Fueling the Debate:
Examining the Cost, Emissions, and Security Complexities in Electrifying Pipeline Compression

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Abstract

Natural gas-powered electricity generation enhances reliability in the U.S. electric power grid and provides the necessary backup supply that supports growth in renewable forms of energy. The nation's natural gas supply continues to grow, leading to stable and affordable energy costs for customers. As demand for lower carbon energy intensifies, natural gas pipeline operators like Williams are exploring options to reduce greenhouse gas emissions during the transmission of natural gas. Improvements in operational efficiency and design have already led to a significant reduction in fugitive methane emissions. Pipeline operations also create carbon dioxide, the mitigation of which is distinct from that of methane.

One solution under consideration is the replacement of combustion-driven compression with electric-driven compression. This switch will lead to a significant reduction in station Scope 1 emissions, particularly carbon dioxide. It is important to consider the additional challenges and consequences that come with replacing gas-fired drivers with electric motor drives. For example, not only do electric drivers produce Scope 2 emissions, but their installation represents a coupling of two systems critical to the nation's energy system, reducing redundancy across the value chain. In the interest of analyzing these challenges and consequences, Williams conducted a thorough examination of the potential impacts of transmission station electrification.

Electrification of compressor stations will expose the energy value chain to further reliability risks with highly regionalized greenhouse gas reductions. Installation of electric drives should be considered on a case-by-case basis alongside other decarbonization strategies to ensure the continued delivery of clean, reliable energy.

Greenhouse Gas Mitigation through Electric Compression

In limited areas across the United States, the Scope 2 emissions associated with electrical compression are greater than the Scope 1 emissions of gas-fired compression. This suggests that electrification is not an unalloyed greenhouse gas mitigation tactic and should be considered carefully, project-by-project.

Costs Associated with Electric Compression

While electrifying compression presents cost challenges to a pipeline operator, it also directly impacts consumer rates. Generally, electricity costs more per megawatt of motive force than gas, and this additional cost is passed onto consumers. Several factors inflate the cost of electricity, including the need for additional infrastructure and the fact that electricity prices are exposed to demand surge pricing. Investing in more cost-effective methods of decarbonization could protect the energy value chain from a price increase feedback loop.

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Reliability Concerns

Perhaps the biggest concern when electrifying compressor stations is the reliability of the bulk-power system. Current state analyses find that nearly half of the nation's bulk power system is vulnerable to failing during extreme weather events. Furthermore, future state analyses highlight the need for reliable natural gas delivery if total grid reliability is to be improved. Electrifying compression reduces the reliability of natural gas transportation. All-electric stations cannot be supported by supplemental generators and become inoperable during grid emergencies. The interdependence between fully electric stations and the wider grid can lead to difficulties recovering from blackouts.

Security Concerns

The past decade has seen a rise in both physical and cyber-attacks on critical infrastructure systems, including natural gas and electric transmission systems. Recent physical attacks on substations reveal a massive single point of failure within the electricity value chain; subjecting the natural gas value chain to that same vulnerability without substantial improvements represents an oversight. Similarly, the more interconnected the two systems become, the more vulnerable each is to cyber-attacks carried out on the other.

Introduction

Williams handles approximately one-third of the natural gas in the United States across an extensive midstream and transmission footprint. The company has taken important steps to meet growing energy demand and achieve industry-leading emissions reductions. In 2020, Williams was the first midstream company to announce a climate commitment, pledging a reduction in greenhouse gas (GHG) emissions through optimized design, operational efficiency, and investment in emerging technology. Williams has succeeded in reducing methane emission intensity year-over-year since 2018 but is always seeking new opportunities to improve environmental stewardship while maintaining operational excellence.

Across the natural gas industry, operators have succeeded in reducing methane emissions. Williams has undertaken extensive purposeful and fugitive methane mitigation efforts, such as blowdown recompression and enhanced leak detection and repair (LDAR) programs. These efforts have led to a methane reduction of 60% on an intensity basis since 2018. Williams remains committed to reducing methane emissions from wellhead to burner tip, in part through implementation of its NextGen Gas initiative, allowing for the certification of low-emission gas pathways and the acquisition of actionable emissions data.

Williams also strives to mitigate carbon dioxide (CO2). Carbon dioxide occurs naturally in the gas stream and is therefore duly mitigated when methane emissions are reduced with the aforementioned techniques. However, the primary source of Williams' CO2 occurs during combustion. Combustion is the motive force used by gas-fired drivers to power natural gas compressors. The most common approach in mitigating this combustion CO2e is through electrification, or the replacement of

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combustion-based drivers like turbines and engines with electric motor drives (EMDs). EMDs are powered by electricity rather than hydrocarbon combustion, meaning the emissions associated with EMD operation (Scope 1 emissions) are zero. Rather, EMDs contribute to Scope 2 emissions, or emissions associated with the generation of purchased power.

Comparing the GHG profiles of each driver is most effective when done on a basis of power output. Figure 1 shows the calculated emissions for a gas-driven Turbine compared to the average emissions of an EMD during 2021 per unit of brake horsepower hour.

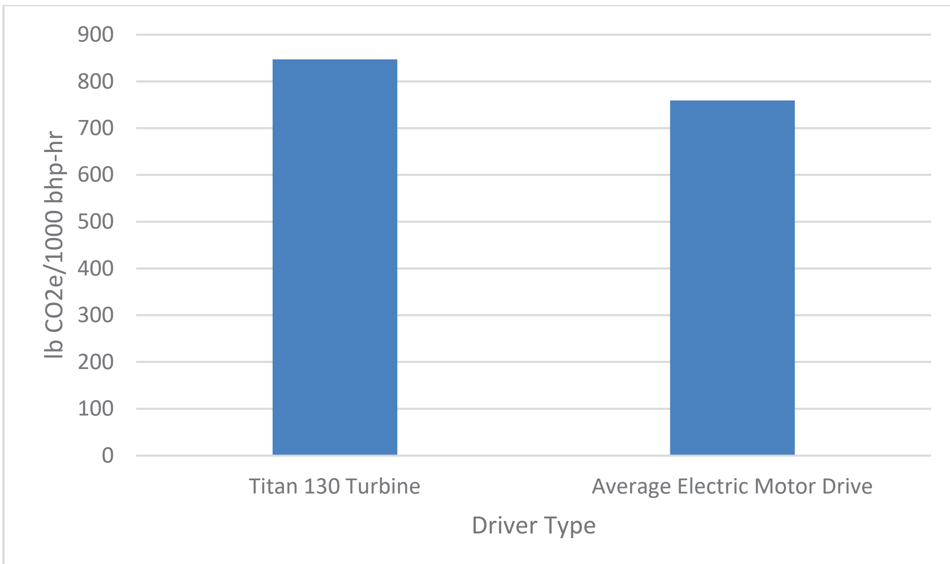

Figure 1. 2021 Driver Emissions Normalized by Horsepower Output

On average, per horsepower-hour of motive energy delivered to a compressor, the Titan 130 produced slightly more GHG emissions than the EMD average. A crucial factor to consider when evaluating the GHG reduction potential of electrification is the regional variability of Scope 2 carbon intensity (the quantity of CO_2e emissions created per energy delivered). In Figure 1, the Average Electric Motor Drive bar is an average of EPA e-GRID subregions in 2021. The grid does not operate at an average, so careful consideration is needed to ensure published emissions rates do not inhibit emission reduction pathways within natural gas supply chains.

The electrification of transmission compression also raises important questions surrounding cost, not only to the company, but to consumers. Because of the ratemaking mechanisms in interstate pipeline transmission contracts, a portion of capital and operational spend by operators is passed onto consumers, increasing the commodity price of natural gas used in heating, cooking, and electricity generation. Other decarbonization strategies such as hydrogen blending in fuel gas have the capability of providing more cost-effective greenhouse gas mitigation than electrification.

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Electric compression presents possible reliability concerns for the natural gas transmission system that cannot be overlooked. Major weather events such as 2021's Winter Storm Uri continue to threaten U.S. electrical infrastructure, but inclement weather is not the only threat to the grid. Physical and cyber-attacks on energy infrastructure reached a decade-long peak in 2022. The ongoing war in Ukraine is illustrative of the importance of energy infrastructure to national security, causing many in the U.S. to call for security improvements. Without extensive overhauls to the grid's physical and cybersecurity, electrification could create an unignorable point of critical risk.

This study endeavors to present a holistic understanding of the benefits, detriments, and implications of widespread electrification of transmission compression in the interest of ensuring reliable, clean energy for years to come.

Methods

Greenhouse Gas Emissions

In studying the GHG emissions of each driver, it was assumed that all emissions not directly tied to the driver remained constant across both driver types. GHG emissions from natural gas-fired turbines primarily occur at the exhaust stack due to combustion. The fifth edition of AP-42, *Compilation of Air Pollutant Emissions Factors*, published by the United States Environmental Protection Agency (EPA), was used as the basis for this analysis. AP-42 includes emissions rates for each of the three major GHGs: CH_4, N_2O, and CO_2[1] (Environmental Protection Agency, 1995). CO_2 represents 99% of all GHG emissions in a combustion turbine, but CH_4 and N_2O were included in this analysis for completeness. As is customary in GHG analysis, these three values were normalized into CO_2 equivalents (CO_2e) using Global Warming Potentials (GWPs)[2] (World Resources Institute, 2020). These emissions factors are calculated per unit of fuel input energy; to normalize against output energy, the turbine heat rate was applied to the AP-42 factors. The heat rate of a turbine demonstrates the amount of fuel input energy it must consume to produce one unit of mechanical output energy. Equations used in calculating turbine emissions rates can be found in Appendix A.

Turbine heat rates vary based on multiple factors, including ambient temperature, elevation, percent load, and model. To simplify the analysis, standard inlet and exhaust back pressures of 4" H_2O each, 1000 ft elevation losses, and high loads (>80%) were assumed when identifying heat rates from manufacturer curves. A Solar Turbines Titan 130 was chosen as representative of this analysis due to its prevalence – current and planned – across Williams' fleet.

1 AP-42, Vol. I, 3.2, Table 3.1-2a. provides factors of 110 lb CO2/MMBtu, 0.003 lb N2O/MMBtu, and 0.00086 lb CH4/MMBtu on a per fuel input basis for stationary gas turbines.

