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How vulnerable are US natural gas pipelines to electric outages?

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ABSTRACT

Gas-electric interdependencies have contributed to several major electric system emergencies. Natural gas pipelines use both gas-powered and electric-powered compressor units; power outages at the latter can cause gas shortages. We make the first rigorous identification of the number of US electric compressor stations, finding that 10% are electric. California, the Midwest, the Gulf Coast, and the East have high installed electric compressor capacity. New hydraulic models, verified by past events, show that disrupting power to a single compressor station can force a loss greater than 2 GW of downstream gas generators. Such an outage can be larger than the most severe single-cause failure currently considered in electric reliability planning. Electric utilities should immediately incorporate the identified facilities into critical facility lists. Establishing a federal gas reliability organization, comparable to what is now done for electric power, could improve gas reliability by establishing appropriate reliability reporting, incident investigation, and minimum industry standards.

1. Introduction

Natural gas supplies 32% of all primary energy in the US. Its share of electricity generation nearly doubled from 21% in 2008 to 38% in 2021 (EIA, 2022a). Gas-electric interdependencies have contributed to several major electric system emergencies due to gas shortages at times of high electric load, including the Texas 2021 event that led to over 200 deaths (Busby et al., 2021; FERC et al., 2021; FERC and NERC, 2019, 2011; NERC, 2014). The North American Electric Reliability Corporation (NERC) has declared addressing gas-electric interdependency risks a top priority requiring immediate attention (NERC, 2022). Electrically powered compressor stations on natural gas transmission lines have been mentioned as a possible contributor to these gas shortages (FERC and NERC, 2011; Hibbard and Schatzki, 2012; Judson, 2013; Portante et al., 2017), though they have attracted little rigorous public analysis. Electrically-dependent stations are vulnerable to electric outages during these events, and their loss could cause downstream losses of gas-fired electric generators. However, due in part to the lack of regulatory oversight of the gas transmission system (Freeman et al., 2018), the extent of reliance on electric compressors and the potential consequences of failure are not well understood. Here, we investigate the vulnerability of electric power generation to electric outages at pipeline compressor stations across the US.

Compressor stations are spaced every 50–100 miles along pipelines to overcome frictional losses (Mohitpour et al., 2007; Myles et al., 2017). These stations usually have multiple compressor units, each powered by a driver such as a gas turbine, a gas reciprocating engine, or an electric motor (Myles et al., 2017). It is common industry practice for compressor stations to have enough on-site backup power to serve auxiliary demands such as control systems, lighting, and cooling fans (Figure A1 in Appendix A) (FERC et al., 2021). However, electrically-driven compressor loads are usually too large (as high as 60 MW) for practical on-site backup (Hitachi Energy, 2021). An electric outage to a compressor station, therefore, has the potential to take all on-site electric compressor units out of service. Electric outages are relatively common (EIA, 2021a; Haes Alhelou et al., 2019; Jufri et al., 2019), with even large outage events over 300 MW occurring on average more than once a month in the US (Hines et al., 2009) and over 10 GW every 11 years (Carreras et al., 2016). Winter storms are a leading cause of widespread electric outages (Mukherjee et al., 2018), a particular problem given that colder temperatures also lead to higher gas demand.

Outages to electric compressor units can cause gas shortages unless

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lost compressor power is replaced by redundant gas units at the same station or stations immediately downstream; otherwise, the outage requires downstream flow reductions to maintain adequate pressures (Mohitpour et al., 2007). During times of high gas demand, such redundancy may not exist. Unlike the electric system, there are no regulated redundancy requirements in gas transmission (FERC and NERC, 2019). Only some pipeline systems are designed with redundancy for individual compressor units (NERC, 2011), and even that would be insufficient to mitigate risks from a single electric outage to multiple units at the same or nearby stations.

There have been various calls to rigorously identify gas-electric system vulnerabilities (Freeman et al., 2018, 2020; Hibbard and Schatzki, 2012; Judson, 2013; NASEM, 2021; NERC, 2017, 2013, 2011). Much of the gas-electric interdependency literature focuses on the dependence of gas power plants on gas deliveries (FERC et al., 2021; FERC and NERC, 2019, 2011; Freeman et al., 2021, 2020; Levitan & Associates, 2015; NERC, 2014; Portante et al., 2017). There has been less attention on the dependence of the gas system on electricity, despite the possible negative feedback loop this creates. Gas supply decreases caused by the dependence of the gas system on electricity have been partially quantified at gas wellheads and processing facilities for two events in Texas (FERC et al., 2021; FERC and NERC, 2011). However, investigators made no direct connections from production decreases to gas generator fuel shortages, likely due to the difficulty in modeling interactions between gas supply, transmission, and storage, as well as the resulting pressure and line pack fluctuations across multiple transmission pipeline operators. Further, while several gas-electric emergencies have resulted in rigorous investigations over the past decade, no quantitative estimates of generator outages due to issues with gas transmission have been made (FERC et al., 2021; FERC and NERC, 2019, 2011; NERC, 2014). Therefore, improving characterizations of the gas transmission system is required to understand the cause of gas shortages to power plants from the entire gas system.

