Impact of Electrifying Natural Gas Transmission Compression

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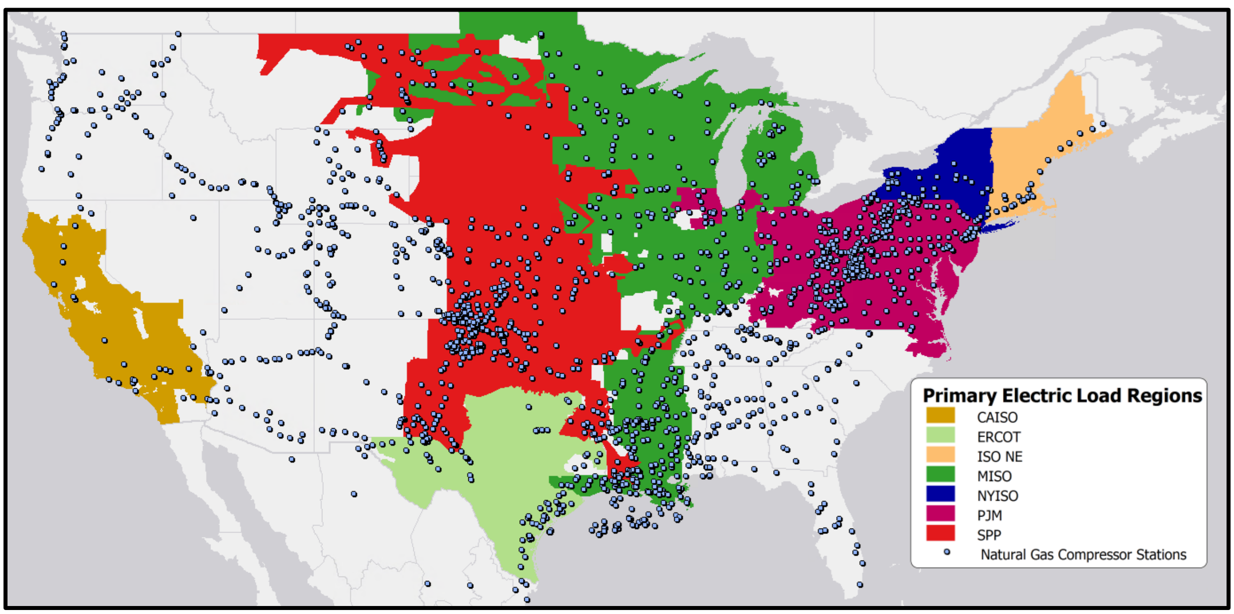
1 Executive Summary

Members of The INGAA Foundation are currently evaluating options available to reduce greenhouse gas (GHG) emissions from interstate natural gas transmission pipelines and storage facilities. This discussion is taking place in several forums and includes consideration of a variety of end-uses and technologies.

One option pipeline operators are considering is converting natural gas-fired compressor stations to electric-driven compressors to reduce GHG emissions. Switching to electric-driven compression would reduce methane emissions and eliminate combustion emissions from compressor stations, thereby reducing overall GHG emissions. However, this switch to electric motor-driven compression could raise reliability and resiliency concerns for both the natural gas transmission and power generation systems if the power supply serving those compressors is subject to disruption.

There are approximately 1,395 natural gas interstate pipeline compressor stations in the United States (U.S.) (shown in Figure 1) with slightly more than 21,000,000 horsepower (HP) total combined compression capacity.[1] Partial electrification of the natural gas transmission compression could reduce GHG emissions, but that electrification needs to be done in a way that considers impacts to the electric and natural gas grids in addition to GHG emission reduction.

Figure 1 - U.S. Independent System Operators and Interstate Natural Gas Compressor Stations Map



Source: Hitachi Energy and ICF[2]

[1] HIFLD Compressor Database: https://hifld-geoplatform.opendata.arcgis.com/datasets/geoplatform::natural-gas-compressor-stations/explore?location=36.564378,-96.043033,5.79

[2] CAISO = California Independent System Operator, ERCOT = Electric Reliability Council of Texas, ISO-NE = Independent System Operator New England, MISO = Midcontinent Independent System Operator,

While most areas of the country have access to both natural gas infrastructure and to electric grids, these systems often don't perfectly align with respect to geography, capacity, or demand. Because of this, electrifying compressor stations is more feasible in certain regions of the U.S. than in others, and within those regions more feasible in specific locations than others.

The INGAA Foundation asked ICF, through this report, to assess the current interstate gas pipeline compression capacity, the interstate gas pipelines' future capacity requirements, and the impact of converting existing gas-fired compression to be electric-driven. ICF assessed the regional impact on peak electricity demand that potential compression electrification could have using its latest forecasts and growth curves.

The INGAA Foundation also asked ICF to develop a conceptual compressor replacement plan to assess the feasibility, costs, and benefits to the interstate natural gas pipeline industry of replacing all gas-fired compressors with electric motor-driven compressors. To do this, ICF compared installation of a new electric motor-driven compressor, a gas turbine-driven compressor, and a dual electric/gas turbine-driven compressor from the perspective of capital and operating costs, carbon intensity scoring[3], and any environmental attribute credits available for each option. ICF then expanded this analysis to provide a more general roadmap that can be applied by INGAA members when considering whether to apply electrification at specific transmission compressor stations.

U.S. Natural Gas Interstate Pipeline Compression Capacity Growth

ICF forecasts that natural gas demand will grow through at least 2030, primarily driven by industrial use, power generation, and exports. The need for interstate natural gas pipeline infrastructure and natural gas pipeline compression capacity is projected increase correspondingly.

That demand growth is projected to drive the growth of interstate compression capacity for at least the next two decades. Based on ICF's database of known firm and expected pipeline projects, an additional 2,615,000 HP (for a total of nearly 24 million HP) of compression will be needed for the interstate natural gas pipeline system throughout the country between 2023 and 2029. That represents a more than 10% increase in interstate natural gas pipeline compression capacity requirements in that time frame.

To meet demand across all sectors beyond the 2029 peak and 2045, ICF forecasts natural gas compression capacity requirements in each electric independent system operator (ISO) and regional transmission organization (RTO) region (shown in Figure 1) will increase or remain close to 2029 levels. Peak day and peak month utilization, and thus peak period compression requirements are projected to increase faster than the annual average. As a result, existing interstate natural gas pipeline compression, whether gas-fired or electric-powered would still need to be retained for the duration of the forecast horizon. Peak day pipeline utilization, which drives

NYISO = New York Independent System Operator, PJM = Pennsylvania-New Jersey-Maryland Interconnection, SPP= Southwest Power Pool

[3] Carbon intensity scoring determines the amount of carbon dioxide (CO2) released to produce a kilowatt hour (kWh) of electricity.

energy system planning, in all ISO/RTO regions at times reaches 100% which means meeting any additional demand would require additional compression capacity.

U.S. Natural Gas Compression Requirements' Effect on the ISOs/RTOs

Based on this study's analysis of the peak electricity requirements resulting from potentially electrified interstate natural gas pipeline compression, ICF expects there to be areas in the U.S. where the impact of electric compression on regional and local electricity transmission systems would require incremental investment in electricity transmission capacity.

Of the total current U.S. interstate natural gas transmission natural gas-fired compression capacity, 75% falls within the MISO and PJM regions. If all of the gas-fired compressors in those ISO footprints are converted from natural gas to electricity, the compression capacity in these regions has the potential to increase peak electric load by almost 8,000 megawatts (MW), which would increase the forecasted peak electric load growth between 2022 and 2030 for those regions by more than 50%.[4]

In the three ISOs with the largest peak demand requirements – PJM, MISO, and ERCOT – the additional electrical generation and transmission infrastructure required to meet the additional demand likely would require significant development time and investment. This demand growth also could occur at the same time as other sectors push to electrify traditionally fossil applications, such as electric vehicles or electric heating. The power infrastructure requirements may be further expanded with additional backup generation to ensure reliability and resiliency of electric compressors in the event of grid outages.