2 GWPs taken from the Greenhouse Gas Protocol Fourth Assessment Report (AR4) on the basis of 100-year time horizon (CO2 =1, CH4 =25, N2O=298)

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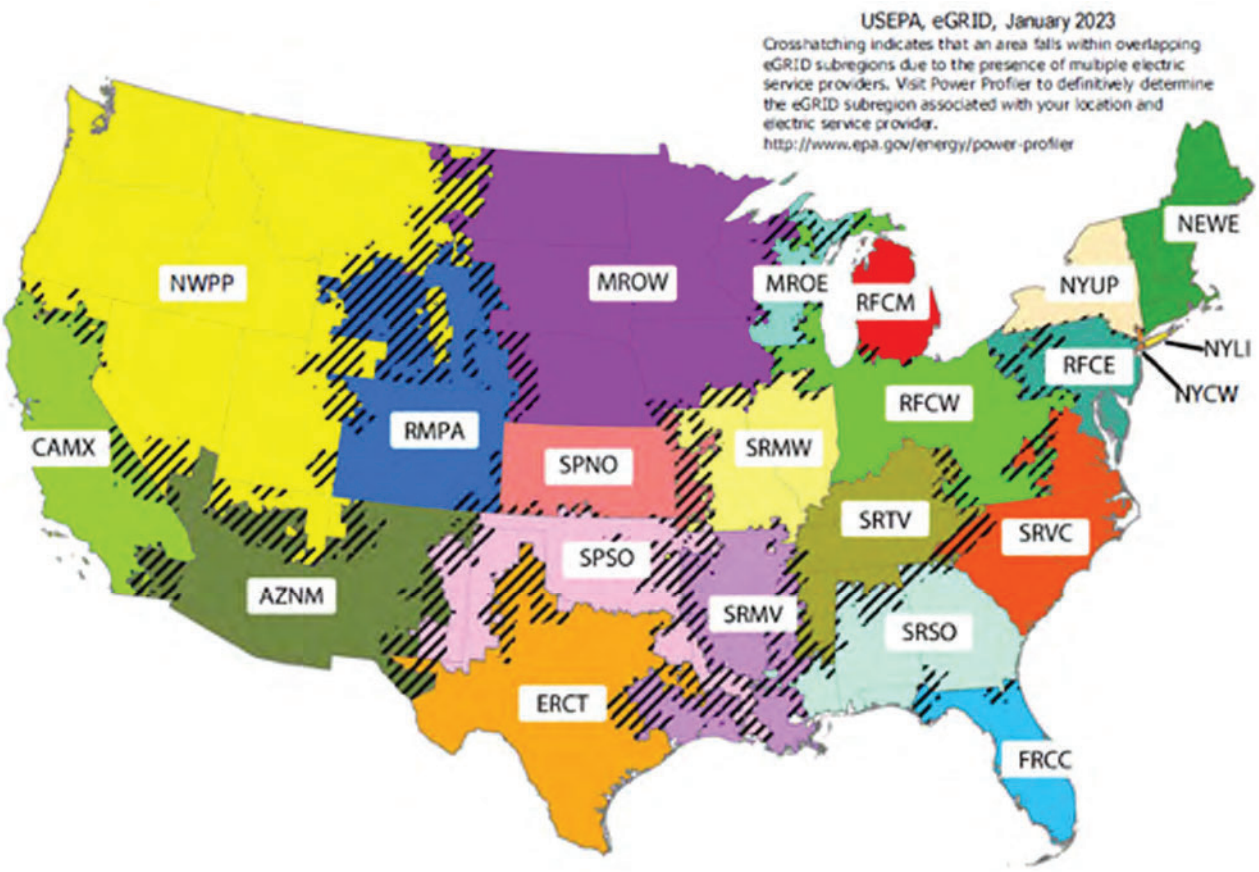
Because emissions associated with the use of electricity are highly dependent on the origin of the electricity, grid emissions were studied by region. The EPA publishes the Emissions and Generation Resource Integrated Database (eGRID) annually, providing regional emission factors that can be used to calculate Scope 2 emissions. eGRID data is broken into 29 subregions (Figure 2).



Source: EPA

Figure 2. EPA e-GRID Subregion and NERC Region Representational Map

This analysis was conducted using the 2021 eGRID dataset, published in January of 2023. eGRID datasets contain power generation emissions at the unit, plant, state, subregion, and national levels. Associated emissions at the plant level were aggregated up to the subregion level in this analysis. Emissions associated with each generation type were then summed and divided by total electricity generated to obtain carbon intensities, in lb CO_2e/MWh, by generation type for each subregion. Emissions rates as calculated in eGRID change on an annual basis and are likely to continue to change in the future. This analysis only considered a snapshot of regional emissions profiles, as changes in grid emissions are subject to many factors, such as unit retirements, total demand, and energy policy.

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The EPA emissions rates do consider some parts of electrical efficiency, such as the efficiency of the generating unit and electricity lost across transmission lines. In the case of an EMD at a compressor station, additional efficiency losses must be considered. Included in the efficiency factor applied in this analysis were losses due to transformers and mechanical losses in the EMD. Equations used in grid emissions calculation can be found in Appendix B.

Cost

Transmission pipelines are a contract-based operation where the rates and fees to transport are originally set at the time of installation and revisited periodically by the operator, the consumer, and the Federal Energy Regulatory Commission (FERC) through a process known as a rate case filling. Rate case filings ensure that the rate and fees will cover ongoing operating costs incurred by the operator, that the operator may make a reasonable return on investment, and that operators are not charging consumers a disproportionate amount to transport gas.

When considering electrification as a path toward reducing GHG emissions in the transmission segment, it is important to consider the cost implications. Operators often recoup the cost of construction, operation and maintenance, or compliance work from consumers through a ratemaking mechanism approved by FERC. In this way, higher cost methods of GHG reduction do not only impact the operator, but also natural gas consumers. Ratemaking is multifactorial and was not considered in detail in this analysis. Rather, general trends in the cost to operate both EMDs and turbines were analyzed with the recognition that operating and maintenance costs are in large part subsidized by end-users.

Choosing pathways to decarbonization that are economically sensible allows for minimal impact to consumer rates as well as quicker adoption of these solutions. Comparing the direct costs of carbon abatement technology can be misleading, as a higher cost strategy could also provide greater carbon savings. One way to control for total carbon saved is through the application of a cost of carbon, but neither Williams nor the United States at large have implemented widespread costs of carbon. Instead, this analysis used cost effectiveness as a comparison. The cost effectiveness of a decarbonization pathway can be calculated as the dollar spent per unit of CO_2e mitigated by a specific technology.

The cost of electrification was compared with that of hydrogen blending in turbine fuel gas. Hydrogen blending in turbine fuel gas has been verified by Solar Turbines at levels up to 20%[3], the practice requires fewer physical adaptations when compared to other emerging technologies, and the commodity price of hydrogen can easily be compared to that of electricity.

3 Solar Turbines has verified up to 100% hydrogen blending in conventional combustion systems but has limited SoLoNOx verification to 20%. Most of Williams' turbines use SoLoNOx combustion, which Solar Turbines expects to develop at 100% blending capability by 2030.

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Results and Discussion

Regional Emissions Analysis

Average emissions for EMDs and a Solar Titan 130 turbine were normalized by 1000 brake horsepower-hours of shaft output energy. A comparison of EMDs in each EPA subregion in 2021 and the Titan 130 is depicted in Figure 3. Subregions covering Alaska, Hawaii, and Puerto Rico were not included in this analysis.

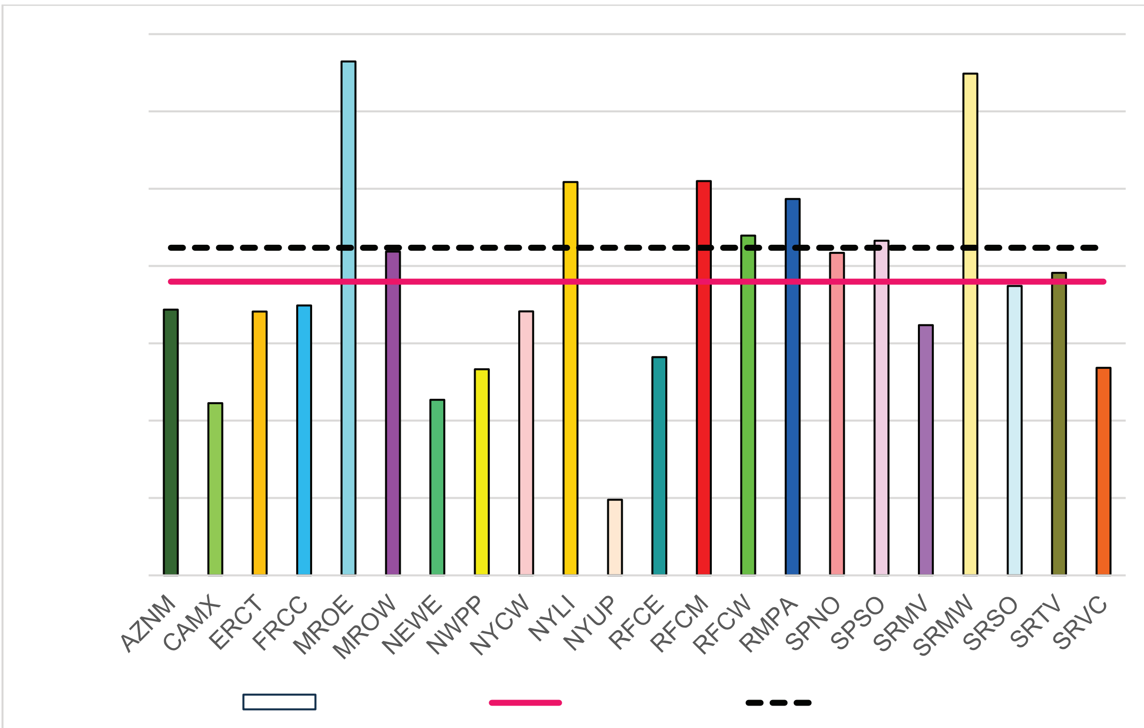

Figure 3. Scope 2 Average Emissions of EPA Subregions in 2021 vs. Scope 1 Emissions of Titan 130

Figure 3 demonstrates the importance of considering electrification regionally. The national average grid emission rate is lower than that of a Titan 130, but emission rates vary widely by subregion. 68% of the subregions shown in Figure 3 are less carbon intense, on an annual average basis, than the Titan 130. However, MROE and SRMW, for example, are 57% and 53% more carbon intense than a Titan 130, respectively. The differences in carbon intensity across these subregions can be accounted for by different regional grid mixes; both MROE and SRMW utilized coal for over 50% of electricity generation in 2021. Conversely, subregions with lower annual emissions generally employed both natural gas and renewable generation units at higher rates.

In most of its future-state modeling, the U.S. Energy Information Administration (EIA) predicts that annual average grid emissions will decrease over time across the United States due to renewables displacing fossil fuels in the electricity mix. EIA notes that these replacements are primarily driven

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by predicted declines in renewable technology cost and rising subsidies for renewable power. EIA's models suggest that electric compression has the potential to broadly reduce carbon emissions at some future state, if political and economic incentives for renewable power generation remain steady or increase. Unfortunately, in its current state, actual grid operations are often more carbon intense than would be desirable for an operator.

When looking at Williams-specific EMD usage on the Transco System, an important relationship between the location of the EMDs on Transco and the emissions rates of the subregions where the EMDs are located is shown.