Identifying electric compressor stations to prevent gas-electric outages has been recommended following previous gas-electric interdependency events (FERC and NERC, 2019). Regulators saw this as particularly important given perceived increases in electric station installations attributed to concerns about air emissions in populated areas associated with gas-powered compressor stations (FERC and NERC, 2011). One grey literature report used Homeland Infrastructure Foundation-Level Data (HIFLD) data to classify electric stations, but substantially overestimated electric dependence as they were unable to account for the inconsistent reporting of auxiliary electricity consumption with only one year of data available (HIFLD, 2022; Myles et al., 2017). More importantly, the report erroneously concludes that a compressor station outage is unlikely to affect downstream gas power plant operations; however, this conclusion relies on an unrepresentative hypothetical pipeline system that does not allow for consideration of effects far enough downstream and improperly applies rules of thumb meant for normal operation to upset conditions.

Another study estimated that the gas transmission system could provide fuel to national defense installations for two weeks upon complete failure of the bulk electric system, but assumes sharply reduced gas consumption for electric generation and space heating due to the electric outages and therefore has limited relevance for assessing the reliability for those two societally critical gas end uses (Judson, 2013).

Industry has also paid insufficient attention to this issue, for example, the otherwise detailed Eastern Interconnection's Gas-Electric System Interface Study specifically excludes consideration of electric compressors (Levitan & Associates, 2015). As a sign of improvement, following Winter Storm Uri investigators identified outages to seven electric compressor stations and gas storage facilities in Texas (FERC et al., 2021). However, they did not determine the consequence of these outages, leaving their relative contribution unknown to the 27% of electric generator outages caused by gas shortages.

Here we significantly improve our understanding of the dependence of the gas transmission system on electricity by providing a systematic accounting of US interstate pipeline compressor stations that use electric drivers and are therefore dependent on electricity. By estimating the magnitude of gas shortages resulting from electric outages to these stations using industry-standard hydraulic modeling, we also show that these outages are much more significant than previously understood. We find that in Florida, electric compressor unit outages at a single station have the potential to force gas generator outages of magnitude larger than that of losing a 1.08 GW nuclear unit, the largest generator outage planning contingency in Florida. We also find that in the 2014 polar vortex (NERC, 2014), an electric compressor station outage was the largest single cause of generator outages.

2. How many US compressor stations rely on the electric grid?

We identify compressor stations with electric drivers by assessing historical station-level operating hours, gas consumption, and electricity consumption (Hitachi Energy, 2021). If annual electricity consumption and operating hours are correlated, and electricity use is in line with the installed power at the station, we conclude that it has an electric driver and is vulnerable to electric outages. Otherwise, the reported electricity use is likely attributable to only auxiliary system demands generally having on-site backup.

2.1. Electric station identification method

Compressor station data were obtained from Velocity Suite (Hitachi Energy, 2021), as collated from FERC Form 2 Sheets 508–509 (FERC, 2022). The data contain 70 interstate gas pipeline systems with annual transportation or storage capacities over 50 million dekatherms. After cleaning duplicates and decommissioned units, the number of stations or identifiable substations is reduced to 1449. Data on 35 additional stations from California intrastate pipelines, as described separately in Appendix A, brings the total number of stations or substations to 1484. Data are available from 2008 to 2020, with 2008 being the first year electricity consumption is reported. The data includes annual compressor station-level reporting on installed brakepower capacity, number of units, operating hours, gas consumption, and electricity consumption.

The 1449 interstate stations and substations are separated into driver types: gas, electric, mixed (gas & electric), and unclear. First, the 1449 stations are separated into those that report only gas consumption (1057 stations), only electricity consumption (45), both (302), or do not report fuel consumption (45). Those that consume only one energy type are designated as having only that driver type (gas or electric). Next, the 302 stations that use both gas and electricity are examined further to determine whether they have a single driver type or have units with a mixture of driver types. As FERC Form 2 reporting instructions are not explicit on whether auxiliary system consumption of gas and electricity should be reported, small amounts of one fuel consumption may be attributable to auxiliary system use. Therefore, we assess the annual historical data for both fuel types based on two criteria: (1) Is the amount of fuel consumption large enough to indicate a transmission-sized compressor driver on-site, given the available station nameplate capacity? (2) Is the fuel use correlated to operating hours at the station?

To answer these questions, we created two graphs for each station, showing both electricity and gas consumption by operating hours. Graphs for three example compressor stations of each type are shown in Fig. 1, with additional examples in Appendix A. Each of the 302 stations reporting both gas and electricity use was assessed using figures created similar to Fig. 1 and designated as being gas-driven, electrically-driven, or having mixed drivers. To consider question 1, we create benchmark trendlines of the anticipated amount of energy consumption based on station characteristics. Generally, energy consumption can be related to operating hours using the driver power and efficiency ratings per the equation below. Trendline slopes have units of power. In the case of