The potential added electricity demand from converting gas-fired compressor stations to electric motor-driven compressor stations could increase the 2030 peak-demand growth as currently forecasted. For example, electrifying all gas-fired compression in NYISO could cause an increase from the current (2022) forecasted change in electricity peak demand between 2023 and 2030, -334 MW (reduced demand), to an increase of 84 MW. ERCOT and CAISO have less pronounced increases, but the concentration of demand increases in sub-geographies within the ISO could place stress on electric transmission and distribution systems in these sub-geographies.

As stated above, this study focuses on the potential impacts on regional and state peak electricity demand because it drives electric power infrastructure planning. Additionally, understanding the effects of electrifying compression on sub-state and local demand, and the effects on seasonal and hourly electric load, will be critical for understanding the impact of compressor electrification. For example, an electric grid located near a compressor station is expected to have a much higher percentage of peak demand occupied by additional electric compression. If compression power demand aligns with heating end uses, the peak from both could combine to elevate the electric needs.

Natural Gas Transmission Compressor Conversion Assessment

After assessing the forecasted growth of the natural gas interstate pipeline compression requirements and the potential impact on power demand of converting interstate natural gas

[4] 1,000 HP = 0.75 MW. Compression HP was converted to capacity in terms of MW in order to assess the impact of converting compressor stations to be electric-driven on the electric grid.

pipeline compressors to be electric-driven, ICF assessed the replacement of three existing natural gas internal combustion engine-driven/2-stroke reciprocating gas compressors that are close to end of their useful life. This assessment was included in this report to better understand the obstacles and incentives associated with electrification of gas transmission compressor assets. Natural gas-driven reciprocating compressor(s) were selected for replacement because they are the most common type of compressor on a gas transmission system. ICF assessed replacing the compressors with either a new single electric motor-driven (EMD) centrifugal compressor, gas turbine-driven (GT) centrifugal compressor, or a dual-driven (EMD and GT) centrifugal compressor.

ICF considered the capital costs, operating costs, carbon intensity scoring, and environmental attribute credits available for each project option to provide general guidance on electrification of natural gas compressor stations. The results of the economic pro forma modelling are dependent on forecasted electricity and natural gas prices. For this scenario, ICF's outlook for the eastern Pennsylvania region shows future electricity prices will be low enough to make the EMD compressor option less expensive to operate than the gas turbine compressor, given the other factors included in the financial analysis. This may be true in eastern Pennsylvania but not necessarily true elsewhere in the U.S.

The assessment determined that at some compressor stations, installation of dual-drive compression can achieve significant GHG reductions versus installation of equivalent natural gas only-driven compressors, while not adversely impacting the reliability and resiliency of the natural gas transmission system, at a relatively small increased lifecycle cost. In this case, both the higher capital and energy cost of the dual-drive compressor can be partially offset by the dual-drive compressor's flexibility to operate on natural gas during peak power cost periods and by reduced annual maintenance costs versus gas turbine (only) driven compressors.

Roadmap for conversion of compressor stations

The end of their service life is an opportune time for operators to consider replacing an older, natural gas driven compressor with one that is electric motor driven. Further, an assessment of the potential adverse impacts on the reliability and resiliency of the gas transmission (and electric system), such as the potential for electric power outages, must always be examined as part of compressor electrification.

ICF included two representative frameworks that will support the development of an electrification strategy for a natural gas pipeline operator. It is worth noting that electrification may not be a universally applicable solution. As such, these frameworks are intended to be synergistically employed, enabling natural gas pipeline operators to judiciously determine the optimal timing and approach for electrifying their compressor stations within their asset portfolio.

The first framework, the corporate electrification framework provides a strategic blueprint for pipeline operators, enabling them to scrutinize their current portfolio and identify the largest opportunities for electrification using a scoring matrix. This analysis is driven by three focal point: first, electrification with the overarching corporate objectives, second, by prioritizing capital projects, and last, by capitalizing on methane reduction underpinned by external variables and legislative opportunities.

The site-specific electrification decision framework is designed to help natural gas pipeline operators navigate how to develop a candidate compressor station identified for electrification. This framework prioritizes: (i) the grid interconnection, (ii) gas transmission resiliency and (iii) permitting. As these factors can introduce long-term risks and can introduce development delays, it is critical to have a clear line of sight in resolving concerns prior to further investments.

2 Introduction

The INGAA Foundation commissioned ICF to develop a study that evaluates:

1. the potential impacts of widespread electrification of interstate natural gas transmission compression on electricity demand and to provide an initial assessment of the potential impacts of this demand growth on the electric grid and
2. the electrification of an existing gas transmission compressor station to compare electric motor-driven compressors, gas turbine driven compressors, and dual electric/gas turbine drives from the perspective of capital and operating costs, carbon intensity, and any environmental attribute credits.

ICF's conclusions from this specific analysis will be expanded to provide a more general roadmap that pipeline operators and policymakers can utilize when considering electrification at specific gas transmission compressor station locations.

2.1 Objectives of this Study

The key objective of this study is to evaluate the impacts of converting interstate natural gas pipeline natural gas-fired compression to electric-powered compression. This study examines the potential impact of the conversion to electric compression on peak electricity demand. This study includes a review of the load requirements of electrifying all compression equipment in the U.S. interstate natural gas transmission network, and an assessment of the capacity of the electric grid to absorb this additional load. This study also considers seasonal demand for both natural gas and electric load requirements, including during extreme weather events such as Winter Storm Uri in February 2021.

In addition to the nationwide assessment, ICF evaluated electrifying a candidate compressor station and analyzing both the capital and operating costs of three compressor drive options and considered carbon intensity scoring and environmental attribute credits available. The findings from the evaluation were used to develop frameworks for interstate natural gas pipeline companies.

2.2 Methodology

To evaluate the impact of converting the gas-fired compressor stations on the interstate natural gas pipeline system to use electricity for their energy supply, ICF conducted a three-step analysis that included:

- A technical review of the use of natural gas compression in the interstate natural gas pipeline industry. The review was based on ICF databases and forecasts, public databases, and on input from the natural gas pipeline industry.
- A technical review of the impacts on electric load of converting gas-fired compression to electric compression.
- A qualitative assessment of the impact of the increase in electricity requirements on the electric grid. This assessment addresses the theoretical implications of electric load growth on electric grid infrastructure requirements, as well as the implications of reliance on the electric grid to power the natural gas system, and the interrelationship between

these two impact components.

To evaluate the selection and impacts of electrification on a candidate compressor station, ICF applied the following technical and commercial methodologies:

- Determination of a key focus region for this study. An ISO/RTO region was scored based on metrics including grid reliability, density of compressor stations, grid power carbon intensity score, power cost, grid congestion, and compression demand growth. The region with the highest score was chosen as a key focus region for this study.
- Selection of possible candidate compressor stations across the key focus region to determine a potential single compressor station for electrification. This evaluation included a variety of factors, which includes the local grid power carbon intensity score and the proximity of the gas-fired compressor station to the electric transmission grid.
- Review of selected compressor stations for replacement with one new centrifugal compressor with either (i) an electric motor drive (EMD), (ii) a gas turbine (GT) drive, or (iii) a dual EMD/GT drive.
- Incorporation of a compressor vendor's performance, equipment cost, and maintenance cost information for one new, replaced, centrifugal compressor, with the three drive options.
- Completion of an economic (life cycle) analysis of each compressor option, based on the data received from the compressor vendor. The economic analysis considers any available environmental attribute credits.
- Calculation of a carbon intensity score for each compressor drive option using the latest version of the Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) model developed by the Argonne National Laboratory to understand the beneficial carbon impact of electrification.
- Development of a generalized set of recommendations when considering electrification of a specific asset based on a summary of the analysis described above.