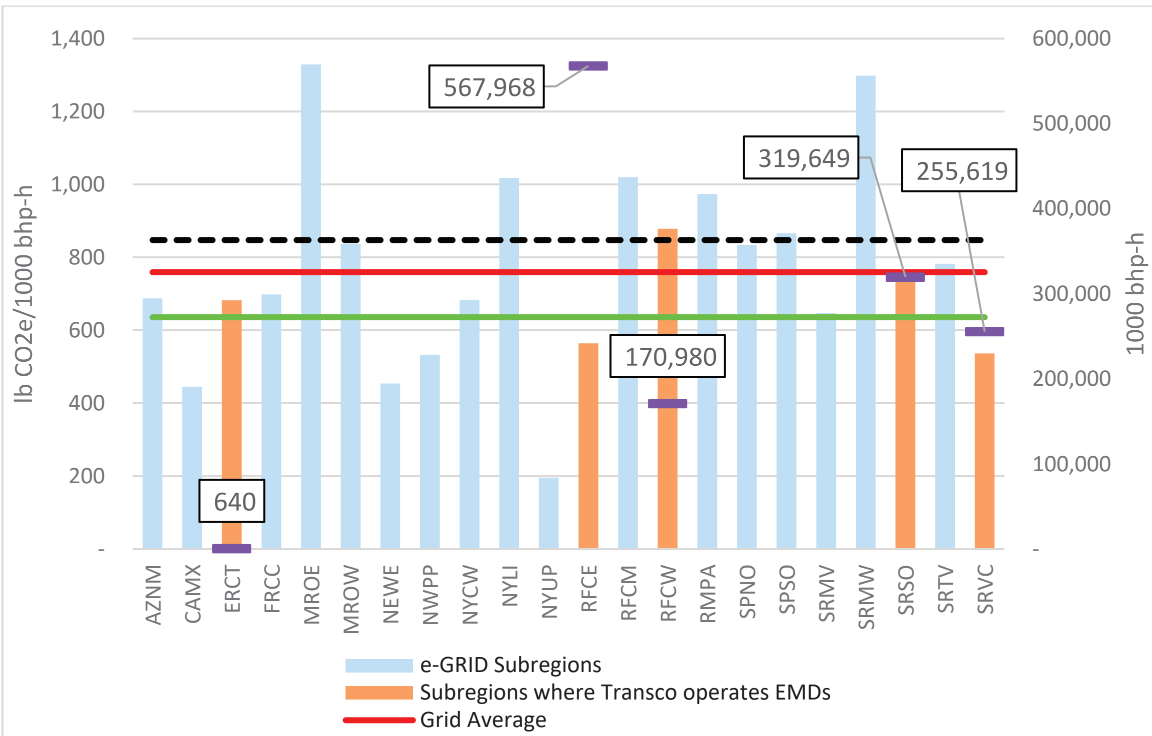

Figure 4. Scope 2 Emissions of EPA Subregions in 2021 vs. Scope 1 Emissions of Titan 130 overlayed with Transco EMD usage in 2021

Figure 4 shows the average emissions rate for each e-GRID subregion displayed along with the average emissions rate of a Titan-130 and the average emissions rate of all the subregions studied in this paper. In addition, each subregion where Transco operates EMDs is colored orange and the total 2021 run time of the units in each subregion are plotted over the chart with a secondary axis in 1000 bhp-h. In doing this, it is apparent that Transco EMDs in subregions with lower emissions rates than the national average are utilized more than the Transco EMDs in regions with higher emissions rates. This is seen in RFCE, SRSO, and SRVC where the EMD usage is higher than the usage in the other subregions. Vice-a-versa, the EMD usage in grids that have a higher emissions rate than a Titan-130

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is lower relative to the EMD usage in other grids; the lower EMD usage in RFCW shows this. The usage in ERCT is excluded from this comparison since the EMDs in the grid are used very sparingly.

Therefore, the average emissions rate of Transco EMDs is lower than the national average. The total run hours and the total electrical load of each EMD on Transco in 2021 were pulled, converted to an average emissions rate using the subregion emissions rates, and then graphed using the green line. When comparing this green line and the red line, it is apparent that the average emissions rate of Transco EMDs is lower than the national average due to the overwhelming EMD usage in subregions with lower emissions rates. This shows that Transco prioritizes installing and operating EMDs in locations that have a lower average emissions rate than the rest of the grid.

It is important to note that the above analysis employs annual average fuel mix values for each subregion. Practically, regional fuel mixes are subject to hourly change based on wider system demand and pricing. ISO/RTOs schedule lowest cost generation first to meet baseload demand. Baseload generators typically have a high minimum run time, often running 24 hours per day, seven days a week. Because demand shifts throughout the day, it is most economical to supplement baseload generation with marginal generators with short start-up and minimum run times. ISO/RTOs dispatch additional generating units to meet demand based on marginal cost. The units with the lowest operating cost are dispatched first, progressing in cost until the system demand is met. Marginal cost bids occur in five-minute increments, allowing fuel mix to significantly vary hour by hour. For an EMD that runs 24 hours per day, seven days a week, annual averages are an acceptable estimation of grid-associated emissions. In practice, EMDs along Williams' Transco Pipeline operate intermittently, often to supply gas to those marginal resources during peak periods. Considering marginal generation emissions separately can provide a fuller picture of the effect of electric compression on GHG emissions.

PJM Interconnection is the RTO covering primarily the RFCW and RFCE subregions. In the context of grid systems like PJM, Figure 5 delineates the comprehensive breakdown of power generation sources. This illustration provides a chronological analysis of the evolution in energy sources over the past 14 years. Natural gas currently dominates the power generation mix in PJM, but it is important to observe that during this period, although coal use has declined, it is still the second largest power generation source.

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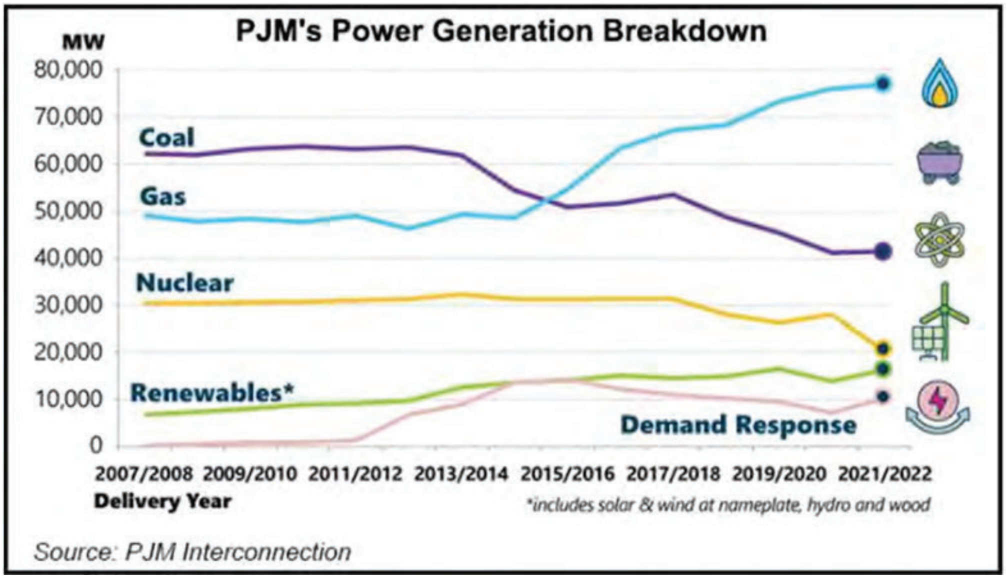
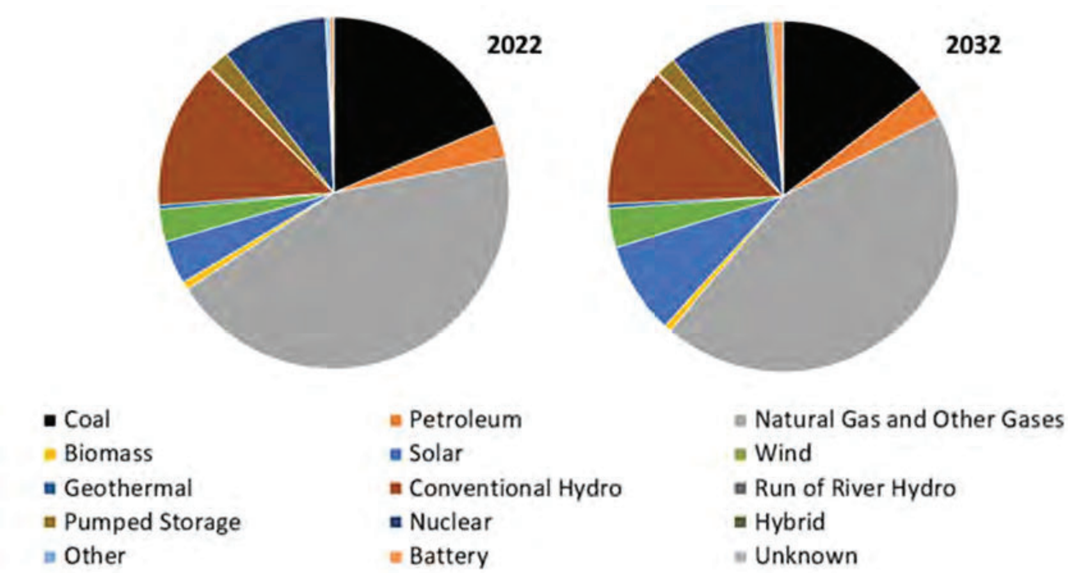


Figure 5. PJM's Power Generation Breakdown

Across the bulk power system, natural gas provides the single largest on-peak capacity of any other resource. In the 2022 Long Term Reliability Assessment, the North American Electric Reliability Corporation (NERC) analyzed retirements and resource additions, finding this trend would hold true throughout the following decade (Figure 6).



(National Electric Reliability Council, 2022)

Figure 6. 2022-2032 BPS On-Peak Capacity by Fuel Type

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NERC identifies resources like solar and wind as "variable energy resources" (VERS) due to the variability of their generation capacity over a given day. As seen in Figure 6, VERs are expected to experience modest on-peak capacity growth across the bulk power system, but even this modest growth presents challenges. NERC stresses the importance of investing in flexible resources such as natural gas to offset the variability of solar and wind. Not only does this present system reliability concerns as discussed in the "Reliability" section, but it moderates the overall impact of electrification on compressor station GHGs.

PJM provides a strong basis to study this phenomenon due to the wide variability in generation resources across the market. In their 2021 Emissions Report, PJM published data regarding marginal resource fuel mix and marginal emissions as compared to annual system averages. Fossil fuel generators, specifically combined cycle gas turbine generators, make up a majority of PJM marginal units, as seen in Table 1.

Table 1. PJM Marginal Units by Fuel Type and Technology

Gas	Combined Cycle	57%
Coal	Steam	14%
Wind	Wind	11%
Gas	Combustion Turbine (CT)	10%
Gas	Steam	1%
Oil	CT	1%
Uranium	Steam	1%
Other	Solar	1%
Gas	Reciprocating Internal Combustion Engine (RICE)	1%

(PJM Interconnection, 2021)

In the same report, PJM published marginal CO_2 emissions rates from 2017-2021. Table 2 shows monthly average percent differences between the marginal and system emissions rates for 2021.

Table 2. Average Monthly On- and Off-Peak % Difference between Marginal Emissions Rate and System Average

+/-% System Avg	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	34%	8%	31%	14%	49%	27%	35%	34%	29%	46%	35%	29%
Off-Peak	33%	11%	29%	33%	34%	24%	27%	26%	20%	29%	8%	17%

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Marginal units consistently generate greater emissions than the system average, even during off-peak periods. Table 2 illustrates the annual variability of an EMD serviced by PJM, with the Titan-130 included for reference. The Titan 130 is also corrected for monthly variability using high-end monthly average inlet air temperatures across the region (see Appendix C).