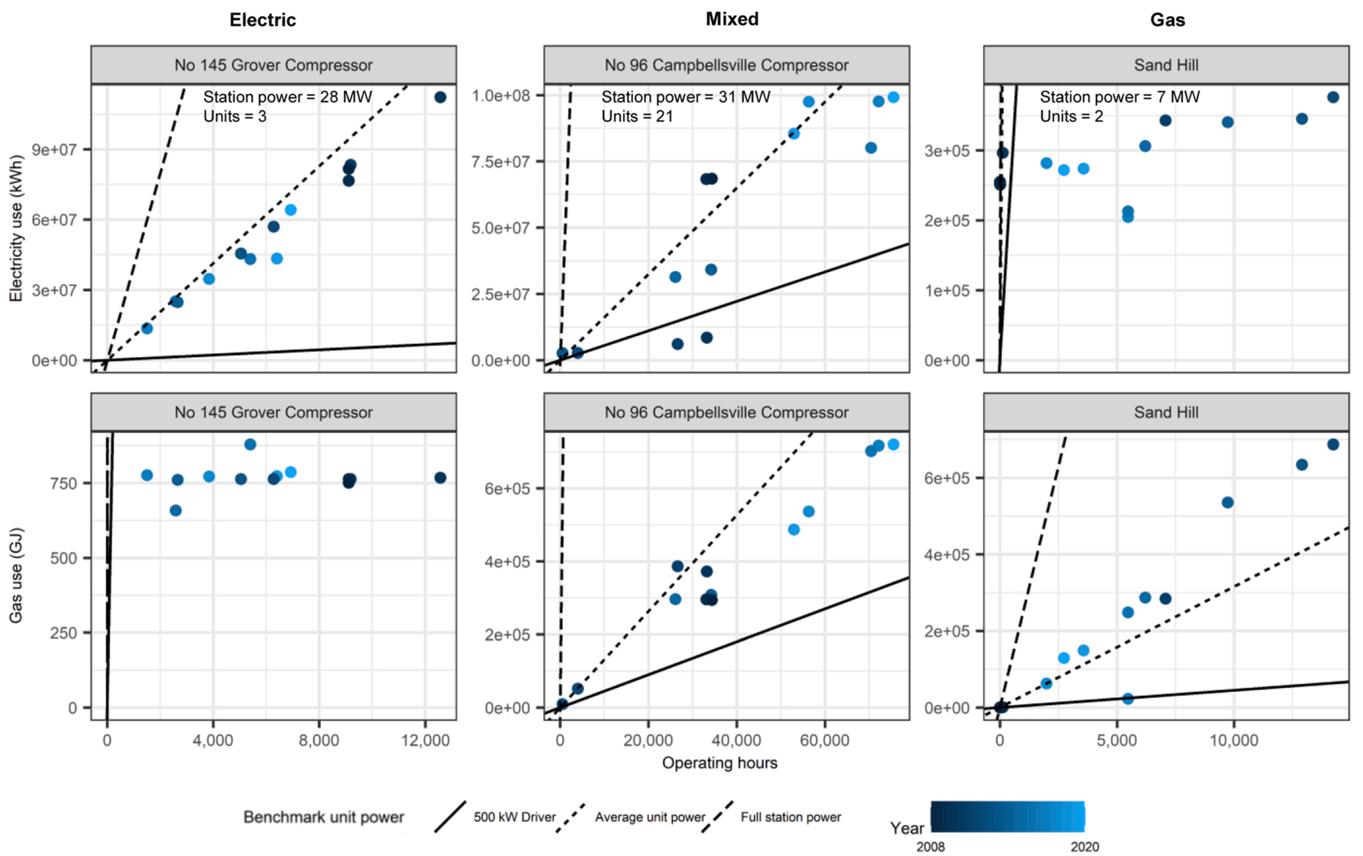

Fig. 1. Annual electricity (top) and gas (bottom) consumption for three representative compressor stations. From left to right, stations are determined to be electric drive, mixed drive, and gas drive. The black lines are energy consumption benchmarks considering typical compressor driver efficiencies based on the total station power (long dash), the station's average unit power (short dash), and a 500 kW brakepower unit (solid). The station on the left is assessed to be electric because electricity consumption is very close to the expected consumption calculated from the station's average unit power benchmark and is highly correlated with operating hours; on the other hand, historical station gas use is so low the energy consumption benchmarks appear nearly vertical. For the station assessed to be gas (right), the opposite patterns are observed. For the mixed drive station with both gas and electric drivers, the assessment is based on relatively high use of both gas and electricity and a moderate correlation to operating hours for both fuels.

electricity use, this can be illustrated by dividing the y-axis units (kWh) by the x-axis units (hours), indicating trendline units of kilowatts. Since the data are available at a station-level rather than unit-level, for stations with more than one unit this equation cannot be estimated precisely, as the specific unit power and efficiency related to a given operating hour are unknown. However, in practice we observe that benchmark trendlines for indicative energy consumption given the station power, number of units, and typical driver efficiencies are sufficient in the vast majority of cases to identify the station driver.

$$Energy\ consumption = \frac{Driver\ brakepower}{Driver\ efficiency} * \ Operating\ hours$$