This study focuses on three time periods, the natural gas compression needs today, in the near term (in the next six years), and in the long term (between now and 2045[5]). ICF relied on its own data and on public data sources, to create the framework needed to portray the role of natural gas and natural gas infrastructure in the future. This study only analyzes the interstate natural gas pipeline system and does not analyze natural gas compression on the intrastate pipeline system or distribution systems.

[5] ICF’s Q3 2023 base case natural gas market forecast horizon for the U.S. is through 2045.

3 Assessment of Energy Demand from Electrical Compression

This section summarizes the current size of the interstate natural gas compression requirements and uses ICF's Q3 2023 base case North American natural gas markets forecast to estimate future interstate pipeline compression requirements. This analysis uses the U.S. Department of Homeland Security compressor database (released in December 2022), electric ISO forecasts, and ICF natural gas market data.

3.1 Natural Gas Market Forecast

The projection of compression capacity needs over the near term (next five years) and the long term (between 2023 and 2045) used in this study was based on the ICF Q3 2023 Gas Market Model (GMM) base case forecast for North American natural gas markets. While U.S. natural gas demand for domestic use and exports will continue to grow throughout the 2020s, today's existing pipeline and compression capacity will continue to comprise the majority of gas pipeline infrastructure in the U.S. for the next few decades. Additionally, the need for incremental interstate natural gas pipeline infrastructure, and thus additional interstate natural gas compression, will be driven by growing demand over the next decade for industrial/petrochemical use, power generation, and exports. Thus, the need for interstate natural gas pipeline infrastructure and natural gas pipeline compression capacity is not only projected to continue, but also grow. Peak day and peak month utilization, and thus peak period compression requirements are projected to increase faster than the annual average. As a result, interstate natural gas pipeline compression, whether gas-fired or electric-powered will still require maintenance for the duration of the forecast horizon of this study. A detailed description of current and forecasted U.S. natural gas demand can be found in Appendix B.

3.2 Near-Term Compression Capacity Requirements

To forecast the growth in compression capacity requirements for the near term and long term, ICF utilized its Q3 2023 database of historical and proposed natural gas pipeline projects to calculate the forecasted natural gas compression capacity requirements. The near-term forecast for annual compression capacity additions, which includes the compression capacity associated with the completion of known firm and expected pipeline projects is shown in Table 1. Beyond 2029, the compression capacity required on the interstate pipeline system in the U.S. will be in existence and used at roughly the same size but will still require maintenance, refurbishment, and replacement.

Table 1 - Forecasted Annual Additional Interstate Natural Gas Compression Capacity in 1000s of Horsepower

Forecasted Annual Additional Interstate Natural Gas Compression Capacity in 1000s of Horsepower		
	Additional Compression in HP or MW	
Year	**1000 HP**	**MW**
2023	917	688
2024	695	521
2025	379	284
2026	370	277
2027	120	90
2028	122	92
2029	13	10
2023-2028 Total	**2,615**	**1,961**

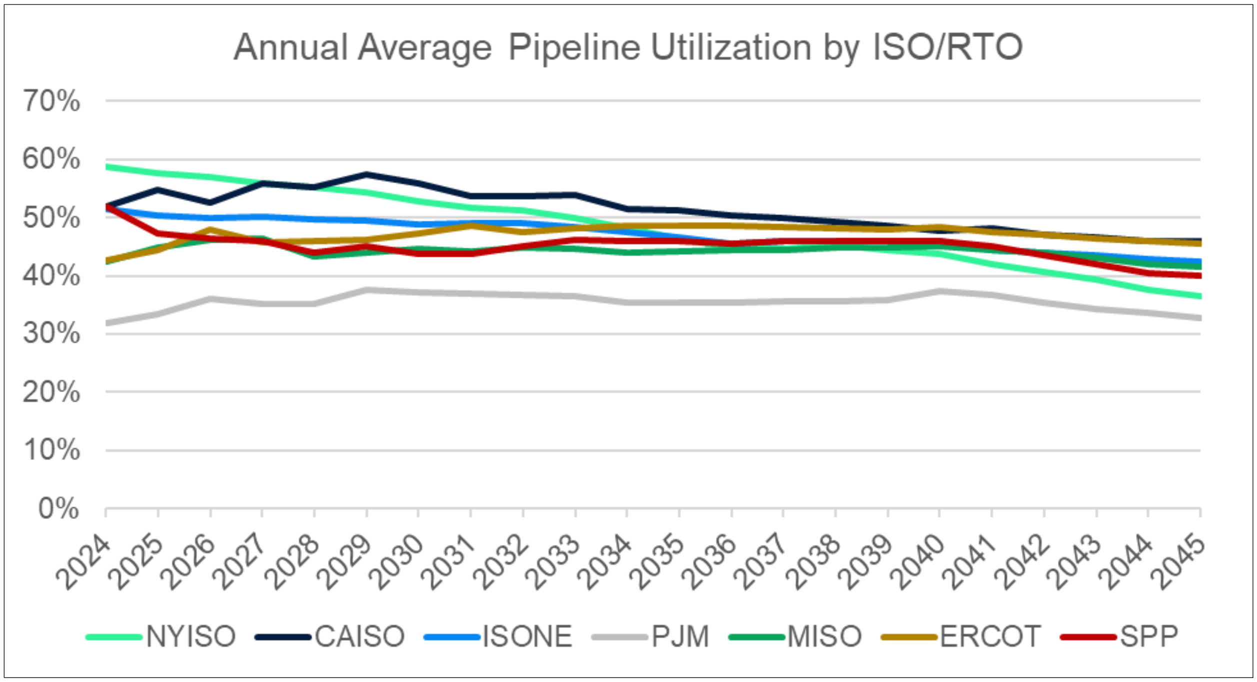
Source: U.S. Energy Information Administration and ICF Q3 2023

Between 2023 and 2029, there is an expected increase of 2,615,000 HP or 1,961 MW of additional interstate compression capacity throughout the country. That represents over a 10% increase in interstate natural gas pipeline compression capacity requirements between the estimated 2022 capacity of 21,339,000 HP and the projected 2029 compression capacity requirements of 23,954,000 HP. Most of that compression increase can be seen in the first four years of this forecast due to domestic and export demand growth and corresponding pipeline projects in that time horizon.

3.3 Compression Capacity Requirements Through 2045

To provide an estimate of long-term interstate natural gas pipeline compression capacity requirements, ICF utilized its GMM Q3 2023 pipeline capacity and flow data forecast. For each ISO/RTO region, annual average pipeline utilization values were calculated. This regional natural gas pipeline utilization outlook represents the long-term trends of compression requirements. As shown in Figure 2, each region has a slightly different projection, but the general trend is stagnant with no significant utilization increase or decrease after 2029 throughout each region. Annual average pipeline capacity utilization in MISO, ERCOT, and PJM will increase 2%, 5%, and 5% respectively between 2024 and their peak in 2030. Peak day and peak month utilization, and thus peak period compression requirements, will be much greater than the annual average due to continued heating demand and as ISOs/RTOs transition to renewable generation and rely on dispatchable generation, including gas-fired generation, to perform when renewable generation cannot. This could lead to higher hourly peak demands on the gas pipeline system, which will require additional compression so that the pipeline can meet these increased hourly loads. This forecasted utilization provides the basis for ICF's expectation that the interstate pipeline compression will still require maintenance, refurbishment, and replacement for the duration of the forecast horizon.