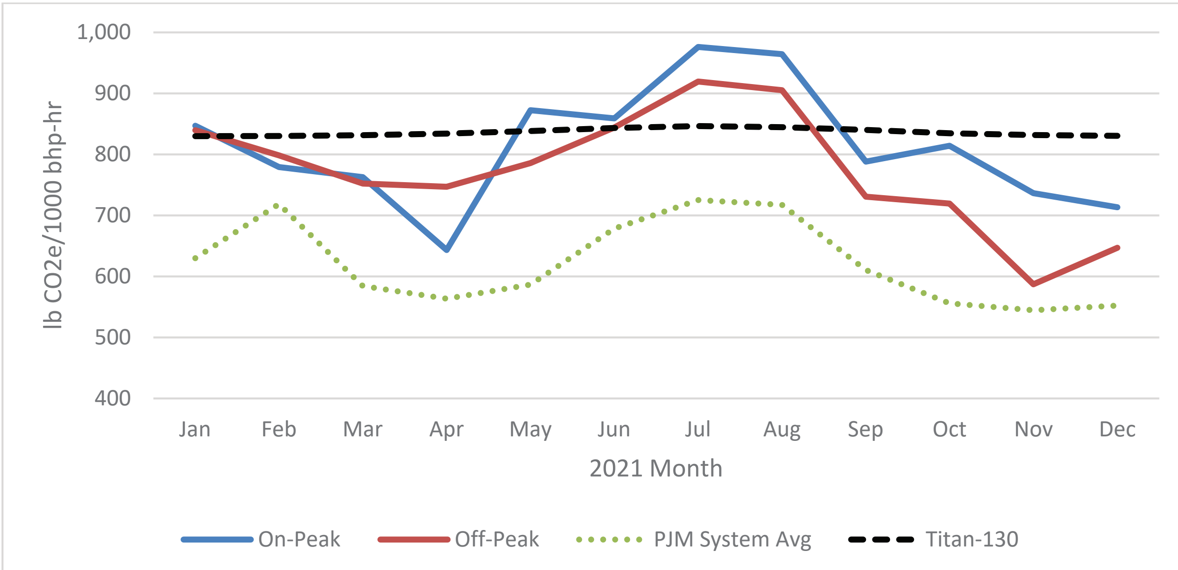

Figure 7. On- and Off-Peak Marginal Unit Emissions across PJM vs. Titan-130

The PJM system has a lower average emissions profile compared to the Titan 130, but the emissions vary significantly due to on- and off-peak marginal generation. During four of the months studied, the Titan 130 produces lower GHG emissions than on-peak marginal generators. The results in Figure 7 suggest two conclusions: First, electrification may increase station GHG emissions for compressor stations that support operators in serving marginal demand. Second, even after accounting for turbine efficiency derating due to inlet air temperature, the variability of the grid's emissions profile makes it difficult to predict practical emissions reductions by electric drives.

Despite this unreliable and occasionally worse emissions profile, operators still choose electric compression. Often, operators are choosing EMDs so that they might simplify a complex permitting process. A recent National Petroleum Council (NPC) report concluded that "Overlapping and duplicative regulatory requirements, inconsistencies across multiple federal and state agencies, and unnecessarily lengthy administrative procedures have created a complex and unpredictable permitting process" (National Petroleum Council, 2019). The report goes on to describe defensive measures in which operators engage to simplify the permitting process, such as drafting lengthy environmental impact statements. Selection of EMD compression is a similar defensive measure, as it allows companies to permit a project without involving additional agencies, such as state air boards. The NPC noted that, while permitting reform efforts were underway, further improvements were necessary. Permitting improvements will not only expedite project timelines and reduce costs; they will allow operators to make equipment selections based on factors such as carbon intensity, reliability, and efficiency, rather than permitting complexity.

Emerging Technology in Emissions Reduction

Natural gas turbines evolve with continuous research and development. Previously, turbine suppliers focused on reducing NOx and carbon monoxide emissions at a turbine stack as these pollutants are harmful to human health at elevated quantities. With increased awareness as to the harmful dispersed effects of GHGs, suppliers and operators alike are innovating to decrease combustion related GHG emissions.

Hydrogen blending in driver fuel gas has become particularly attractive as a GHG emissions reduction technique. Hydrogen can be blended with natural gas, and because the combustion of hydrogen only produces heat and water, combustion of a hydrogen/methane blend results in significantly lower GHG emissions[4]. Figure 8 illustrates possible CO2 and methane emissions reductions from different hydrogen blends. Values used to calculate hydrogen blend emissions can be found in Appendix E. Figure 8 also shows the effect of hydrogen blending on the overall net heating value (NHV) of the gas mixture. Because the decrease in NHV outpaces the reduction in CO2e emissions until blends of 90% are reached, further analysis is needed to understand the direct impact of hydrogen blending on GHG reduction.

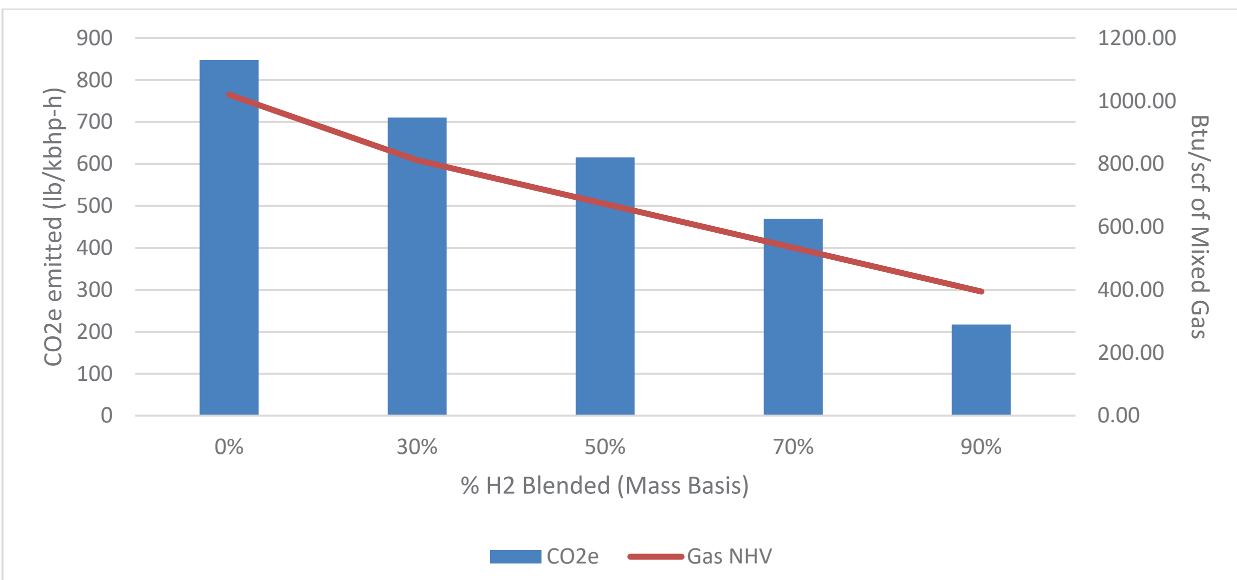

Figure 8. Effect of H2 Blending on Turbine CO2e Emissions

4 Hydrogen blending, while effective at mitigating combustion CO2, does contribute to an up to 1.4 times increase in NOx production (see Appendix E). NOx is a product of heating air to high temperatures, and though it is not a GHG, it has been shown to negatively impact air quality.

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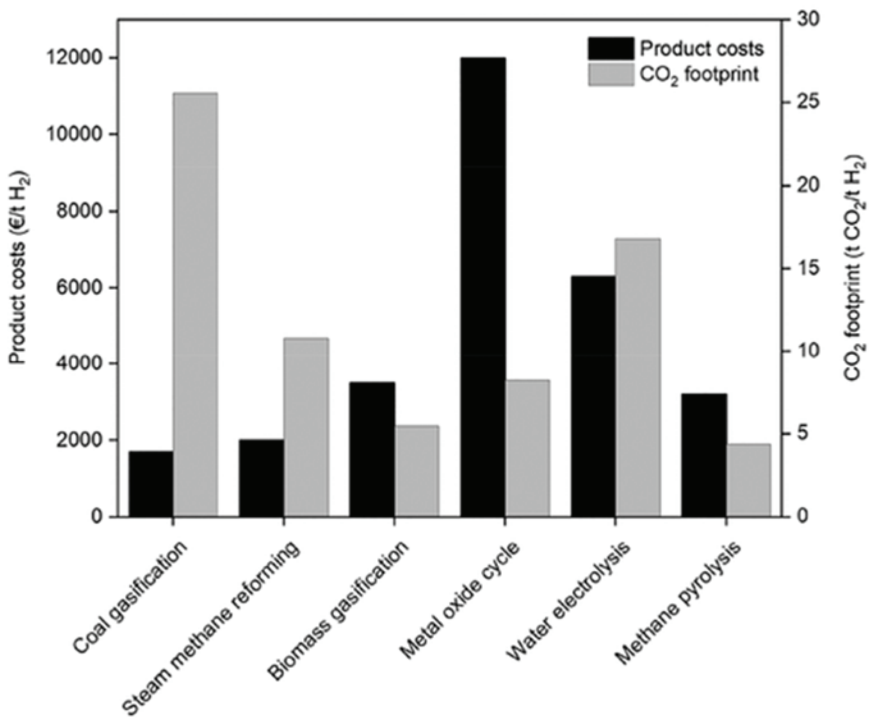
Hydrogen production currently requires the extraction of molecular hydrogen (H2) from existing molecules such as methane or water. These extraction processes are known as steam-methane reformation (SMR) and electrolysis, respectively. Neither method is carbon neutral, as SMR produces carbon dioxide as a product, and electrolysis is subject to the earlier discussed emissions profiles of local electric grids. SMR in combination with carbon capture technology allows for low-cost, clean hydrogen production, but this requires installation of two additional resource apparatuses. A simpler application for clean hydrogen production can be found in methane pyrolysis. Methane pyrolysis, or the thermal decomposition of methane, results in hydrogen and solid carbon, thus preventing the release of GHGs. A study published in Industrial & Engineering Chemistry Research found that methane pyrolysis produced the smallest CO2e footprint at the lowest cost of all hydrogen production technologies (Figure 9).



(Sanchez-Bastardo, Schlogl, & Ruland, 2021)

Figure 9. Product Costs and CO2 Footprint of Different Hydrogen Production Technologies

Williams remains committed to the research and development of hydrogen-based combustion, including through its investment in hydrogen pyrolysis startup Aurora Hydrogen. While hydrogen production is not yet cost effective, increases in demand and at-scale production will continue to drive down costs over the next decade[5] (Sanchez-Bastardo, Schlogl, & Ruland, 2021).

5 Scaled production of hydrogen could impact Scope 2 emissions, as gas-fired powerplants might receive a hydrogen-methane blend from blended pipelines; however, the emissions reductions would occur at a slower rate than shown in Figure 8 due to gas-fired plants accounting for only a portion of the grid's emissions.

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Carbon capture technology provides another path to reduce gas-fired turbine emissions. While hydrogen blending reduces emissions during the combustion reaction, carbon capture reduces emissions at the exhaust stage of a typical methane combustion reaction. The most advanced carbon capture technology is solvent-based; flue gas is sent to a CO2 absorption column wherein amine absorbs the CO2. The rich amine is then sent to a second vessel, where it is heated to exhaust pure CO2 for compression and transportation. Post combustion carbon capture (PCCC) suffers from the low concentration of CO2 in flue gas, requiring larger amine units and leading to lower capture efficiencies; however, some new solvent technology boasts flue gas capture rates up to 98% (Mitsubishi Heavy Industries, Ltd., 2021). Continued evaluation of the cost effectiveness of mitigating GHG emissions through hydrogen blending and carbon capture is underway.