Driver efficiencies are chosen based on current manufacturer reported nominal efficiencies then derated to reflect differences across equipment age and size and the variation across equipment operating ranges (ABB, 2021; ANSI/NEMA, 2021; "Solar Turbines, 2022). We used electric driver efficiencies of 70–90% and gas driver efficiencies of 10–40%. A high bound trendline is set by dividing the total station brakepower by the low-efficiency values. For stations with more than one unit, this will overestimate energy consumption as the reported operating hours are a total from all units (i.e., a two-unit station may report up to 17,520 operating hours in a non-leap year). Therefore, a best estimate unit average power benchmark trendline is calculated by dividing the total station brakepower by the number of units and the driver high-efficiency values. While a best estimate, individual unit power can vary significantly between units at a station, so the observed historical data trend may have slopes higher or lower than this unit average. Finally, a lower bound trendline is determined using a unit power of 500 kW and high driver efficiencies. A power of 500 kW is selected as very low for a single unit driver at a transmission compressor station but high for typical compressor auxiliary energy demand. Reported station power and units from 2020 are used. We note that the benchmark lines are much more sensitive to variations in station brakepower, which varies by four orders of magnitude, than the assumed range of driver efficiencies.

For validation, unit-level descriptions were obtained from station air permits (Florida Department of Environmental Protection, n.d.) for seven Florida Gas Transmission Company compressors designated as both gas and mixed. By comparing the number of units and capacity between the gas units listed on the air permit and the station totals from the Velocity Suite data (Hitachi Energy, 2021), we confirmed that the method accurately categorized these station types. Further, spot checks of other pipeline systems using Google Earth satellite imagery show that stations classified as electric or mixed have on-site electric substations, while stations classified as gas do not.

2.2. Electric drivers are installed at 10% of compressor stations on key pipelines

Approximately 10% of US stations have electric drivers and are dependent on electricity, with 7% having all-electric drivers and 3% having a mixture of individual units driven by gas or electricity (Table 1). By nameplate power, 9% are all-electric and 7% are a mixture of gas and electric, indicating that electrically dependent stations on

Table 1
Compressor station fuel type summary table for US interstate gas pipeline systems. While the fraction of electrically powered compressors is modest, many are in key locations, and there is evidence that their numbers are growing.

Metric	Gas	Electric	Mixed	Unclear/ No Data	Total
Number of stations	1273 (86%)	98 (7%)	51 (3%)	62 (4%)	1484 (100%)
Nameplate capacity (MW)	14,810 (83%)	1552 (9%)	1213 (7%)	266 (1%)	17,841 (100%)

average have more installed nameplate power than gas stations. The 4% of stations that do not report sufficient historical data or whose trends are unclear represent only 1% of installed nameplate power, suggesting that most are lower capacity stations. A list of Electric, Mixed, and Unclear stations is available in Appendix B, with locations organized by electric service territory, NERC region, and ISO.

We determined assessment confidence levels for each station given the degree to which energy consumption of each fuel type was within the expected boundaries and the correlation of energy consumption to operating hours. As indicated in Table A1, 90% of stations are classified with high confidence, and 95% are classified with at least medium confidence. Of the remainder, 3% of stations have no reported fuel consumption data on which to make a determination. Figures A2 to A4 in Appendix A show additional station classification graphs similar to Fig. 1.

While our analysis focuses on the US, we note that electrically-driven gas compressor stations also exist in Canada (Smillie, 2019), Norway (Kozyaruk and Vasil'ev, 2013), Germany (Vasiliev and Mardashov, 2019), and France (Alas and Noulette, 2013). These aggregate findings indicate higher electric dependence in the US than more granular Canadian compressor unit-level data, in which 6% of units and 4.5% of unit power are from electric drivers (Smillie, 2019).

We find considerably fewer electrically-dependent compressors than the previous analysis that did not account for auxiliary electricity and gas consumption, which found that 23% of stations depend on electricity (6% electric, 17% mixed gas/electric) (Myles et al., 2017).

Fig. 2 is a map of electrically dependent compressor stations and pipeline systems. Systems with higher numbers of electrically-dependent compressor stations are shown in yellow. Electrically-dependent compressor stations tend to be concentrated on particular pipeline systems and in particular regions. California, the Gulf Coast, and the East as far north as Pennsylvania have the highest installed capacities of electric compression (Figure A5 of Appendix A). The Midwest also has a high percentage of electric compression. Comparatively, the West (outside California) and New England have little or no electric compression. However, flow reductions upstream may affect regions downstream that themselves have no electric compressors, such as New England. While we supplemented the interstate pipeline data with available data on major California intrastate pipelines, gaps exist in characterizing other states with significant intrastate transmission pipeline systems such as Texas.

The electric dependence is similar between interstate gas transmission and storage compressors (see section 1.4 of Appendix A). There is also evidence that the number of electrically powered compressor stations is increasing (see section 1.5 of Appendix A).

