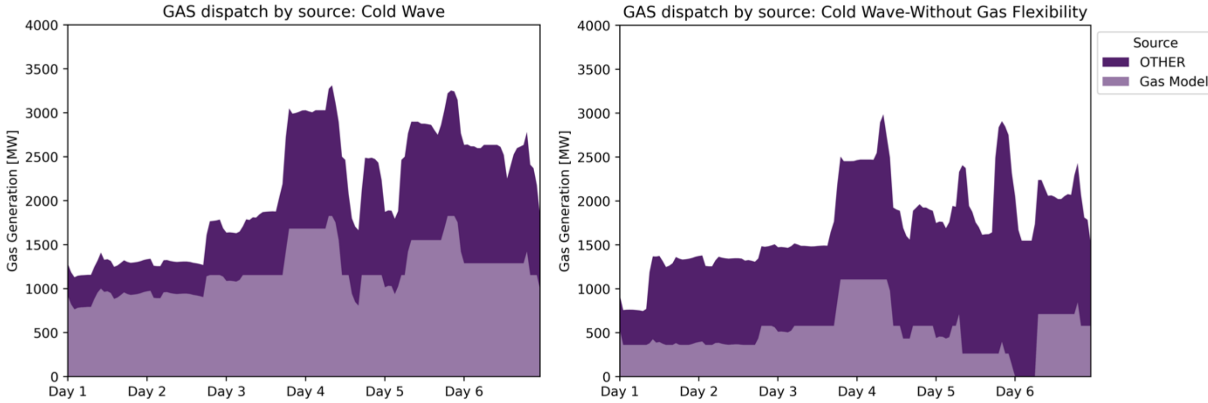

Figure 6. Cold wave gas dispatch by source versus without flexibility

Low Wind Scenarios

As an alternative to the Cold Wave scenarios, the Low Wind scenarios were developed that extended the drought in wind generation. On the fourth day in this scenario, the wind generation is held constant at approximately 350 MW for the remainder of the period. The wind generation profiles are the same up to this point on the fourth day. This lower wind generation scenario results in a total reduction in wind by approximately 20% over the 6-day period.
As in the Cold Wave cases, the Low Wind with Flexibility scenario relies on the flexibility provided by the gas network operator, whereas the Low Wind without Flexibility scenario evaluates the effects of removing this flexibility supplied by the gas network operator on the electric dispatch for the Low Wind scenario. In this case, the gas network is evaluated assuming the gas network operator was unable to reduce the gas deliveries to other parties. Because of this limitation, gas deliveries to the LDC and gas-fired power plants were reduced to sustain the minimum delivery pressures, leading to unserved gas demand. This gas scenario is again developed to prioritize the LDC deliveries over the gas-fired power plants.

The tables and figures below describe the results and summarize the impacts of this loss of flexibility on the gas system. The Low Wind with Flexibility scenario is the dispatch (without the consideration of constraints within the gas network), and Low Wind without Flexibility scenario considers the impacts of the gas network constraints.

The dispatch of each case is shown in Figure 7. It shows an increase in coal generation for the scenario without Flexibility, compared to the scenario with Flexibility. The increase in coal generation compensated for the decrease in gas-fired generation due to gas network constraints. The electric network has enough available generation capacity to meet all the demand.