A third path to reducing the overall emissions at a compressor station is through simply increasing energy efficiency. Because turbines lose nearly 63% of energy input to heat during combustion, waste heat recovery (WHR) units can aid in reducing Scope 2 emissions. In this application, WHR units operate by converting the exhaust gas thermal energy into a more useable form to achieve higher overall thermal efficiency. This application can allow compressor stations to achieve greater independence from the grid, as well as eliminate a portion of Scope 2 emissions associated with operation.

Mature WHR systems in the natural gas industry include the Steam Rankin Cycle (SRC) and Organic Rankin Cycle (ORC) but each of these systems presents significant challenges. Water availability and economies of scale prevent SRC from proliferating. ORC, while more feasible in this application, recovers waste at only about 25% efficiency. ORC has been the standard WHR system in the natural gas industry, but recent research and development suggests that supercritical carbon dioxide (sCO2) technology might be better suited for the natural gas application.

During the sCO2 cycle, carbon dioxide is compressed and heated beyond its critical point, resulting in the creation of a dense working fluid with a high volumetric heat capacity. This increase in working fluid density leads to significantly more compact system components compared to ORC or SRC systems, without compromising performance. In 2022, the Southwest Research Institute (SwRI) conducted sCO2 testing on a Titan 130, where the WHR system was able to produce 5.660 MW of electricity at an efficiency of 46% (Allison, Wilkes, & Schmitt, 2022).

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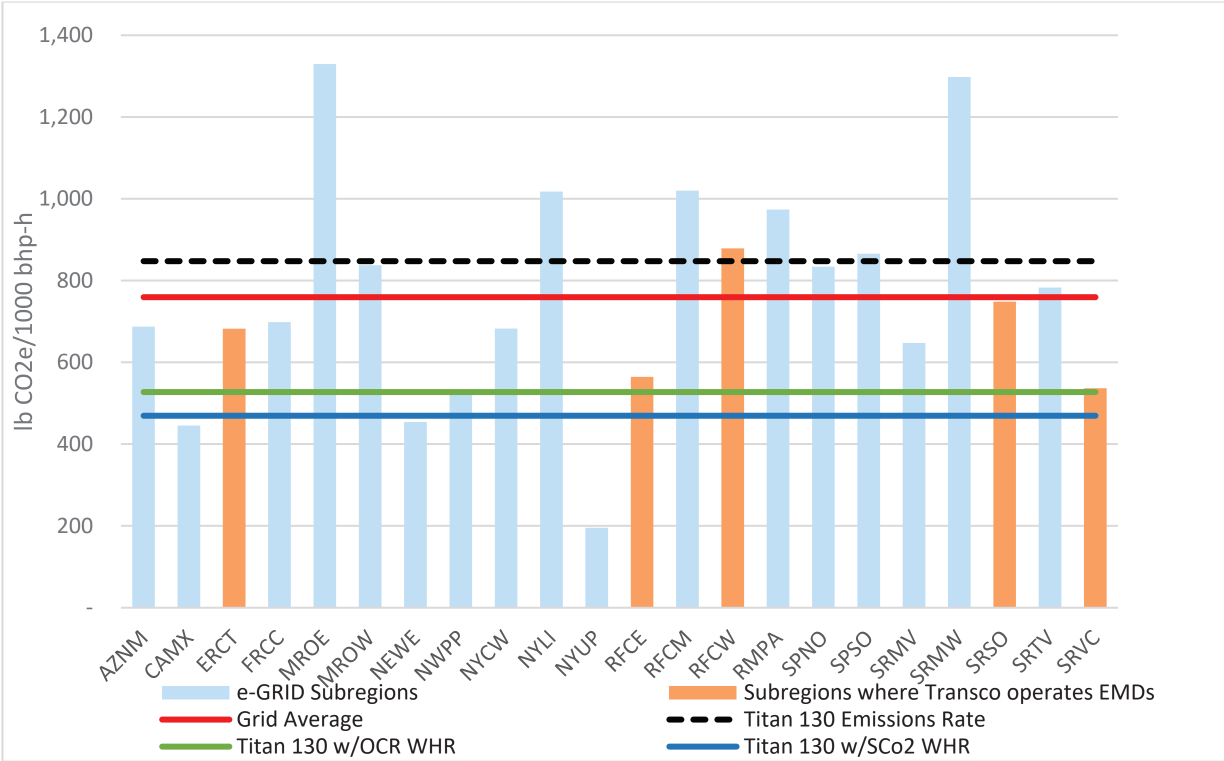

Figure 10. Scope 2 Emissions vs. Titan 130 Emissions with WHR

Figure 10 shows that commercially available ORC technologies can theoretically reduce Scope 2 emissions by 38%, allowing the Titan 130 to produce fewer emissions than all but three of the grid regions. If the higher efficiency sCO2 performance is considered, the Titan 130 with sCO2 WHR emissions rate is further reduced by 11%. Despite these theoretical GHG reductions, operating condition variability and uncertain future equipment utilization rates make it difficult to predict the economic feasibility of a WHR system. The ideal WHR station would have electric compression installed at the same location as the gas-driven compression, but even this local end-user setup comes with problems. If the turbine driven compression is online but the electric driven compression is offline, the WHR system will have no user; if the turbine driven compression is offline, the WHR system will also be offline.

Cost

Construction and installation costs are difficult to isolate based on driver type due to the multitude of factors affecting the cost of each individual project. To maintain simplicity, this analysis considered the cost of electricity itself as representative of possible cost fluctuations due to EMD utilization (Figure 11).

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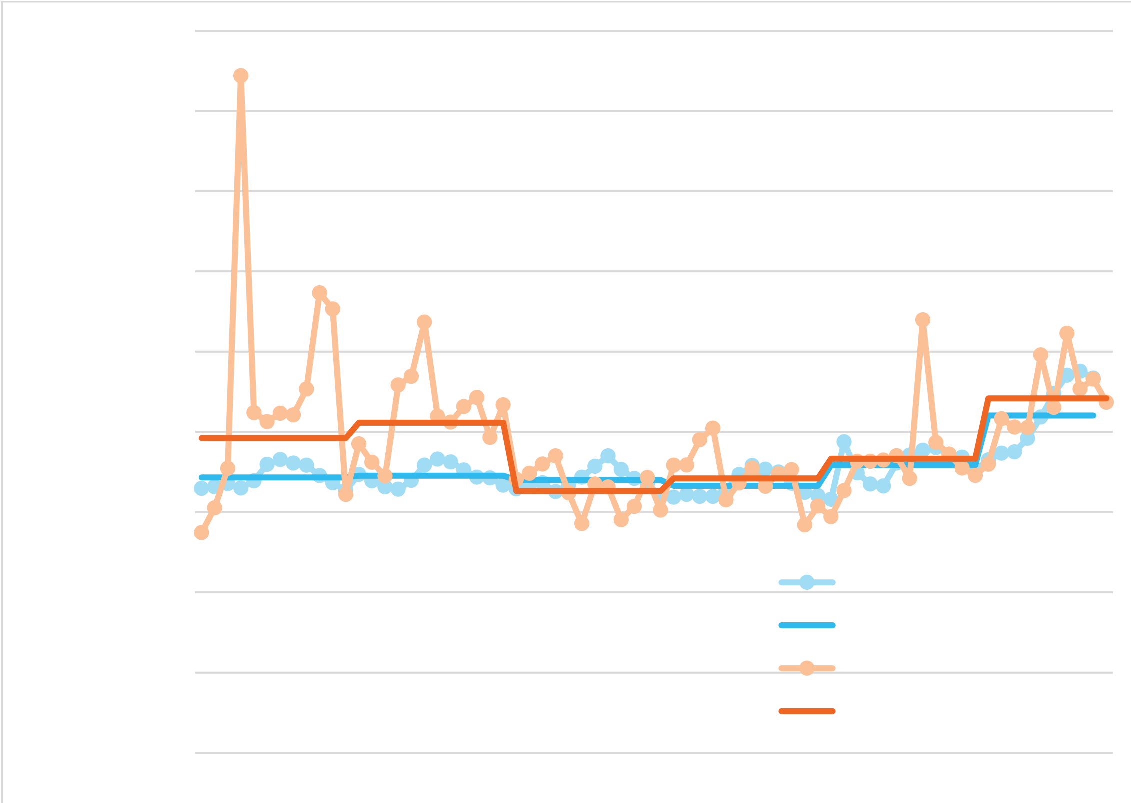

Figure 11. Cost of Electric Power ($/MWh) 2017-2022

The blue data set represents EIA historical average electricity prices while the orange represents actual electrical costs incurred by Transco. The pale lines-with-markers for each data set represent monthly averages while the dark smooth lines represent averages for each year. As there is both a demand and commodity component to the cost of electric power, seasonal usage of EMDs can describe some of the higher variability in the calculated EMD rate. Beginning in 2019, there is a clear upward trend in the annual average cost of electric power. This cost is directly passed onto ratepayers in a ratemaking mechanism known as a Transmission Electric Power (TEP) rate, which is a part of the price paid by consumers that directly provides for electric power used for EMD and gas cooler operation.

Using these actual costs of electricity, EMD operation can be compared to other methods of combustion GHG mitigation, such as hydrogen blending in fuel gas. Using the average price of electricity in 2021 from Figure 11, the average 2021 Henry Hub price of gas, and the DOE's average price of hydrogen (Appendix D), the cost differences between hydrogen and electricity as motive

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forces can be analyzed.[6] Figure 12 illustrates this comparison in the fifteen subregions in which operating an EMD is less carbon intense than operating a turbine.[7]