3. How severe are gas shortages caused by outages to electric compressor stations?

Determining gas shortages caused by compressor station disruptions typically requires detailed modeling of large pipeline sections. Given public data unavailability and resource constraints, a study of gas shortages caused by electric outages to all identified electric compressor stations is infeasible. Instead, we provide multiple lines of evidence demonstrating that outages of electric units at a single compressor station can be more significant than the most severe single-cause contingency typically considered in electric reliability planning. First, we conduct gas industry standard pipeline hydraulic modeling to assess the vulnerability to electric outages of the Florida Gas Transmission (FGT) Company pipeline. Next, to our knowledge we are the first to identify that the single largest cause of generator outages during the 2014 polar vortex was due to gas disruptions from an upstream electric compressor station. Finally, we compare our results to a previous analysis of gas storage locations critical to gas generator fuel security. Our intent is to motivate industry stakeholders to improve consideration of this issue in reliability and load shed planning processes, and provide methodological support for incorporation in gas generator fuel assurance assessments (NERC, 2020).

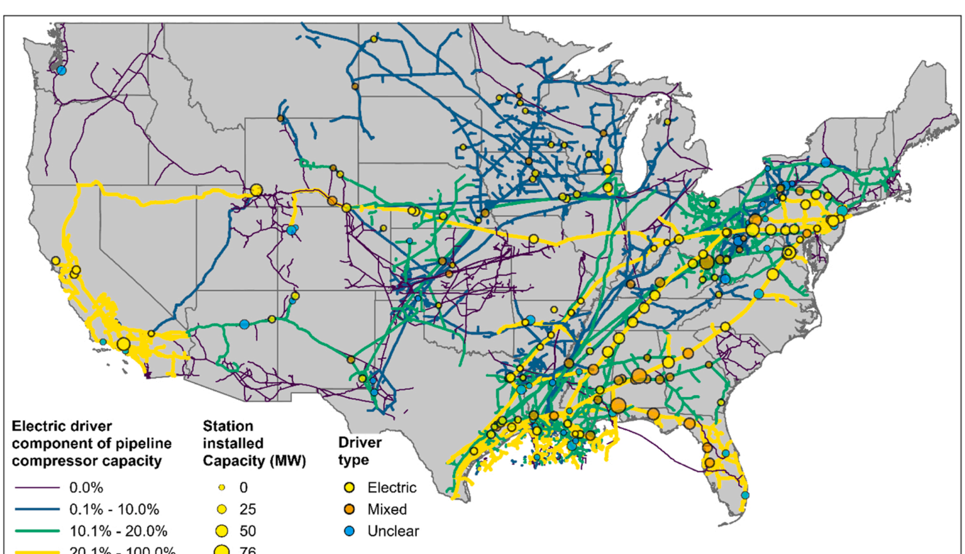

Fig. 2. Compressors stations that rely on grid electricity to operate. High concentrations are shown on some of the largest US pipeline systems (see Section 1.3 of Appendix A).

3.1. Compressor outages can cause generator outages larger than the most severe single-cause contingency considered in electric reliability planning

To demonstrate the consequence of electric compressor station outages, we examine the vulnerability of the Florida power system to gas disruptions in the Florida Panhandle, a case for which adequate data are available from public (Energy Transfer, 2022; Florida Department of Environmental Protection, n.d.) and commercial (Hitachi Energy, 2021) sources to model gas flows and where electric power disruptions from hurricanes are common (see Section 2.1 of Appendix A). We assess the vulnerability of the Florida Gas Transmission (FGT) Company pipeline, which relies on electric power at several compressor stations and is the largest gas source to Florida, where the electric grid is heavily dependent on gas generation (EIA, 2021b). We assess the effect of power outages on gas flow using pipeline hydraulic modeling and estimate how electric outages leading to the loss of multiple electrically driven units at the same or nearby stations will cause reductions in gas deliveries. See Section 3.2 of Appendix A for detailed methods and data sources for the pipeline hydraulic modeling.

Fig. 3 shows the modeled pipeline section and a pipeline pressure profile example. The modeled section on the Florida Panhandle includes three stations with mixed electric and gas compressor units, out of six stations on this section. When an outage occurs, available compressor power at the station is reduced (mixed station) or eliminated (fully electric station) leading to lower static pressure immediately downstream of the station than in normal operations. At lower static pressures, gas is less dense and therefore flows at a higher velocity. Higher velocities increase frictional losses, causing larger pressure drops downstream, which compounds the low pressure problem. Available power of downstream compressors is then insufficient to bring the pressure back up to normal operating pressure. Gas flow reductions must instead be ordered to reduce gas velocities, and thereby the pressure loss, to facilitate downstream pressure recovery. Without these gas flow reductions, which require downstream gas curtailment to electric generators, the system pressure would collapse.