Figure 2 - Annual Average Pipeline Utilization by ISO/RTO

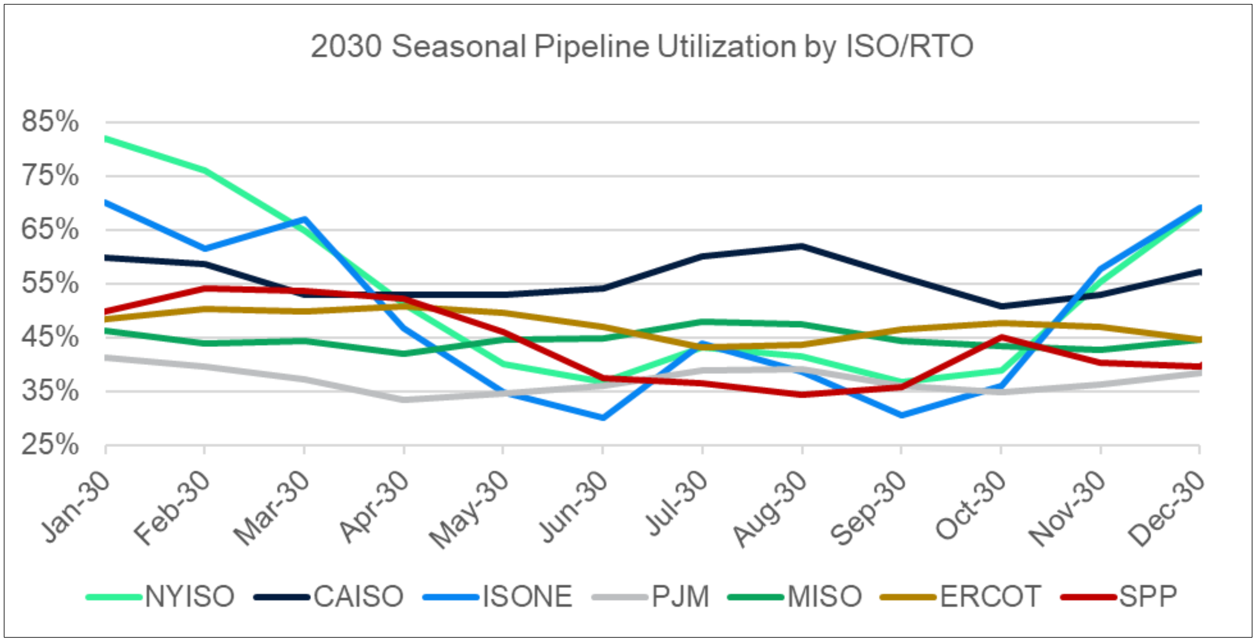


Source: ICF Q3 2023 Base Case Gas Market Forecast

3.3.1 Seasonal Compressor Station Requirements

ICF developed a seasonal compression load profile using a similar method as in Figure 2, with its GMM Q3 2023 natural gas pipeline flow and capacity data yielding pipeline utilization. Figure 3 displays a representative forecast year's – 2030 – seasonal pipeline utilization profile for all seven ISO/RTO regions. Each region shows both a winter and summer seasonal peak, representing the different natural gas demand requirements from heating and power generation (primarily for air conditioning) respectively. The pipeline and compression seasonal profiles in each region are expected to follow similar trends as the pipeline utilizations seen in the figure. Regions like NYISO and ISONE have large seasonal utilization fluctuations, while MISO and PJM have less pronounced seasonality. Peak day utilization in all these regions can reach 100% supported by the fact that interstate pipelines in many regions of the country are fully contracted and require capacity additions to meet incremental demand. Meeting additional winter demand in NYISO and ISONE and additional summer demand in ERCOT, for example, will require additional compression capacity in addition to what is forecasted in ICF's Q3 2023 base case shown in these figures.

Figure 3 - 2030 Seasonal Pipeline Utilization by ISO/RTO



Source: ICF Q3 2023 Base Case Gas Market Forecast

This study's analysis focused on the potential peak electricity demand for interstate natural gas pipeline compression. Below is a description of the methodology and the conclusions of that analysis.

3.4 Regional Compression Requirements

3.4.1 Overview of Dataset

ICF obtained compression data from the publicly available Homeland Infrastructure Foundation-Level Data[6] (HIFLD) platform. This database includes detailed geographic information and key characteristics for each compressor station, such as the HP capacity. These HP values were converted into megawatts (MW) using a standard conversion[7], which supported the electric load analysis performed throughout this study.

3.4.2 ISO/RTO Overview

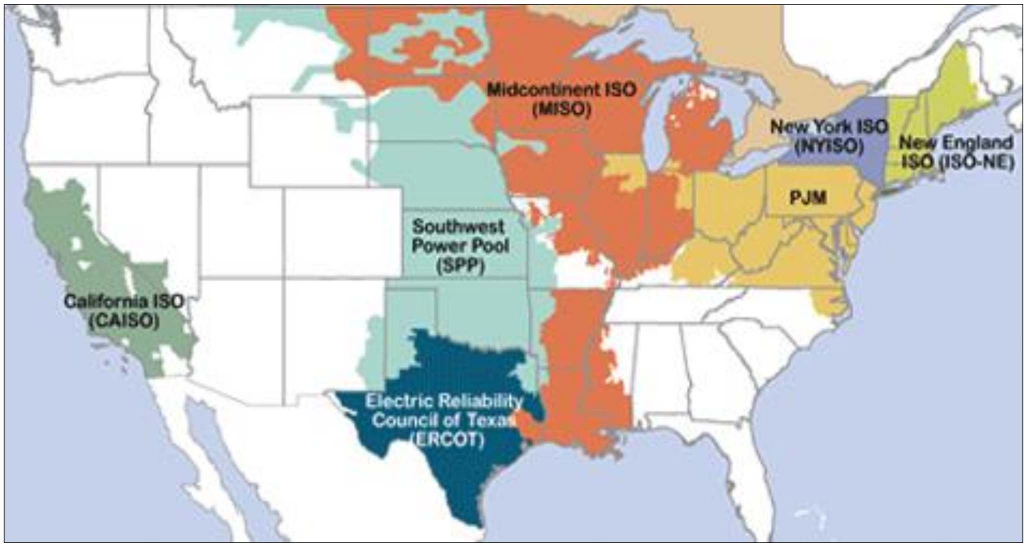
ICF geographically grouped compressor stations into regions consistent with the electric load ISO/RTO regions in the country. ISO/RTOs are organizations that coordinate, monitor, and control

[6] ICF used the 2022 HIFLD Compressor Database to estimate the current interstate natural gas compression capacity in HP. In some cases, ICF halved the capacity for compressor stations that appeared to be double counted (possibly because they are bidirectional) to obtain the most accurate estimate of compression capacity. Without these revisions, for example, the state of Washington would have been one of the largest states by compression capacity in the country, which does not reflect accurate compression infrastructure. https://hifld-geoplatform.opendata.arcgis.com/datasets/geoplatform::natural-gas-compressor-stations/explore?location=36.564378,-96.043033,5.79

[7] 1000 HP = 0.75 MW

the electric grid in a state or region. ICF focused on the seven different ISO/RTOs throughout the country, which can be seen in Figure 4. CAISO, ERCOT, ISONE, MISO, NYISO, PJM, and SPP are the ISO/RTOs. CAISO, ERCOT, and NYISO represent California, Texas, and New York respectively, while the other regions encompass multiple states. For example, PJM includes thirteen states on the East Coast.