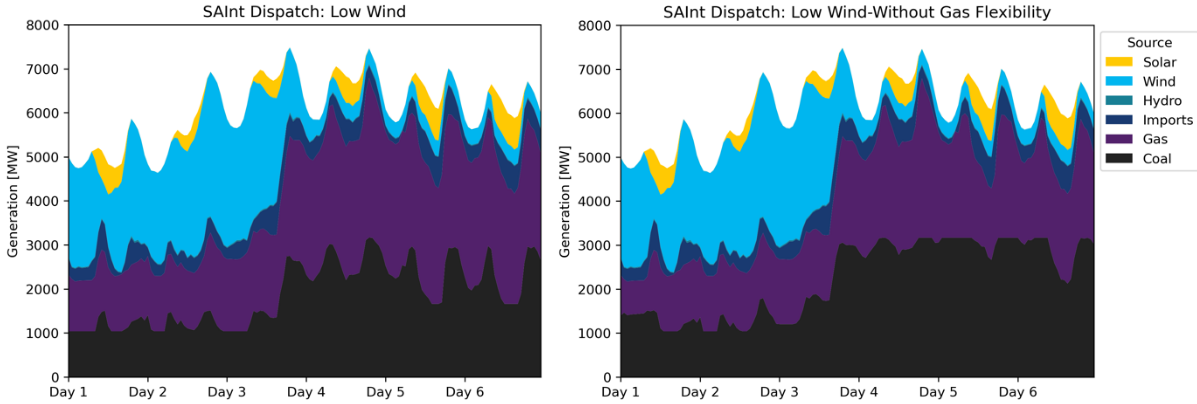

Figure 7. Low wind model dispatch versus without flexibility

However, the required redispatch results in total increased operational costs of $698,000. This is an increase of approximately 4.2% of total operational costs over the 6-day period. The unserved gas offtake and curtailment of those gas-fired generators forces the more expensive generators to turn on which drives up the overall system costs. Most of the additional costs are incurred in the last few days, especially considering the extended low wind generation during the same period. This is the period of highest stress on the gas network that results in the largest gas curtailment. The combination of curtailment along with high electric demand, the extended low generation from wind, and the highest fossil generation, from natural gas and coal, results in the operational cost increases greater than those seen in the Cold Wave scenario without Flexibility. Table 5 and Table 6 show the total operational costs by type for each day, with most of the cost associated with fuel, over 80% in the Low Wind case.

Table 5. Operational Costs by Type: Low Wind with Flexibility

All results are in units of $1,000.

Date	Start-Up Costs	Fuel Costs	VOM Costs	Total
Day 1	3	1,291	280	1,574
Day 2	43	1,408	299	1,750
Day 3	273	1,998	418	2,689
Day 4	75	3,087	691	3,853
Day 5	0	2,907	635	3,542
Day 6	1	2,755	594	3,349
Total	**395**	**13,446**	**2,917**	**16,758**

Table 6. Operational Costs by Type: Low Wind without Flexibility

All results are in units of $1,000.

Date	Start-Up Costs	Fuel Costs	VOM Costs	Total
Day 1	52	1,267	302	1,621
Day 2	76	1,408	305	1,789
Day 3	231	1,969	471	2,670
Day 4	84	3,104	763	3,950
Day 5	71	3,019	774	3,864
Day 6	107	2,752	703	3,562
Total	**620**	**13,519**	**3,317**	**17,456**

Comparing the operational costs for each case in the Low Wind scenario shows an overall cost increase as the gas-fired generation is curtailed. Table 7 shows this comparison of operational cost by type across the two scenarios. There is an increase in start-up, fuel, and VOM costs, of $225,000, $73,000, and $367,000 respectively, for a total increase of $698,000 for the 6-day period.

Table 7. Change in Operational Costs without Gas Network Flexibility: Low Wind

Results show change in costs from Flexibility to No Flexibility case. All results are in units of $1,000.

Date	Start-Up Costs	Fuel Costs	VOM Costs	Total	Difference (%)
Day 1	49	-24	22	47	3.0%
Day 2	33	0	6	39	2.2%
Day 3	-42	-29	52	-20	-0.7%
Day 4	8	17	72	97	2.5%
Day 5	71	112	139	322	9.1%
Day 6	106	-3	109	212	6.3%
Total	**225**	**73**	**400**	**698**	**4.2%**

The dispatched generators from the Low Wind with Flexibility case, have the lowest operational costs without considering the gas network. The dispatched generators in Low Wind with Flexibility case generally have higher fuel costs but lower start-up and VOM costs than the offline generators.

Without the flexibility provided from the gas network, the requested natural gas deliveries are constrained and are unable to be fulfilled. In the Low Wind with Flexibility scenario, these constraints force the electric network to pivot and depend on the more expensive generation assets. A portion of these operating gas-fired generators must turn off in the Low Wind without Flexibility case due to the restrictions in the gas network.

As generators turn down or off due to the gas curtailment, additional generators are required to cover the loss in gas-fired generation. These additional generation requirements force different generators to turn on which increases the costs associated with start-ups. These newly active coal and other gas-fired generators have lower fuel costs but higher operating costs than the Low Wind with Flexibility case which led to the overall increase in operational costs for the period. Coal generation increases, especially during the last days of the period, where it hits its maximum limit of the available coal generation capacity more and overall is dispatched at a higher level than in the Cold Wave without Flexibility scenario.

The overall increase in fuel costs is a result of an increase in coal costs with a decrease in natural gas costs for each day in the period. These results of the fuel cost comparisons are detailed in Table 8.