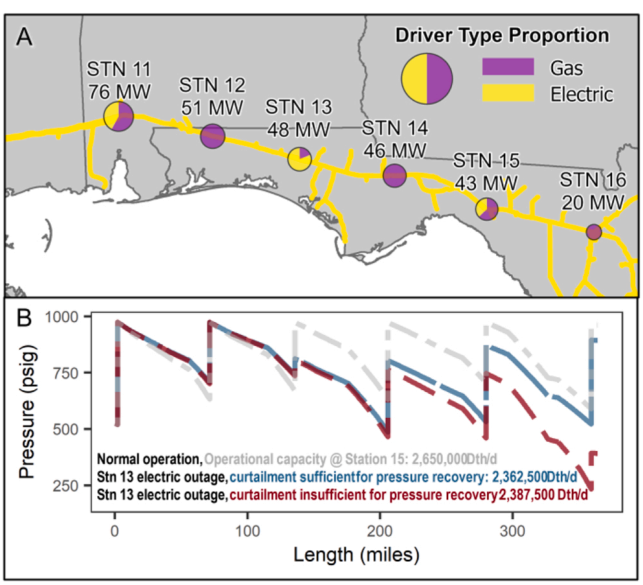

Fig. 3. Overview of Florida Gas Transmission (FGT) modelling. (A) The modeled pipeline section, from Station 11–16, and associated station compressor power. (B) The pipeline pressure profiles in the no outage (grey line) and Station 13 electric unit outage conditions (blue and red lines). An outage to Station 13 electric compressor units means gas flow must be decreased by 287,500 Dth/d to enable downstream pressure recovery (blue line), rather than cascading downstream pressure declines (red line). The flow reduction is modeled to a precision of 25,000 Dth/d (1% of Station 15 design flow) to distinguish the transition from acceptable to unacceptable pressure profiles.

Table 2 shows the magnitude of firm-contract gas curtailments and associated gas generator capacity reductions caused by compressor station electric outages for five contingency scenarios. Firm service is a contractual obligation to transport gas in nearly any condition (NERC, 2011). An electric outage at one FGT compressor station can cause gas shortages to electric generators equivalent to approximately 2.3 GW. This is larger than Florida's single largest generator contingency, a St. Lucie nuclear unit (1.08 GW (EIA, 2022b)). While NERC regions are required to maintain reliability based on the single largest generator or transmission line failure, they are not currently required to account for common-cause disruptions in fuel availability, indicating a significant planning oversight.

See section 2.3 of Appendix A for a discussion of two simultaneous compressor station outages.

A critical factor is whether a pipeline is designed to redundant reliability criteria, defined as being able to meet firm gas transport contracts after losing any single compressor unit. Unlike the electric system, this is not a regulatory mandate for the gas system (NERC, 2011); it typically exists only where pipelines and shippers have agreed to pay a premium for additional reliability. We therefore show results assuming both redundant and nonredundant design criteria. Regardless, an electric outage to a station with multiple electric units is a common-cause failure beyond the single-unit redundancy design criteria and would cause firm service curtailments.

To assess the time available to restore power after compressor station outages before flow reductions are required in our FGT analysis, Fig. 4 shows how the pressure declines over time. The minimum system pressure begins to decline 3–8 h after the outage, with sharp declines leading to system collapse beginning after 13–34 h. For a more detailed view of system operation, Figure A10 in Appendix A shows a compressor station level resolution of system transient operation for the Station 11 electric outage contingency.

In other regions, natural hazards such as ice storms, earthquakes, wildfires, and extreme temperatures can affect electric power to gas compressors. While we assess only one system, we find significant gas flow reductions from electric outages at even single electrically driven stations, suggesting similar vulnerabilities on many other systems, including those with fewer electrically driven stations. As the modeled FGT system includes mixed use compressor stations that allow the gas units at the station experiencing an outage to continue operating, we reason the electric system could be even more vulnerable to outages at other large compressor stations with only electric units.

3.2. An electrically-dependent compressor station was the largest single cause of generator outages during the 2014 polar vortex

Comparing the identified electrically-dependent stations to past gas-electric interdependency events highlights how this information can improve understanding of the causes of prior gas-electric emergencies. NERC identified that a single compressor station lost in Pennsylvania

Table 2
Gas flow and electric capacity reductions from electric outages in the modeled FGT system.

Station electric outage	Flow reduction (Dth/d)		Electric capacity reduction, combined cycle (GW)	
	Redundant	Nonredundant	Redundant	Nonredundant
11	275,000	425,000	1.5	2.3
13	250,000	287,500	1.4	1.6
11 & 13	368,750	525,000	2.0	2.9
13 & 15	262,500	325,000	1.4	1.8
11 & 12[1]	521,875	675,000	2.9	3.7

[a] While not representative of FGT electric installations, we test the sensitivity to electric unit spacing in multiple outage cases by assuming Station 12 power outages equivalent to the electric unit power at Station 13.

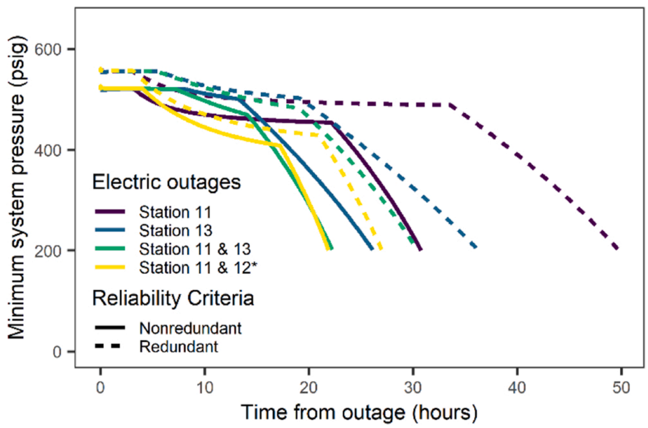

Fig. 4. Minimum system pressure over time after electric outage at time 0, while maintaining flow at pipeline capacity on the modeled FGT system.