Figure 4 - U.S. Electric Load Regions

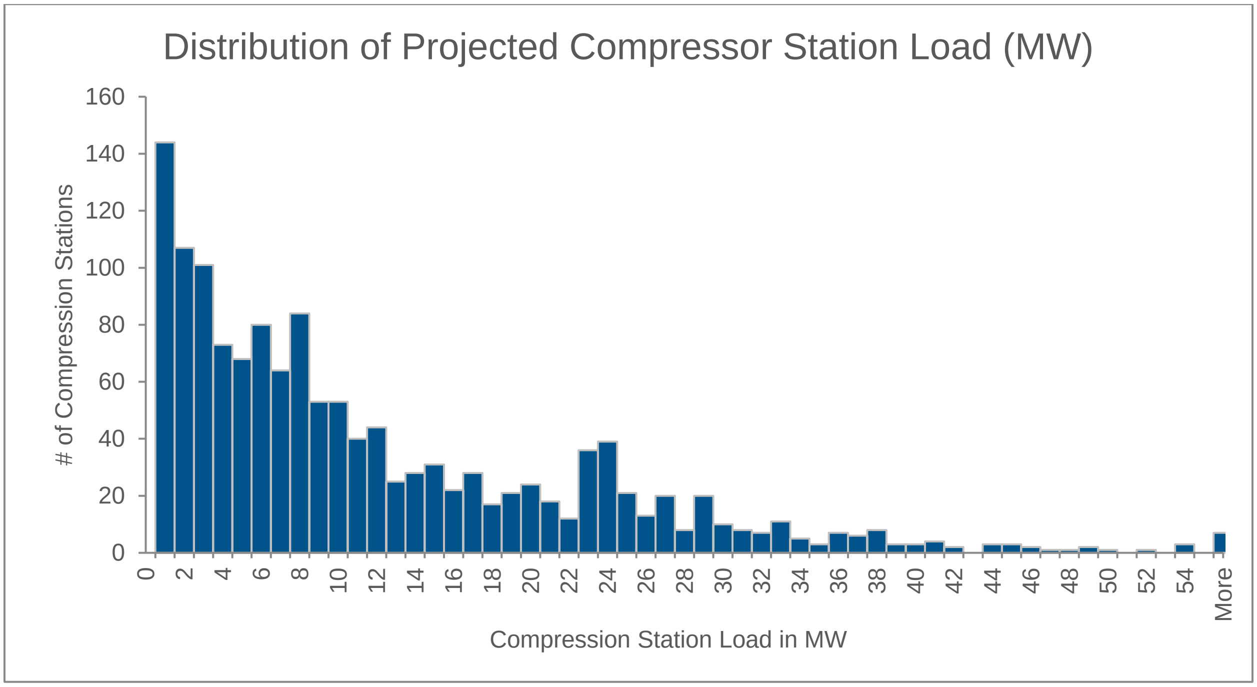


Source: FERC

3.4.3 Electric Compression and ISO/RTO Electric Demand

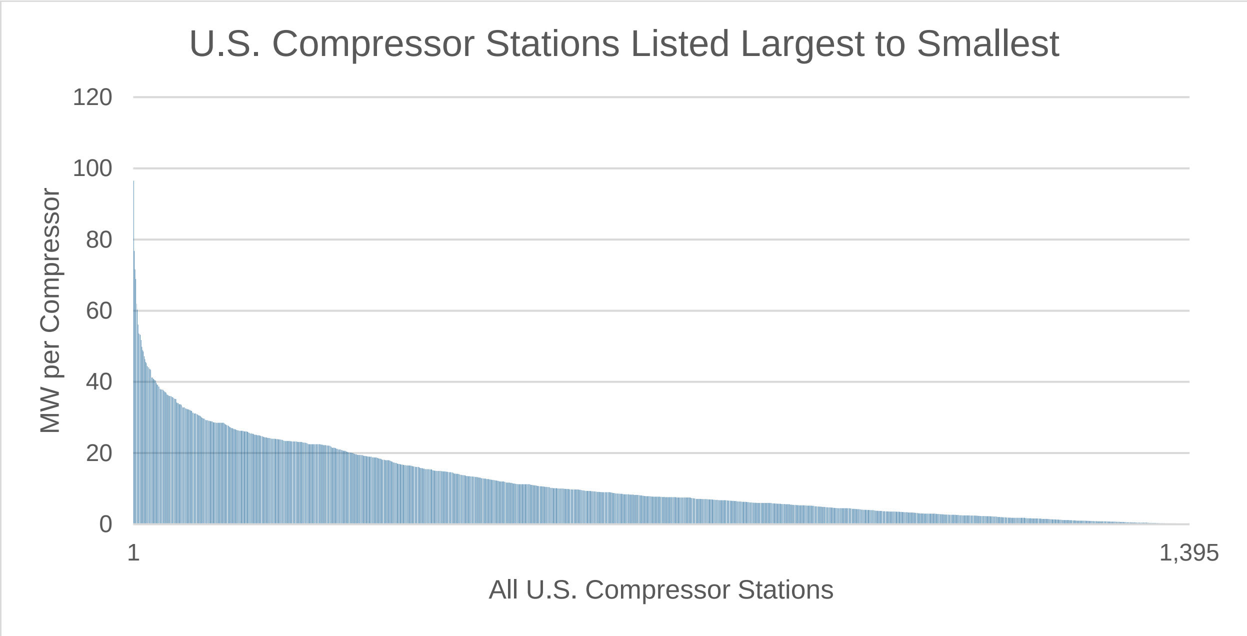
The estimated peak load for compressor stations throughout the country ranges from <1 MW to 97 MW. The average per-station estimated load is 11 MW, but this distribution is skewed as seen in Figure 5; more than 50% of compressor stations are rated under 8 MW and more than 80% of compressor stations are rated under 21 MW. Figure 6 shows all 1,395 compressor stations by their individual compression capacity values in MW, from largest to smallest. This graph is also skewed, showing how a large amount of the total compression capacity falls within just a small subset of the compressor stations across the country. In fact, the top 25% of compressor stations by MW capacity (18 MW – 97 MW) – roughly 350 stations – represent close to 60% of the total compression capacity between all 1,395 stations.

Figure 5 - Distribution of Projection Compressor station Load in Megawatts



Source: HIFLD Compressor Database

Figure 6 - Compressor Capacity by Number of Stations (MW), Listed Largest to Smallest

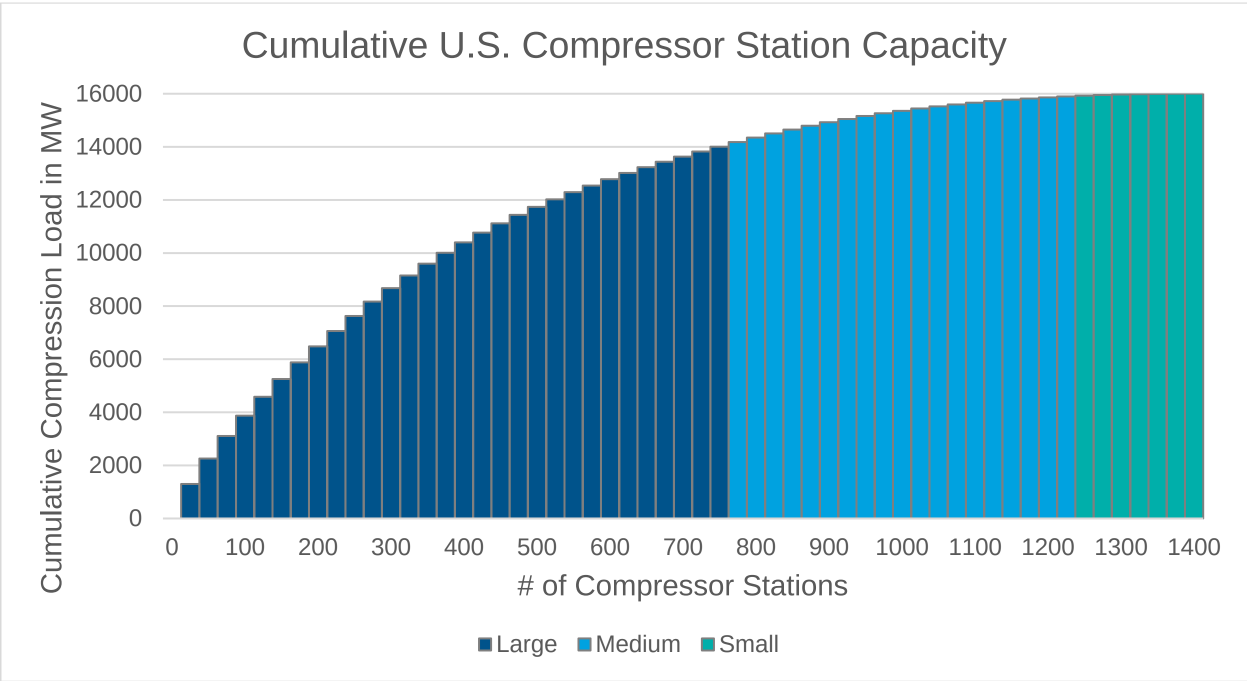


Source: HIFLD Compressor Database

Figure 7 shows the *cumulative* capacity of all compressor stations. Put into columns of 25 stations, the 1,395 compressor stations are listed from largest to smallest according to MW of capacity.