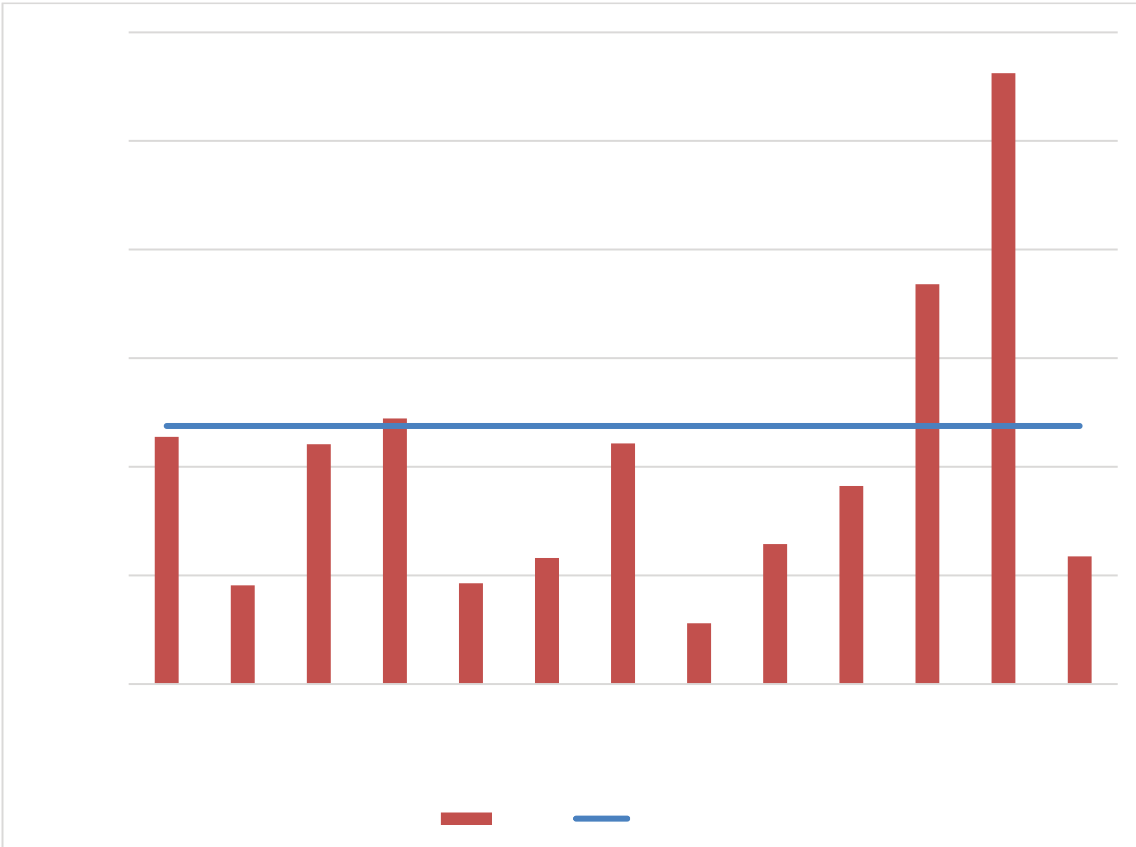

Figure 12. Cost Effectiveness of 20% Hydrogen Fuel Gas Blend vs. Cost Effectiveness of Regional EMD

A 20% hydrogen fuel gas blend is a more cost-effective emissions reduction strategy than the use of an EMD in 33% of subregions analyzed. Figure 12 suggests that further investment and research in hydrogen technologies could provide a greater emissions reduction opportunity than if that investment were limited to electric compression.

While hydrogen blending lends itself to a direct commodity cost comparison, post combustion carbon capture and waste heat recovery require a different analysis. For these technologies, it is more valuable to understand at what cost they become competitive with EMDs as a GHG mitigation strategy. As seen in Figure 12, the cost-effectiveness of EMDs varies from \$0.11/lb CO_2e mitigated to \$1.12/lb CO_2e mitigated, averaging at \$0.40/lb CO_2e mitigated. If the cost of operating PCCC

6 This comparison considers only the direct cost impacts of hydrogen and electricity as power sources. Other related costs, such as equipment, fuel delivery infrastructure, training, et cetera are not considered.

7 The SPNO and MROW subregions were considered outliers and omitted from this analysis, although they were more carbon intense than the Titan 130. An EMD in these regions was nearly ten times less cost effective than the second least cost-effective subregion.

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and WHR systems falls below $0.70/lb CO_2e mitigated, these pathways will be better investments from a GHG mitigation standpoint than electrification.

Reliability

Electric motors and gas-fired turbines operate with a certain level of unreliability due to the inevitable failure of mechanical components. The more moving parts present in a machine, the more likely it is to fail. EMDs, operating with far fewer moving parts than gas turbines, are therefore more reliable from a mechanical perspective. However, when considering electrifying gas compressor stations, it is important to consider the wider bulk power system reliability. Concerns about reliability at gas-fired facilities are typically localized and controllable by the operator. This is because the equipment's required fuel is also the fuel being transported by the compressor station – if gas is flowing through the station, fuel is available. In the event of a component failure, the operator may have spare parts or the ability to redirect loads to other available units. While operating and managing a gas-fired compression facility requires electrical power, in the event of a power outage, onsite generators can support a turbine's electrical systems. In contrast, fully electric facilities depend on third-party generators to supply the power necessary for gas compression. If there is a power outage, the operator may have little choice but to wait for electricity to be restored. This reliance on external fuel sources exposes operators to an inherent risk. Recent large-scale grid failures, such as those caused by Winter Storm Uri, demonstrate the dangers of further enmeshing natural gas and power generation infrastructure. The North American Electric Reliability Corporation (NERC) assessed the reliability of the bulk-power system in the 2022 Long Term Reliability Assessment (LTRA) and produced findings that argue that the grid could not support electrifying critical natural gas infrastructure at scale. The LTRA identifies areas at risk of supply shortfalls, categorized by high and elevated risk (Figure 13). Areas shaded in grey were not found to be at an increased reliability risk.

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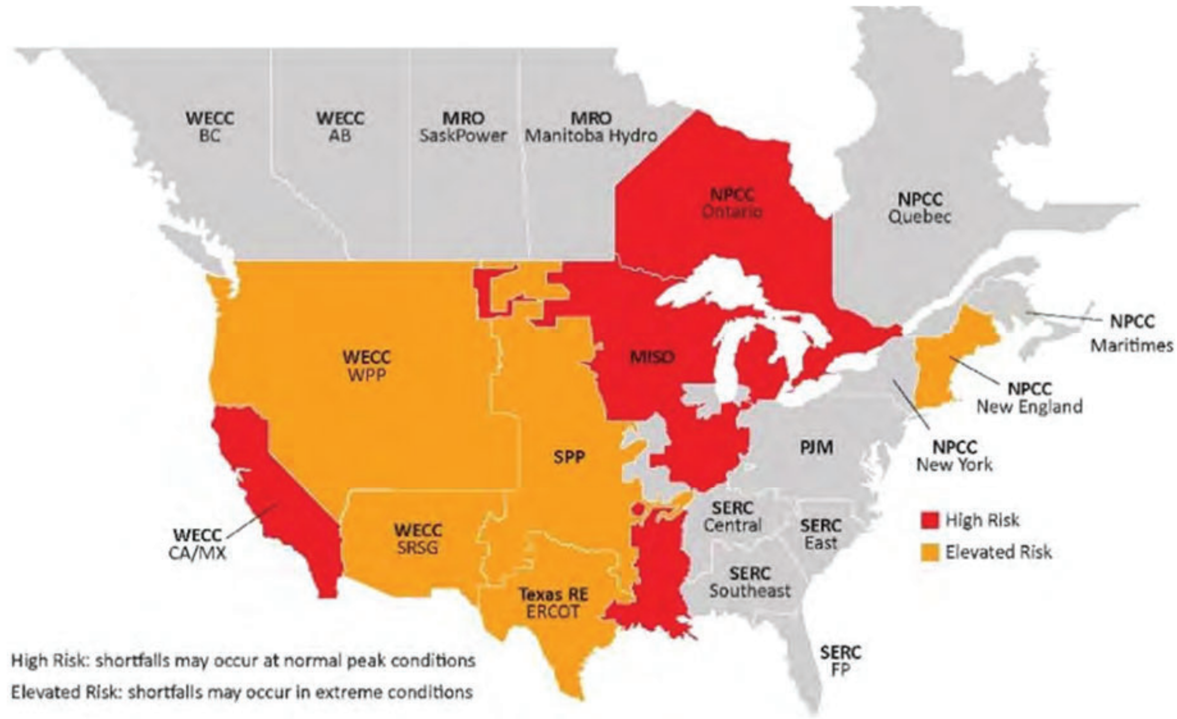

(NERC, 2023)

Figure 13. Risk Area Summary 2023-2027

The MISO area is deemed high risk, while WECC and ERCOT fall into an elevated risk category, as per the LTRA. The report cites numerous factors that contributed to the increased reliability risks in these regions. Specifically, it highlights a growing dependence on variable energy resources (VERs), such as wind and solar, without adequate investments in reliability as a significant source of risk. NERC recommends the installation of more stable forms of power generation, such as natural gas, as a supplementary source of generation for VER units, emphasizing the importance of reliable transmission of natural gas. This recommendation implies that natural gas plays a crucial role in the grid's ability to meet demand. Connecting the grid and gas compression with the installation of EMDs undermines natural gas's ability to support VERs.

Although NERC did not identify PJM as high risk, in February of 2023 PJM conducted an assessment on their system reliability. They recognized that demand for electricity has become inelastic; it is an indispensable commodity and therefore does not respond to price fluctuations. Electricity demand will continue to grow regardless of price signals, especially due to the electrification of other economic sectors and the proliferation of high-demand customers such as data centers. Despite growing inelastic demand, thermal generators in PJM are retiring at a rapid pace due to policy changes. These retirements are at risk of outpacing the development of added resources. Even if new resources manage to keep pace with retirements, resources in development are primarily intermittent and limited-duration resources. PJM concluded that if current trends continue, they will face decreasing reserve margins for the first time in years. The electrification model used by PJM does not account for the possible widespread electrification of compressor stations that represents additional demand growth (PJM Interconnection, 2023).

Furthermore, in October 2023, FERC granted approval to a proposal by PJM Interconnection LLC to establish a new classification for "fuel-assured" black-start generators capable of restoring the transmission system following a widespread blackout. Under PJM's tariff structure, compensation is provided to black-start resources—units capable of initiating operation post-blackout without external electric supply or sustaining operation when disconnected from the grid. PJM sought to introduce a distinct category for black-start units categorized as "fuel-assured" through this proposal. According to the outlined criteria, black-start units are deemed fuel-assured if they can independently operate for 16 hours without relying on grid-supplied power. Natural gas-fired units lacking on-site fuel storage would qualify as fuel-assured, provided the facility is connected to two interstate pipelines or has a direct link to a gas-gathering system (S&P Global Community Insights, 2023). PJM's proposal extended its scope to include intermittent and hybrid resources, such as solar-plus-storage facilities, as eligible fuel-secure black-start units. However, these resources would only receive compensation at a megawatt level that is 90% certain to be sustained for 16 hours based on the unit's historical performance. The primary objective of these tariff adjustments was to ensure an adequate number of power generators capable of jump-starting PJM's power grid in the event of a widespread outage. This decision reflects an acknowledgment of the reliability of natural gas as a fuel source in ensuring the availability of power during critical situations, especially compared to intermittent sources like solar or storage facilities. The aim is to address potential vulnerabilities in fuel supplies, with the recognition that natural gas can provide a more consistent and dependable source of power in black-start scenarios.

Fully electric stations create a coupled system, wherein natural gas pipelines that supply fuel to the power generation industry are dependent on the power generation industry for operation. This coupling is exacerbated if a natural gas power plant is solely supplied by a fully electrified compressor station. Figure 14 provides a simplified illustration of the most dramatic example of natural gas and electricity system coupling.