during the 2014 polar vortex was responsible for gas shortages related to 2 GW of lost generation, approximately 15% of all cold-weather related outages in the NERC region that experienced the most generator outages (NERC, 2014). The pipeline declared force majeure (Hitachi Energy, 2021), which releases the pipeline operator from liability from not meeting firm contracts and is broadly defined in pipeline tariffs to include unplanned mechanical issues (FERC et al., 2021; Texas Eastern Transmission, 2019). A nearby compressor station also experienced an outage that did not explicitly lead to gas curtailments, though, an operational flow order was issued immediately downstream shortly afterward severely limiting flexibility in gas withdrawals (Hitachi Energy, 2021). While no causes for the compressor outages were listed (Hitachi Energy, 2021; NERC, 2014), we identify both compressor stations as electric or mixed drive. This region avoided electric load shed, but 5% voltage reductions ordered by the PJM Regional Transmission Operator may have tripped electric compressors offline, or the electric units may have been under an interruptible electric load contract like some pipeline facilities in ERCOT (Busby et al., 2021; FERC et al., 2021; King et al., 2021).

We also compare gas storage compressors we identify as electric to a previous assessment on the vulnerability of gas generation to the loss of gas storage fields (Folga et al., 2016). Storage compressors we identify as electric in California and Mississippi may each result in electric generation losses of approximately 8 GW (Figure A6 of Appendix A).

In the Texas 2021 event, there were at least seven electric outages at gas compressor stations causing flow reductions (FERC et al., 2021). Natural gas shortages (including issues at wells and processing plants) caused a cumulative total of approximately 89 GW of electric outages, deratings and failures, with a coincident peak close to 8 GW (FERC et al., 2021). Gas reductions caused by outages to electrically-dependent compressor stations will vary between pipelines according to their individual characteristics. However, the multiple historical and modeling examples we identify of > 2 GW gas reductions from single station outages in Florida, Pennsylvania, California, and Mississippi suggest that the seven electric compressor station outages in Texas may have played a significant role in gas shortages during Winter Storm Uri.

4. Discussion

A number of US natural gas pipelines are vulnerable to loss of electric power. Identifying these vulnerabilities and the data gaps encountered while evaluating them supports the need for greater reliability oversight of the natural gas system (FERC et al., 2021; Freeman et al., 2018; NASEM, 2021). In contrast to well-established reliability reporting and standards on the electrical system, the gas system has almost no reliability transparency or oversight. Our work provides quantitative support for the recommendation of a recent US National Academies study that calls for establishing a federal gas reliability organization to improve gas reliability by establishing appropriate reliability reporting and minimum industry standards (NASEM, 2021).

Appropriate data reporting from pipeline operators is an essential but missing input for improved assessments of gas reliability, including dependencies between pipelines and the electric system, and dependencies on other critical infrastructures. The lower specificity in prior gas-electric event analyses (FERC et al., 2021; FERC and NERC, 2019, 2011; NERC, 2014) on the causes and contributions of gas shortages due to gas transmission is likely due to less available information relative to the electric system, and in many cases, other parts of the gas system. Pipeline bulletin board notices could be required to precisely identify the cause and location and follow more descriptive standard event categories to assess trends over time and between pipeline operators.

To facilitate industry-wide assessments, a gas reliability organization should host a central repository of reliability events, including improved bulletin board notices. This system could draw inspiration from NERC's Generating Availability Data System (GADS), which has been used to estimate pipeline reliability using gas generator reporting (Freeman et al., 2020). It could also publish existing system design reliability criteria (e.g., redundant compressor units) to facilitate reliability assessments and better inform market participants before signing gas transportation contracts when they have the choice of multiple pipeline connections and routes. The organization could be a counterparty to NERC's ongoing efforts on gas-electric coordination.

For Florida, gas reductions can exceed the spare capacity on other gas supply pipelines (Table A8 of Appendix A); this indicates that lost gas-powered generation cannot be made up elsewhere. This analysis may be more difficult for other regions due to more pipeline and electric transmission interconnections. A starting point may be cross-referencing the regions of high gas transmission dependence on electricity we identify to NERC's identification (NERC, 2017) of gas generator "clusters" over 2 GW vulnerable to fuel disruptions, defined as having only one pipeline connection, no dual fuel capability, and insufficient electric transmission capability to mitigate simultaneous generator outages.

In consultation with stakeholders and informed by improved reliability data, a gas reliability organization should also create minimum reliability standards for the gas industry, which currently do not exist. This could include mandating pipeline companies to register electrically-dependent compressor stations as critical infrastructure with electric utilities, and for new installations considering the proportion of electrically-driven units at each station and neighboring stations. It could also codify the common industry practice of installing backup electric power for auxiliary station needs to ensure this is uniformly followed, and require periodic testing and maintenance to ensure backup generation does not fail when needed, as also occurred during the ERCOT 2021 cold weather event (FERC et al., 2021).