Table 8. Fuel Costs Comparison: Low Wind

Results show change in costs from Flexibility to No Flexibility case. All results are in units of $1,000.

Date	Gas	Coal	Total
Day 1	-86	62	-24
Day 2	-20	20	0
Day 3	-178	149	-29
Day 4	-149	166	17
Day 5	-212	324	112
Day 6	-282	279	-3
Total	**-926**	**999**	**73**

Figure 8 and Figure 9 are dispatch plots by generation source comparing the Low Wind with Flexibility to the Low Wind without Flexibility.

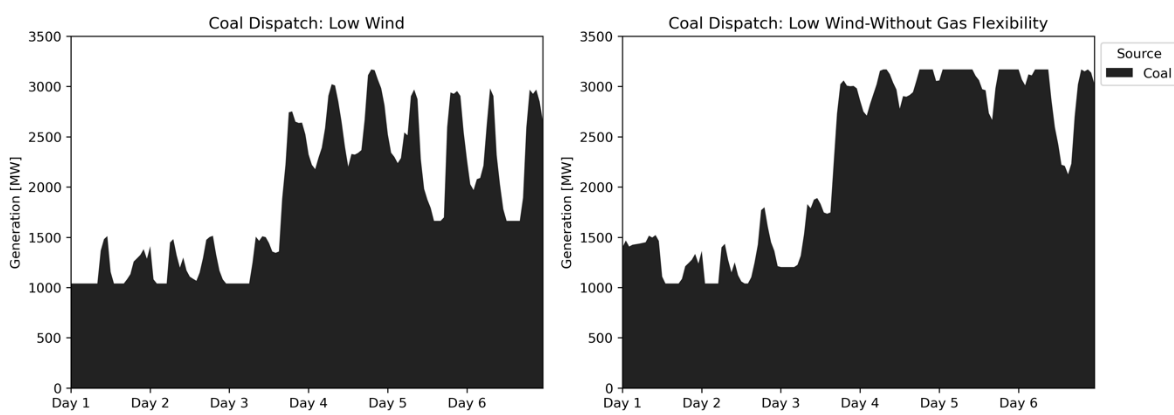

Figure 8. Coal dispatch with and without flexibility in the Low wind scenario

Figure 9 shows the dispatch of gas-fired generation by gas pipeline network source (i.e., whether the gas generators are connected to the gas network that we model or are considered “Other” gas generators connected to a different gas pipeline network). These other gas-fired generators are not directly served by the gas network modeled in this study, and these generators are therefore not impacted by gas network constraints. Electricity generation from gas-fired power plants included in the gas model decreases, while the other gas-fired generation increases compared to when the flexibility is removed.

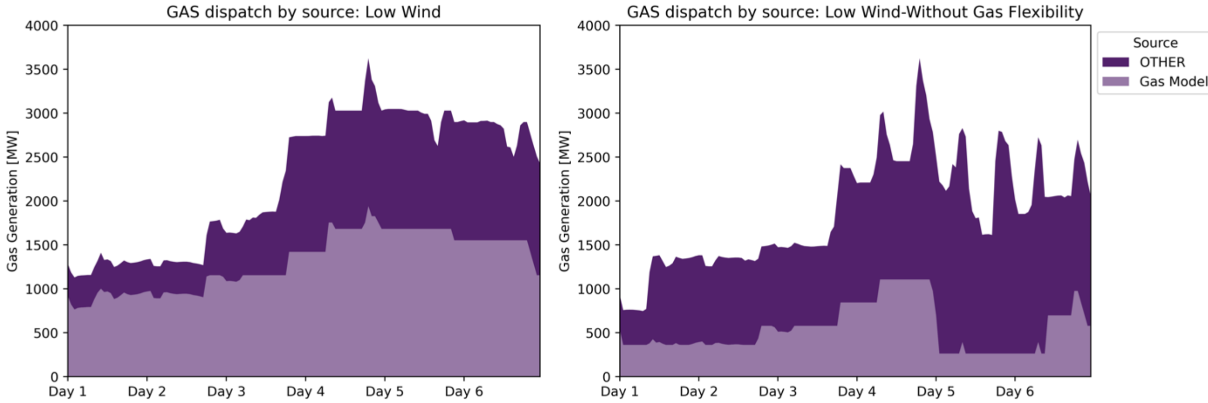

Figure 9. Low wind gas dispatch by source with and without flexibility

"OTHER" comprises natural gas plants that are not in the gas network operator's footprint; accordingly, gas deliveries at these plants are not subject to the network constraints of the modeled plants.