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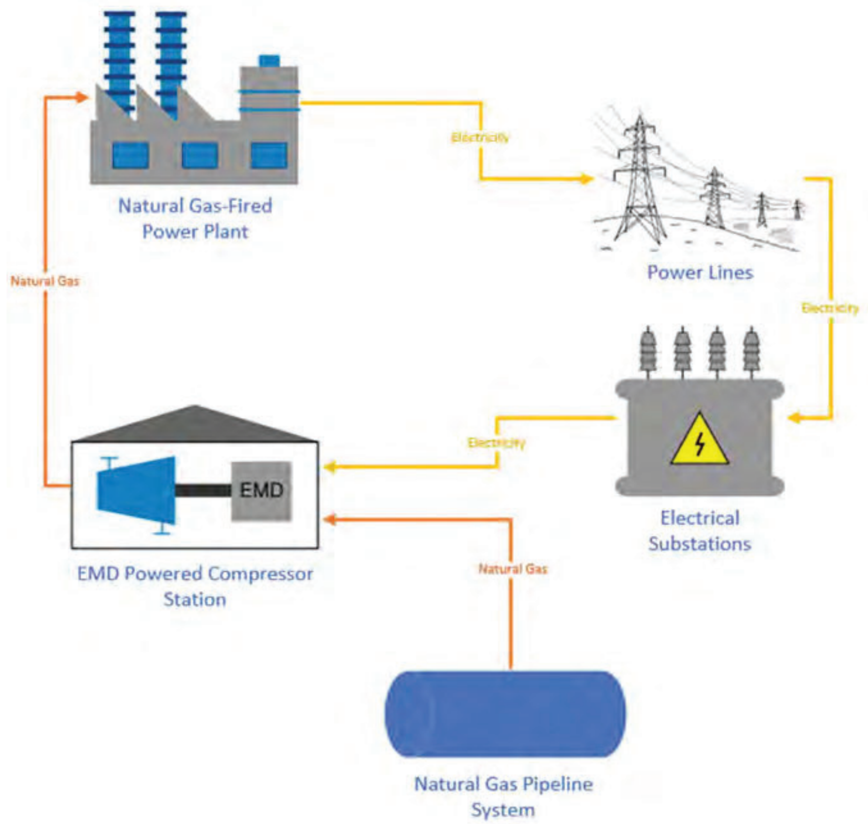

Figure 14. Natural Gas and Electricity System Coupling

In this example, the power generator consumes gas from the compressor station while simultaneously acting as the motive force for that same gas compression. The powerplant, powerlines, and substation all represent individual points of failure, which create compounding risk for electrical compressor station operation. For example, if the electricity transmission infrastructure experiences a weather-related failure on transmission lines, the compressor station could experience a cessation of electric power for compression. If the station cannot compress gas, the powerplant would lose access to natural gas fuel and would be unable to operate. After the weather-related failure is rectified, the entire system is forced to recover simultaneously, an event known as a black start.

The February 2021 cold weather outages in Texas are illustrative of this point. In a staff report, FERC remarked that gas pipelines were overall able to meet transportation agreements despite systemic disruption across the value chain in part because “most have gas-fired compressors, redundant compression, and backup power” (Federal Energy Regulatory Commission, 2021).Unfortunately, the production segment experienced much higher disruption due to electric power outages. 23.5% of natural gas production decline was caused by loss of power supply, primarily because load shed plans did not identify production facilities as critical infrastructure. This contributed to a compounding outage effect that contributed to the extended periods Texas residents went without power. If the transmission segment had been similarly affected by power outages, it would likely have necessitated

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further load shedding, as well as increased the system's overall recovery time, potentially further endangering lives.

In 2017, NERC published the Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System. This special assessment further details the risks of coupling by explaining how most natural gas-fired generation relies on "just-in-time" fuel delivery[8] (National Electric Reliability Council, 2017). Disruptions in fuel delivery can lead to generating units becoming unavailable, further emphasizing how this coupling risk is magnified by multiple plants being connected to the same natural gas infrastructure. To help quantify this risk, NERC gathered and compiled the number of generators in different regions of the U.S. that rely on only one natural gas provider.

Table 3. Region Make Up of Generators with Only One Natural Gas Connection

Region	Number of Generators with One Connection	Generation Capacity with One Connection (MW)	Total Gas Generation by Region (MW)	% Total Gas Generation with One Connection
Northwest	16	4,963	70,804	7.01%
Southern California and Arizona	20	11,430	92,054	12.42%
East Texas, Louisiana, and Oklahoma	40	17,965	120,187	14.95%
Southeast	68	46,124	87,225	52.88%
Florida	38	31,049	72,574	42.78%
Middle Atlantic	22	12,244	81,691	14.99%
New England	35	13,103	26,020	50.36%
Northeast	49	21,903	162,853	13.45%

(National Electric Reliability Council, 2017)

Table 3 demonstrates the interconnectedness and interdependence of natural gas and power generation infrastructure. In New England and the Southeast, for example, over fifty percent of all gas-fired generation is reliant on singular gas connections. These gas connections would therefore need to operate with extremely high levels of reliability as they constitute a single point of failure for

8 "Just-in-time" fuel delivery refers to the delivery of fuel to a power plant precisely when it is needed to generate electricity, rather than the plant storing fuel quantities on site. This requires high levels of coordination between the power plant and fuel suppliers.

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that generator. Generator- and plant-level failures can contribute to larger outages when the balance of grid supply and demand is disrupted, triggering automatic shutdowns or load-shedding mechanisms that are designed to prevent widespread grid failure.

In March 2023, researchers at Carnegie Mellon University produced new hydraulic models showing that "disrupting power to a single compressor station can force a loss greater than 2 gigawatts (GW) of downstream gas generators" (Smillie, Granger Morgan, & Apt, 2023). Disruptions at this level are as large, and in some cases larger, than the single-cause contingencies utility operators currently consider when assessing system reliability. Past outage events demonstrate the bulk-power system's vulnerability to compressor station failure. The Carnegie Mellon researchers use one such past event, the Pennsylvania polar vortex of 2014, to validate their hydraulic model. In its investigation into the 2014 outages, NERC identified one compressor station outage as being responsible for 15% of the outages experienced in the affected region. This study further identified the responsible station as a mixed-drive station, using both gas and electric drivers, demonstrating the reliability concerns associated with electrification of compressor driver horsepower.

As commercial services and industries modernize, more applications are hosted on cloud services and more data is stored, configured, and processed in large off-site locations called data centers. These data centers are large facilities that house the necessary IT infrastructure to build, run, and deliver critical applications and services. Since many industries integrate these data centers into their services, these data centers are considered "mission critical", requiring that these facilities be highly reliable and have little downtime. In 2022, there were 2,702 data centers in the United States or over 42% of the data centers worldwide. The Berkeley Lab estimated that these data centers consumed 73 billion kilowatt-hours in 2020, only being outpaced by residential use in Texas, Florida, and California. In the US market alone, demand—measured by power consumption to reflect the number of servers a data center can house—is expected to reach 35 GW by 2030, up from 17 GW in 2022 (McKinsey & Company, 2023).

Due to the nature of the data and the applications that are hosted at these data centers, data centers and their customers have established thresholds for service interruptions in the form of service-level agreements. Customers can obtain agreements to have from 29 hours to as little as 27 minutes of service interruption each year (Arbo IQ, 2023). This requires the data centers to not only have strict operating methods but also reliable and constant sources of power. Most data centers source their power from a utility transmission system with established reliability standards in addition to having backup power agreements, but data centers are increasingly constructing on-site power generation to protect against service interruptions. Natural gas is the fuel generally relied on for these on-site power generation facilities.

As the number of data centers in the US increases, the reliability of the electrical grid, power generation facilities, and fuel providers becomes increasingly important. The critical nature of data centers increases the severity of having a coupling failure described in Figure 14. A coupling failure

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or a grid failure due to the failure of an electrical compression station could cause data centers to go offline, severely impacting the customers and public relying on the services provided by data centers.

National Security

Risks to grid operability do not stop at weather-related outages. In 2021, a foreign ransomware attack on Colonial Pipeline's systems caused widespread gasoline shortages across the east coast. In response, the Transportation Security Administration (TSA) produced updated cybersecurity requirements for pipeline operators. Although the power generation segment is similarly regulated by NERC, the coupling of pipeline and power generation operations represents an increased threat to energy security at a national level. Recent global events such as Russian attacks on the Ukrainian grid have demonstrated the possibility of energy-focused attacks during times of conflict. The risk of an attack causing widespread energy deficits increases when the natural gas transmission apparatus relies on generated power to operate.

Targeted attacks that threaten the physical security of the electrical grid have become more prevalent over the last decade. In December 2022, 45,000 people in North Carolina were left without power due to gunfire attacks on two substations. That same month, on Christmas Day, two men attacked substations in Washington state, leaving thousands without power. According to the Department of Energy's 2022 Electric Disturbance Event summary, 162 reported disturbances were caused by vandalism, physical attacks, and "suspicious activity[9]," representing about 40% of all reported disturbance causes (Table 4).

9 "Suspicious activity" can include people taking photos of energy infrastructure, or people or drones approaching facilities unannounced

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Table 4. Emergency Disturbance Events by Type and NERC region

NERC Region	Event Type	Total
MRO	Actual Physical Attack	2
	Vandalism	4
MRO Total		6
NPCC	Actual Physical Attack	1
	Suspicious Activity	9
	Vandalism	4
NPCC Total		14
RF	Actual Physical Attack/Vandalism	1
	Suspicious Activity	19
	Vandalism	2
RF Total		22
SERC	Actual Physical Attack	3
	Actual Physical Attack/Vandalism	3
	Suspicious Activity	8
	Vandalism	12
SERC Total		26
SERC/RF	Suspicious Activity	1
SERC/RF Total		1
TRE	Actual Physical Attack/Vandalism	1
	Suspicious Activity	11
	Vandalism	5
TRE Total		17
TRE/SERC	Vandalism	3
TRE/SERC Total		3
WECC	Actual Physical Attack	9
	Actual Physical Attack/Vandalism	5
	Suspicious Activity	9
	Vandalism	50
WECC Total		73
Grand Total		162
All Disturbances Total		389

(NERC, 2022)

In 2006, NERC developed the Critical Infrastructure Protection (CIP) standards in response to a growing threat of cyber-attacks on the North American grid. However, because of the vast "hub-and-spoke" nature of the power delivery system, an individual substation may support entire communities full of critical consumers without falling subject to the CIP standards. Often, these subcritical substations operate in rural areas – the same areas in which compressor stations are most often found. The feedback loop described in Figure 14 does not only apply to weather-related events; it holds true during physical or cyber-attacks that cause an outage. Electrifying compressor stations without first properly fortifying the grid against attacks amplifies undesirable attack outcomes. For example, if multiple transformers are destroyed at a substation that serves a compressor station, the loss of compression could lead to cascading electrical outages across the area, making it more difficult to recover from the attack.

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The attacks outlined in Table 4 do not account for any cyber-related threats, which present additional vulnerabilities for all utility systems. In 2016, the Department of Energy conducted a vulnerability analysis of the U.S. electric sector, which assessed multiple cybersecurity risks throughout the electricity value chain. The analysis revealed that threat actors have become more sophisticated, and that the proliferation of interoperable technologies[10] has increased vulnerabilities throughout the U.S. system (U.S. Department of Energy, 2016). While most cyber-attacks involve data breaches where critical or sensitive information is stolen from an entity, other attacks can modify an entity's computer systems to cause physical changes to their equipment. Both types of cyber-attacks can cause significant damage but attacks that can impose physical changes on operating equipment have the potential to affect not only the victim, but related parties and downstream consumers. The 2021 cyberattack on Colonial Pipeline is a prime example of a successful targeted attack that affected the physical operation of equipment, resulting in the forced shutdown of several of Colonial's pipelines. This caused delays and setbacks for airports relying on kerosene from Colonial's pipelines, while gasoline and diesel consumers experienced large price increases due to fuel shortages.