This organization could follow the model used in establishing NERC for the electric industry. In response to the 2003 Northeast electric blackout, estimated to cause 90 deaths and $6.6 to $15 billion (2021 $USD) in economic damage, Congress authorized FERC to charter an Electric Reliability Organization (Anderson and Bell, 2012; Freeman et al., 2018; ELCON, 2004). NERC was given this responsibility along with authority to create and enforce mandatory reporting and reliability standards in the electric industry. The 2021 Texas gas-electric event caused over 200 direct deaths, with economic damages estimated to be $80 to $130 billion. With gas shortages causing 27% of electric generator outages, this event calls for proportionate action to ensure that the gas system meets societal needs for gas reliability (FERC et al., 2021). That the event had national implications due to reduced gas supply across the country reinforces the need for a federal solution; high natural gas prices from the combination of gas production and transmission issues and increased gas demand led Minnesota, Oklahoma, Kansas, and Arkansas to spread gas costs over 2–10 years to avoid average monthly household gas bill increases of $300 to $1800 (Englund, 2021; Matthews and Oxford, 2021). The US House of Representatives recently introduced legislation that would follow this model to create an Energy Product Reliability Organization (Rush, 2021) and could benefit from including the suggestions above.

Opportunities exist within current institutional frameworks to improve gas-electric coordination. Though these depend on active participation by the gas industry, the electric industry can and should actively seek gas industry participation rather than relying on the gas industry to participate in poorly-advertised processes, such as the critical infrastructure identification process in place in Texas before Winter Storm Uri (Busby et al., 2021; FERC et al., 2021).

As a first step, electric organizations can use our identification of electrically dependent compressor stations to ensure that these stations are not included in electric utility load shed schemes in cases of rolling blackouts. This is a simple yet critical opportunity; before the 2021 event only 35 critical gas facilities were identified on ERCOT lists, to which one gas utility in Texas alone added 168 facilities after the freeze (Hartley et al., 2022). Similar gaps in critical gas infrastructure identification likely exist elsewhere in the US.

A better understanding of this interdependency can also lead to better industry risk assessment, such as including electric compressor station outage scenarios in natural gas fuel assurance assessments (Levitan & Associates, 2015; NERC, 2020) and in emerging gas-electric interdependency models (Bindewald and Yuan, 2020; Portante et al., 2017). Pipeline curtailment priorities can be updated to reflect the increased dependence of the electric grid and avoid negative feedback loops, so that priority ranks are changed or gas curtailments explicitly consider electric system needs (Freeman et al., 2020). A modest step in the right direction has been taken by SoCalGas, whose curtailment procedure sub-divides gas generators into curtailment priorities and explicitly requires coordination with the electric system operator, though it is unclear if these measures will be sufficient in the long-term (Southern California Gas Company, 2022). And, if gas curtailments to electric generators must occur, coordinating with the electric system operator to curtail gas from less efficient generators before more efficient generators while meeting electric transmission constraints reduces electric power loss; equal gas curtailments to a simple cycle generator before a combined cycle generator reduces electric outages 31% on average (EIA, n.d.).

One reason electric compressor units are installed is due to concerns over air emissions from gas-driven units (FERC and NERC, 2011), but as we have shown this creates an unintended consequence of introducing new reliability concerns. Our results can be used to better understand these tradeoffs. This may be particularly important for new compressor installations near cities (Figure A7 of Appendix A). A reasonable compromise may be to install mixed units at individual stations upwind of significant population centers, where the electric units run most of the year and gas units are used as peaking units and in case of a power outage. This likely requires regulatory direction from one or both of the air quality and rate regulator, as it is more economical to run electric units than gas units only at high gas-to-electricity price ratios (Table A5 of Appendix A). For example, the air quality regulator could set operating hour limits on gas units at mixed stations, more than the hours required to run to meet system peak capacity in a relatively high demand year.

5. Conclusion

We find that approximately 10% of US interstate pipeline compressor stations depend on electricity, with several large pipelines quite vulnerable to electric outages. During times of high gas demand, electric outages that disable compressors at these stations can significantly reduce gas available to downstream generating stations. In some cases, the resulting outages could be as large as or larger than the single-cause electric system contingencies that utility operators currently employ when assessing the reliability of their system. This vulnerability should be included in assessments of power system reliability and resilience. Doing so will require much-improved reporting of gas system operations.

CRediT authorship contribution statement

Sean Smillie: Visualization, Conceptualization, Data curation, Formal analysis, Methodology, Writing - original draft. **M. Granger Morgan:** Writing – review & editing. **Jay Apt:** Resources, Writing – review & editing, Supervision.

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.

Data Availability

A list of electrically-dependent compressor stations is available as Appendix B, organized by electric utility, NERC region, and Regional Transmission Operator. Other data, code, and modeling files are available on GitHub: https://github.com/ssmil/electric_compressors. Aggregated historical annual energy consumption for each compressor station was obtained from a commercial data source and cannot be published due to contractual terms; however, the underlying annual data is publicly available in non-aggregated form from a government website (FERC), as referenced in Methods.

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Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.tej.2023.107251.

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