Again, nearly all the total compression – almost 14,000 MW as seen on the vertical axis, nearly 90% – falls within the compressor stations categorized as large (dark blue), while the medium and small sized compressor stations (light blue and green, respectively) account for the remaining 10% of total compression capacity.[8]

Figure 7 - Cumulative Compression Capacity by Number of Stations (MW), Listed Largest to Smallest

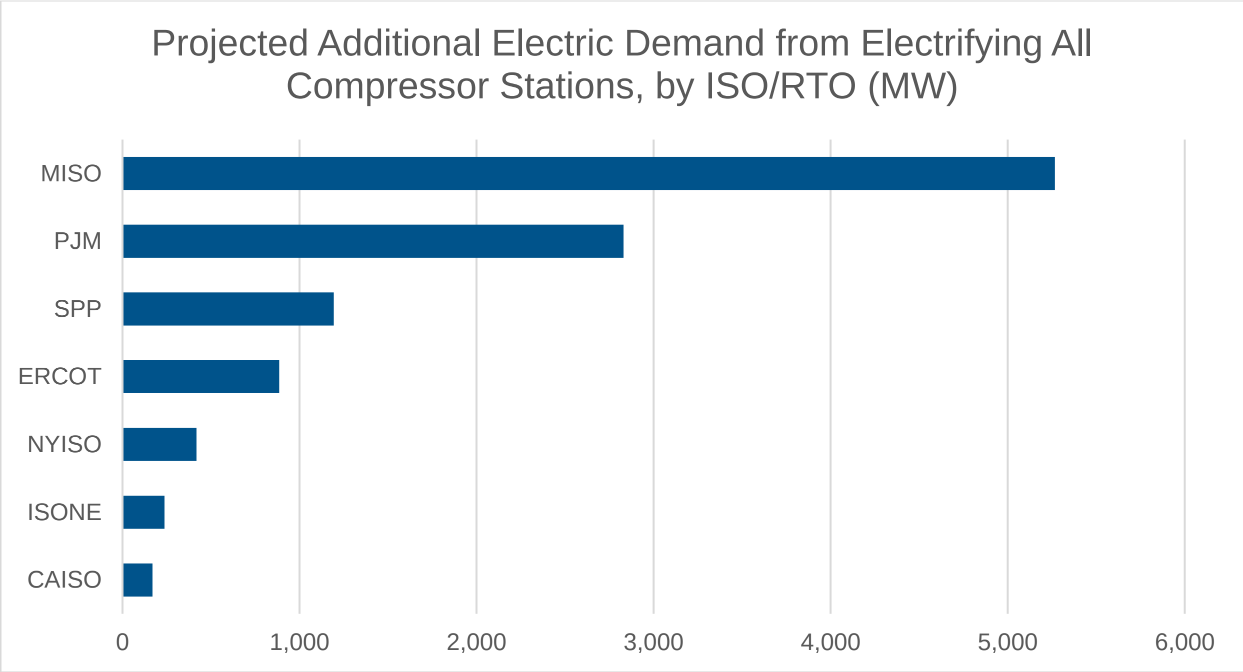


Source: HIFLD Compressor Database

Figure 8 shows the projected, additional electric load that would result from electrifying 100% of the natural gas compressor stations in each of the seven ISO/RTOs. As shown, 75% of potential U.S. electric compression load falls within the MISO and PJM regions, which equates to just over 8,000 MW of electric load.

[8] The categorization of compression stations as large, medium, and small is detailed in section 3.4.5 of this study.

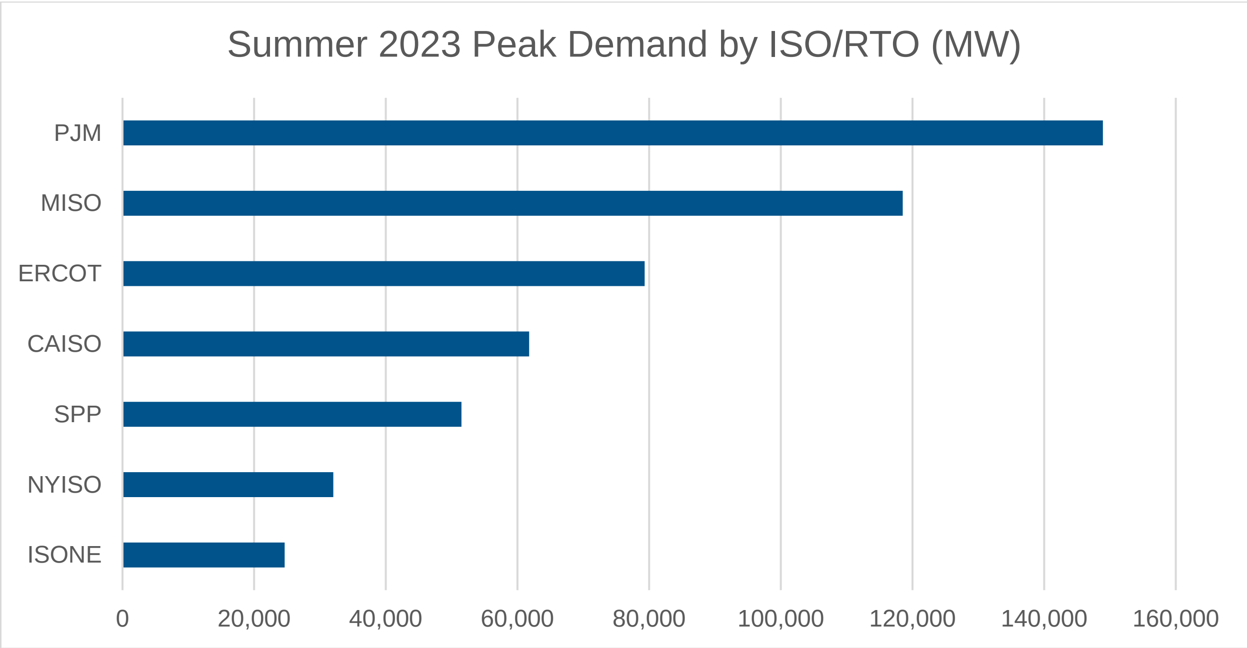
Figure 8 - Projected Additional Electric Demand from Electrifying All Compressor stations, by ISO/RTO, in Megawatts



Source: ICF and HIFLD Compressor Database

Figure 9 shows 2023 total projected peak electric demand for each of the seven ISO/RTO regions. PJM has the largest peak demand at around 150,000 MW, which is more than double the average peak demand of all seven regions. MISO has the second largest with around 120,000 MW, close to PJM. In fact, the total peak demand among the other five regions is still less than the total of PJM and MISO, highlighting the relative amount of demand in these two regions.