Discussion

The interaction between the electric power and gas networks is often seamless and therefore unremarkable, and in many instances, power system operators successfully leverage the flexibility provided by gas networks. However, winter storm events or other stress periods can expose the potential pitfalls of relying on this hidden flexibility without careful planning.

In this case study, we rely on real system data to model a recent winter stress event. Unlike the Texas winter storm or other well publicized cold weather events, the event evaluated in this study did not result in shed load or generator outages. However, these outcomes were avoided because the gas network operator was able to respond to the event and flexibly reallocate gas deliveries to meet higher demand from gas generators.

In this instance, the gas network operator was successful in reallocating gas deliveries to avoid major outages and meet the higher demand from the gas generators. The modeling in this study illustrates that without this flexibility supplied by the gas network operator there would have been curtailment of gas generation due to gas network constraints. As a result, the power system operator would have been required to dispatch more expensive generation sources. Although in this example, generation capacity was sufficient to meet electric demand in all scenarios, this kind of situation could potentially lead to electric load being shed, particularly since generator outages are often correlated (Murphy et al. 2018).

This "near-miss" scenario provides an important reminder of the need for electric power system operators to better understand the flexibility offered by gas networks, and to coordinate with gas system operators to maximize the use of this flexibility and to mitigate risks during stress periods. This need is likely to increase in the near term to medium term as power systems move to retire thermal power plants and replace them with higher levels of wind and solar while continuing to rely on natural gas for balancing, as the variability of wind and solar is likely to drive increased ramping of gas-fired generators and increased uncertainty in generation levels.

There is a range of potential options for improving coordination between electric power system and gas network operations. A partial list of potential approaches includes the following:

- **Improved Forecasting:** In this case study, the gas network operator was forced to intervene because of unexpected ramping of gas-fired generators. This includes not only forecasting of temperature and gas demand by LDCs, but also forecasts of wind and solar availability because their absence may, for many systems, imply greater need for gas generation. More-robust forecasting of future gas and electric load demand may also help both system operators adequately prepare for stress events.
- **Changes to Gas Nominations:** Nominations, or the amount of gas requested for delivery, are typically submitted by gas-fired power operators in advance (e.g., a day ahead or in some cases several days ahead) and on a ratable basis (i.e., averaged over a 24-hour period). Moving to hourly or subhourly nominations may allow for (1) better capturing of the actual dynamics of gas usage of gas-fired power plants and (2) the gas network operator to plan around those dynamics (Peress and Karas 2017; Guerra-Fernandez et al. 2020). More-regular updates to nominations, such as on over weekends (typically nominations submitted Friday are used for Saturday to Monday) may help provide more up-to-date operational information. Intraday nominations may also help, but the flexibility they bring is limited because they only apply to remaining hours in the day.
- **Firm contracts**: Many gas-fired power plants have natural gas interruptible contracts, given their variable operation. On the other hand, LDCs generally have firm contracts. In situations of stress where the gas network operator can't meet all its customers' needs, firm contracts have priority over interruptible contracts. Firm contracts could be costly for gas-fired power plants but would potentially justify additional gas infrastructure investments that would enhance the natural gas network's ability to meet the variable and uncertain demand of gas-fired power plants. Firm contracts, however, may not be sufficient or the ideal solution, given the current nomination cycles and the extreme ramping behavior of some gas-fired power plants in response to large electric net demand changes.
- **Coordinated Gas Storage:** Coordinated investment and operation of gas storage could help gas network operator respond to variable and uncertain operations by gas-fired generators. This option is more expensive than relying on interruptible contracts for just-in-time delivery and thus would require a willingness to pay for additional resilience or flexible operations. In addition, gas storage—which is typically in depleted gas fields—may not always be available in the parts of the network nearest to gas-fired generators.
- **Coordinated Power System Investments:** Just as coordinated investments in gas network flexibility can enhance the interaction between the two networks, additional power system flexibility may similarly reduce instances in which one network constrains the other. For example, investments in energy storage or transmission may help provide additional flexibility that may offset some of the need to ramp natural gas plants, and thus reduce the need for rapid changes in natural gas offtakes.

Going forward, continued modeling of the coupling points between these two systems is critical to understanding their interactions and to ensure both systems continue to operate reliably.

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