When considering electric compression, the probabilities of a successful targeted cyber-attack that results in a loss of compression is comparable between an electric and natural gas-fired compression station, but the severity varies significantly. Both types of compression have Programmable Logic Controllers (PLCs) with a similar probability of being hacked. The difference in severity arises from the interconnectivity of each type – an electrical station will fail if a threat actor successfully disrupts an electrical generator's cyber systems while a gas station will not. The attack surface, or the sum of different points at which threat actors may infiltrate the software environment, effectively increases when a station is electrified because a greater number of attack points can result in a breakdown of the energy value chain. The Department of Energy's vulnerability analysis also found that, as smart grid technology is adopted and the complexity of the electrical grid increases, more measures will need to be adopted to ensure adequate protection from cyber-attacks. It further identifies each piece of the electricity value chain as having its own vulnerabilities, which exponentially increases the possible threat output of any single point of failure. It can be reasonably concluded then that furthering the interdependence of the grid and natural gas systems will further increase the vulnerabilities of both systems (U.S. Department of Energy, 2016).

Not only does the number of available access points increase with widespread EMD installation, but threat actors experience increased mobility across software systems. Lateral movement describes a threat actor's ability to avoid detection and retain access, even after discovery on the initial access point. Below is a thorough description of an attack scenario amplified by the electrification of a station.

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10 Interoperability describes the ability of systems to connect and communicate without effort from the end user. In this context, this can include automatic load-shedding schemes and settlement calculation software, for example.

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1) **Initial access:** an attacker obtains access to an electric utility's intranet through a phishing attack.
2) **Persistence:** the attacker discreetly maintains access despite system restarts or changed passwords.
3) **Discovery:** the utility discovers the data breech, but the attacker has maintained access long enough that the threat can no longer be contained.
4) **Lateral movement:** the attacker uses the initial access to gain further access to other parts of the utility's systems, such as SCADA systems and sensitive consumer information
5) **Objective:** in this example, the attacker's objective is to identify critical infrastructure across the electricity value chain. The attacker intends to disrupt critical equipment function to extract a ransom. Unfortunately, this utility provides electricity to multiple EMD-drive gas compressor stations. The utility and the natural gas operator have discussed critical infrastructure on both sides. The attacker can obtain the locations of this critical equipment for both companies. The attacker not only forces all utility services to halt, shutting down the compressor stations but also exploits the location of the gas compression equipment to increase the impact of this single attack.

This is just one example of attack scenarios that evolve with widespread compression electrification in the natural gas industry. These attacks have the capacity to impact millions of people through the exploitation of a single vulnerability.

Conclusions and Recommendations

- Electric compression should be considered on a case-by-case basis by individual project teams. Analyses should be conducted on impact to local electric grid resilience, cost effectiveness of EMD installation on a GHG mitigation basis, and the reliability risk associated with an electric station. Existing heat maps provide good line of sight on cost and some aspects of reliability, but other tools are available to assist in the consideration of GHG mitigation and national security, many of which are included in the references of this paper.
- Analyses of U.S. grid reliability do not support widespread compressor station electrification. As shares of plants powered by variable energy sources such as wind and solar are expected to increase, so too are the risks to grid reliability.
- While renewable electricity generation is expected to increase, it is not expected to replace natural gas for the duration of any time horizon considered in this report. Natural gas will continue to be integral to the U.S. electricity supply and coupling the power generation and natural gas transmission segments through electrification presents challenges that must be considered.
- Electrifying compressor stations does not result in comprehensive carbon dioxide mitigation; rather, the emissions reduction potential of EMDs is highly regionalized, with

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some parts of the U.S. grid producing more emissions than gas-fired turbines on an energy output basis.

- The growth of variable sources requires supplemental fuel sources, commonly natural gas, to be available at power plants in cases when demand cannot be met. Not only does this further underscore the importance that the natural gas transmission segment operates with high reliability, but it demonstrates the extremely variable GHG mitigation effect of electrification.
- Advancing technology in hydrogen fuel, carbon capture, and waste heat recovery could mitigate combustion emissions more effectively than EMDs. Opportunities to employ multiple technologies, such as post combustion carbon capture and waste heat recovery, should be evaluated as viable paths to compression decarbonization.

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Appendices

Appendix A: Turbine Emissions Calculations

Equation A1: Turbine Emissions Rate

$$Emission\ Factor\left(\frac{lb}{(MMBtu)_{fuel\ input}}\right) * Heat\ Rate\ \left(\frac{MMBtu}{(bhp-hr)_{energy\ output}}\right)$$
$$= Emissions\ Rate\ \left(\frac{lb}{bhp-hr}\right)$$

Appendix B: Grid Associated Emissions Calculations

Equation B1: Average EMM Region Rate for a Given Year

$$Emissions\ Rate\ \left(\frac{lb\ CO_2e}{MWh}\right)_{Year} =$$
$$\frac{Gen\ for\ a\ Source\ \ Type\ (BkWh)_{Year}}{Total\ Predicted\ Gen\ (BkWh)_{Year}} * Subregion\ Source\ Emissions\ Rate\ \left(\frac{lb\ CO_2e}{MWh}\right)$$

Equation B2: MWh to bhp-h Conversion

$$\frac{lb\ CO_2e}{MWh}_{Year} * \frac{1\ MWh}{1341\ bhp-h} = \frac{lb\ CO_2e}{bhp-h}_{Year}$$

Equation B3: Grid Efficiency Calculation

$$Emissions\ Rate\ \left(\frac{lb\ CO_2e}{bhp-h}_{Year}\right)$$
$$= Emissions\ Rate\ \left(\frac{lb\ CO_2e}{bhp-h}_{Year}\right)$$
$$* \left[\left(Grid\ Eff.(\%)\right) * \left(Transformer\ Eff.^{n}\ (\%)\right) * \left(Unit\ Eff.(\%)\right)\right]$$

Appendix C: Variable Turbine Heat Rate

Equation C1: Titan 130 Heat Rate/Temperature Curve

$$Heat\ Rate = \ (-9.78 \times 10^{-10} * T_o^6) + (2.11521 \times 10^{-7} * T_o^5) - (9.31983210^{-6} * T_o^4)$$
$$- (7.098636 \times 10^{-5} * T_o^3) + (0.016929311975 * T_o^2) - (0.122048908393 * T_o)$$
$$+ 6761.68594690439$$

Where T_o = inlet air temperature as defined in Table C1

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Table C1. Monthly Average High Temperatures in °F in Major Cities Across PJM

City	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Charleston	44	48	58	69	76	82	85	84	78	67	57	48
Wheeling	38	41	52	63	72	79	83	81	75	64	53	42
Richmond	47	51	60	70	77	85	88	86	80	70	60	51
Norfolk	50	52	60	69	77	84	88	86	80	71	62	54
Arlington	43	46	56	66	75	83	87	85	78	67	56	47
Philadelphia	41	44	53	64	74	82	86	84	77	66	55	45
Pittsburgh	37	41	51	63	72	80	83	81	75	63	52	42
Erie	34	35	43	55	66	75	79	77	71	60	49	39
Scranton	34	37	47	60	70	77	82	79	72	61	49	38
Average	**40.9**	**43.9**	**53.3**	**64.3**	**73.2**	**80.8**	**84.6**	**82.6**	**76.2**	**65.4**	**54.8**	**45.1**

Appendix D: Cost Effectiveness Calculation

Table D1. Prices of Natural Gas and Electricity in 2021

2021 Average Henry Hub Natural Gas Spot Price	2021 Average Electricity Price Paid by Transco
\$13.48 (\$/MWh)	\$73.32 (\$/MWh)

$$Cost\ of\ Hydrogen\ per\ MWh = \frac{\$2.27}{lb_{H_2}} * \frac{192\ lb_{H_2}}{scf} * \frac{10^6\ scf}{325\ MMBtu} * \frac{MMBtu}{0.29\ MWh} = \$125.31\ (\frac{\$}{MWh})$$

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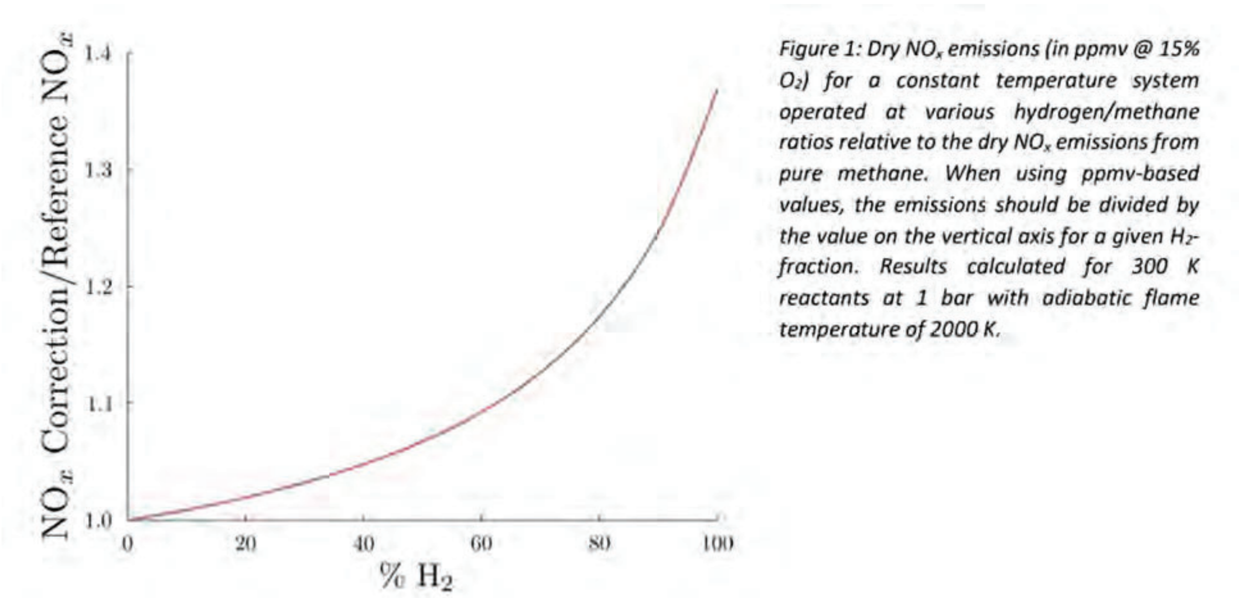
Appendix E: Hydrogen Blending in Turbines

Table E1. Hydrogen Blended Fuels Impact of CO2 Emissions Estimates – Caterpillar

	0% H2	5% H2	10% H2	15% H2	20% H2	30% H2	40% H2	50% H2	60% H2	70% H2	80% H2	90% H2	100% H2
CO_2 % Reduction Estimate		1-2%	3%	5%	7%	11%	16%	22%	30%	41%	54%	72%	100%
CO_2 Emission Factor lb/MMBtu (HHV) (kg/GJ)	117.2 (50.3)	115.3 (49.6)	113.3 (48.7)	111.1 (47.8)	108.7 (46.7)	103.4 (44.4)	97.1 (41.7)	89.4 (38.4)	79.9 (34.3)	67.9 (29.2)	52.2 (22.4)	30.8 (13.2)	

Assumptions: Full load, 59F, 60% RH, no losses, minimum performance, blended with San Diego natural gas.

(Solar Turbines, 2022)



(Georgia Institute of Technology, 2022)

Figure E1. NOx Correction for Hydrogen Blends

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