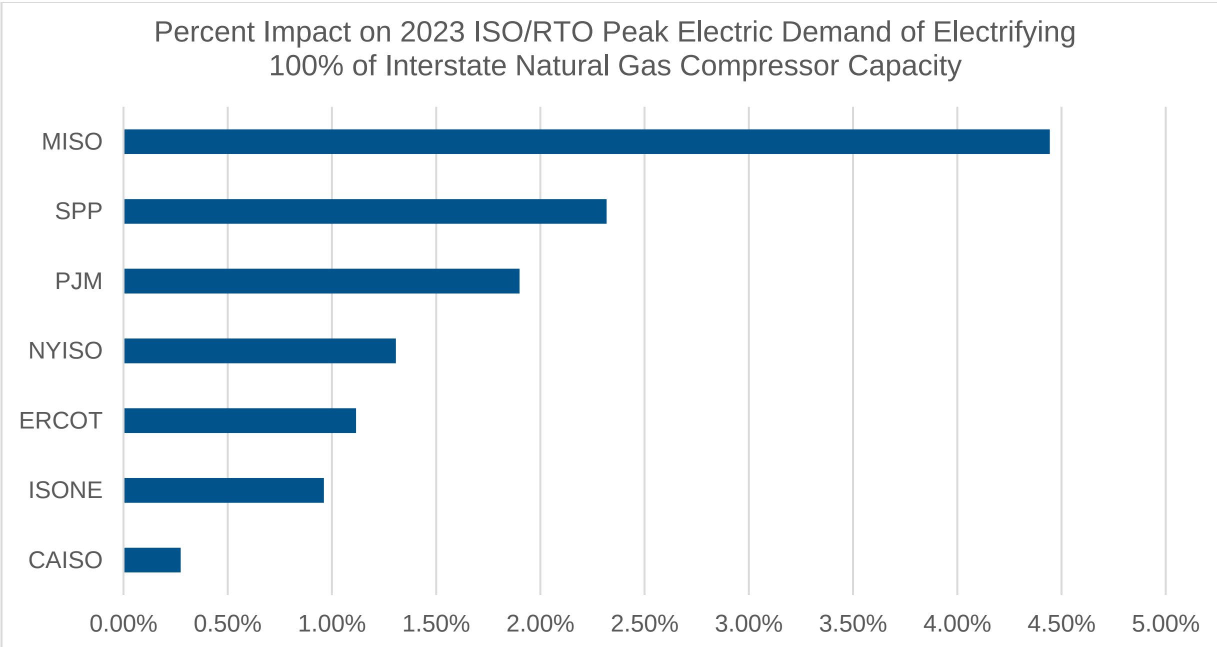
Figure 9 - Summer 2023 Peak Electric Demand by ISO/RTO in Megawatts



Source: ISO/RTO Load Forecast Reports: NERC 2021 ES&D, MISO 2021 Energy and Peak Demand Forecasting, ERCOT 2022 LTLF, CAISO 2020 CEDF Report, SPP 2020 Annual Report, NYISO 2020 Gold Book, ISONE 2022 CELT Report

Comparing the estimated potential electrified natural gas compression demand to the electric peak demand at the ISO/RTO level, Figure 10 shows estimated demand from electric gas compression represents less than 2.5% of projected 2023 peak electric demand in six out of the seven ISO/RTO regions. MISO is the only outlier, as electric compression makes up an estimated 4.5% of peak demand. This is because MISO, while having the second largest peak demand of the ISO/RTO regions, has more than triple the average of projected electric compression across the seven regions. In all these regions, but especially regions like PJM, MISO, and ERCOT which have large peak demand requirements today, the additional generation and transmission infrastructure required to meet the additional demand from electrified compression could require significant development time and investment.

Figure 10 - Percent Impact on 2023 ISO/RTO Peak Electric Demand of Electrifying 100% of Interstate Natural Gas Compressor Capacity



Source: ISO/RTO Load Forecast Reports and HIFLD Compressor Database

3.4.4 Electric Compression and ISO/RTO Demand Growth

The forecasted peak electric demand growth between 2023 and 2030 for each ISO/RTO is shown in Figure 11. MISO and ERCOT's peak electricity demand are expected to increase by about 8% each, while SPP is expected to increase by about 6%. The most notable growth is seen MISO, as it is expected to grow by close to 9,500 MW by 2030. MISO also has the largest peak demand out of these three regions. NYISO's peak demand is projected to decrease by 2030. While this decrease is only by about -1%, it is significant when considering the additional load required from projected electric gas compression would reverse that declining trend and lead to peak demand growth. The ISO/RTO load growth forecasts generally do not account for potential large, increased loads for electrification of stationary loads and transportation. Electrifying natural gas compression would accelerate that growth.

Figure 11 Projected Demand Growth to 2030 for ISO/RTOs in Megawatts

Source: ISO/RTO Load Forecast Reports

Figure 12 shows forecasted ISO/RTO peak demand growth between 2022 and 2030 (light blue), as well as the potential growth realized from electrifying all compressor stations (dark blue). In the MISO, PJM, and ISONE regions, the potential growth from electrifying compression is relatively large compared to the forecasted peak demand growth. For example, the forecasted peak demand growth between 2023 and 2030 in MISO is 9,500 MW, while the potential additional growth from compression electrification is over 5,200 MW. Thus, the forecasted peak demand growth between 2023 and 2030 in MISO would experience an additional 55% increase in demand growth if all compressor stations in the region were electrified. This can also be seen in the other two regions, PJM and ISONE, as the potential growth in MW from electrifying compressor stations is large relative to the ISO/RTO peak demand growth forecasts. In ERCOT, SPP, and CAISO, this trend is less pronounced, which can be seen by the bigger difference between the different colored bars.

For NYISO, the potential additional electricity demand from converting currently gas-fired compression to being electricity-powered is 418 MW, while the currently forecasted peak demand growth between 2023 and 2030 is -334 MW. NYISO is the only ISO/RTO region forecasted to have a decline in 2030 peak demand and that declining peak demand trend could be reversed by compressor electrification. In all the ISO/RTO regions, the potential additional electricity demand for natural gas pipeline compression could require additional power generation and transmission infrastructure.

Figure 12 - Forecasted ISO/RTO Peak Demand Growth to 2030 for ISO/RTOS and Potential Growth From Electrifying Compression (MW)

Source: ISO/RTO Load Forecast Reports and HIFLD Compressor Database

As stated above, the potential impacts on regional and state electricity demand in this study focus on the effects on peak electricity demand. Peak demand drives infrastructure planning so it is logical to analyze that for this study. But the effects of electrifying compression on sub-state and local demand, as well as the effects on seasonal and hourly load, will be critical for understanding the impact. For example, the local electric grid near electrified compressor stations will have a much higher percent of peak demand occupied by this additional electric compression. The degree to which additional compression load stresses the local system needs to be considered. If compression power demand aligns with heating end uses, the peak from both could combine to elevate the electric reliability needs.

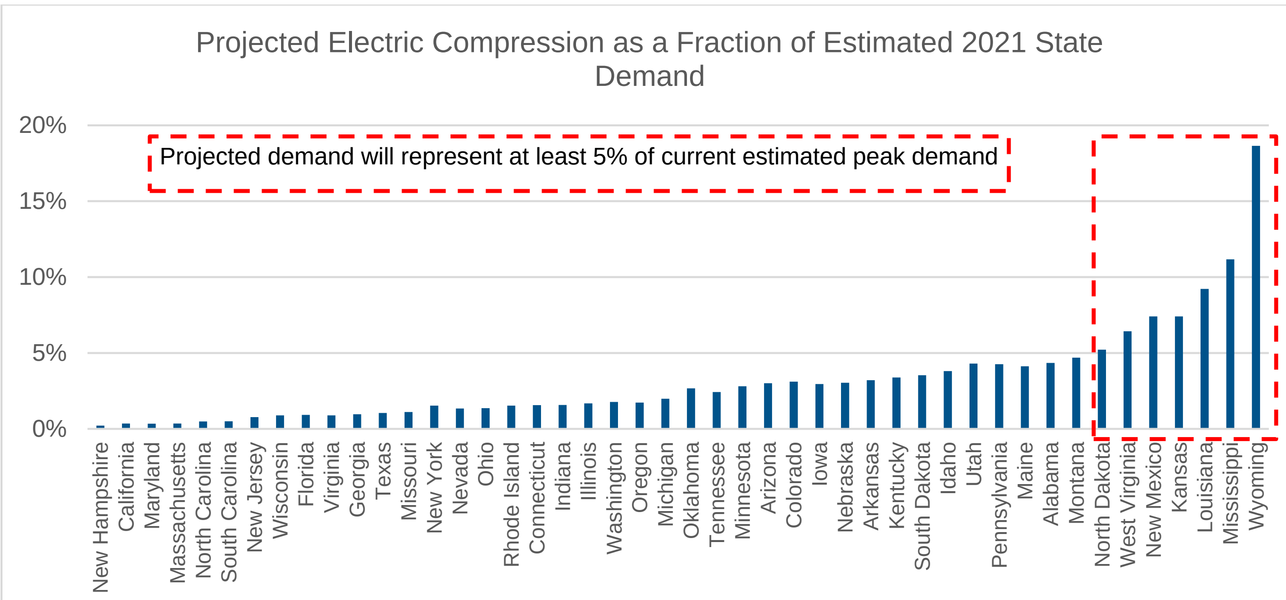
3.4.5 Gas Compression and State Level Peak Demand

Figure 13 and Figure 14 show projected electric gas compression load as a fraction of estimated 2021 state demand. ICF estimated the state level electricity demand in MW using state level EIA data on electric consumption.[9] ICF used this state level consumption data along with NERC data on load factors to estimate the peak demand at the state level.[10] In seven states, projected load from electric compression represents at least 5% of current estimated peak demand. Louisiana and West Virginia are included in these seven, which are two out of four of the states with the largest number of compressor stations. The other two states, Texas and Pennsylvania, have compression making up less than 5% of peak demand, which represents the relatively larger peak demands in these states.

[9] https://www.eia.gov/electricity/state/
[10] https://www.nerc.com/pa/RAPA/ESD/Documents/2021_ESD.xlsx

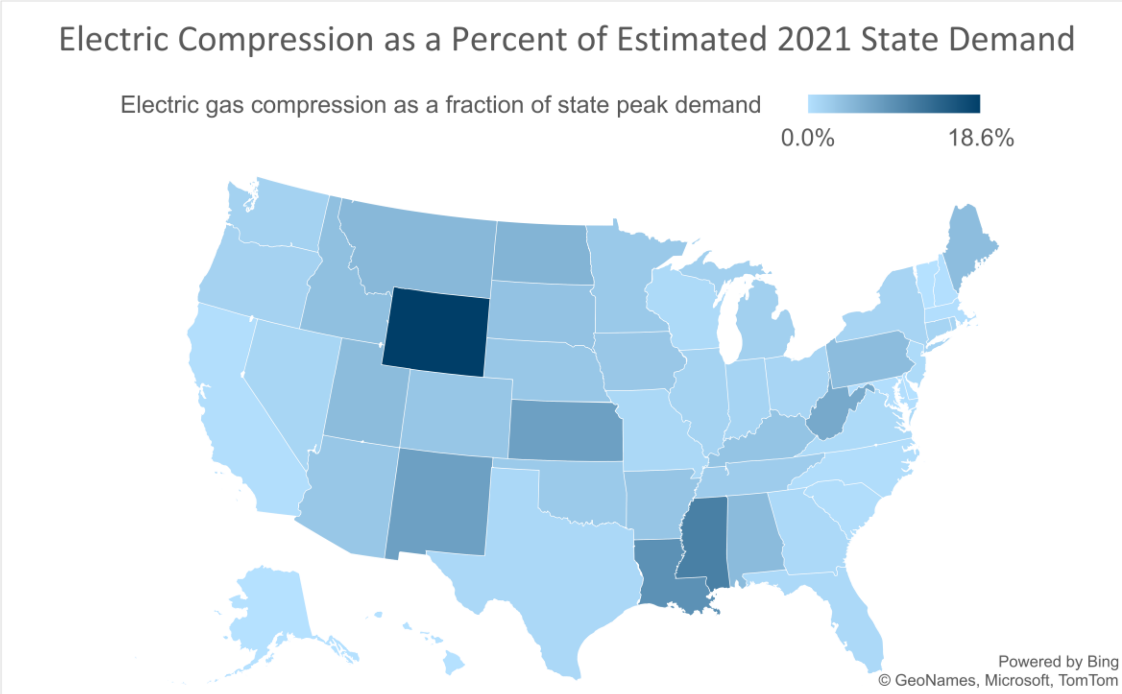
Within each state, some localities' additional electric load from compressor stations would comprise higher proportions than are shown in Figure 14. For example, while the entire state of North Dakota has electric compression making up around 5% of state electric demand (as shown by the red-dotted box), the electric grid near the compressor stations will have a much higher percent of peak demand occupied by this compression. Alternately, locations in the state that are not close to these compressor stations would have electric grid loads that are virtually unchanged from this added electric compression. The degree to which additional load stresses the local system needs to be considered.

Figure 13 - Projected Electric Compression as a Fraction of Estimated 2021 State Peak Demand



Source: ICF and EIA State Data

Figure 14 - Heat Map of Projected Electric Compression as a Fraction of Estimated 2021 State Demand



Source: ICF and EIA State Data

3.4.6 Key Considerations when Electrifying

Key considerations when electrifying gas compressor stations include the peak electric power the station will demand, the electric consumption profile (seasonal and daily), the proximity of the station to existing grid infrastructure, the type of grid infrastructure in the area, the spare capacity of that grid infrastructure, the reliability of electric supply, and its effect on gas system reliability.

The peak electric demand of a gas compressor station will determine the type of utility infrastructure required to serve the facility, with higher peak demands requiring more robust service installations. At higher peak demand levels, which will typically require high-tension[11] service voltages, a customer-owned substation will need to be constructed on the compressor station site. Also, the timeline for the utility to construct the service installation is more likely to be longer for higher peak demands.

180 of the smaller compressor stations or about 10% of the total will be serviceable with a low-voltage service.[12] If converted from natural gas to electricity, each of these facilities would have demand levels up to 1,275 kW, on par with a small shopping plaza that is fed by a pad mounted transformer behind or adjacent to the facility. The remaining 1,215 compressor stations will require high-tension service. About 456 of these facilities would have peak demands of between 1,275 kW and about 7,000 kW, similar to medium to large office buildings and will likely be able to receive service via a distribution line feeding a customer installed substation. The remaining

[11] High-tension service generally refers to service voltages above 600 volts.
[12] 600 volts or less.

759 compressor stations will not only require a high-tension service but because of their demand levels, 7,000 kW to 97,000 kW[13], similar to the demand of hospitals, colleges, universities, and medium to large industrial facilities, they may also require a utility-installed substation on-site to transform transmission level voltages down to typical high-tension service voltage which then would feed a customer installed substation.

In some cases, there will be a mismatch between the compressor station peak demand and the nearest available infrastructure such as when the station demand is suitable for low-voltage service and the nearest infrastructure is high-voltage transmission. In these types of circumstances, costs will be higher, and timelines will be longer as the utility will need to do more work to extend the appropriate infrastructure. It is also important to note that the nearest transmission line to a compression facility may not be owned by the local utility and may in fact be a transmission line that traverses the territory, requiring the pipeline operator to negotiate with the transmission owner rather than the local electric utility if they are not the same entity.

3.4.7 Reliability

The natural gas transmission system and the electrical grid are integrally linked together, and the reliability of the natural gas system is critical to the reliability of the electric grid. In the absence of gas-fired alternatives, power outages at natural gas compressor stations would lead to drops in natural gas deliverability throughout the system, potentially leading to natural gas deliverability challenges during peak demand periods. As was observed during 2021's Winter Storm Uri, outages at natural gas pipeline compressor stations can lead to the loss of natural gas supply at power generation facilities, which can create a dangerous feedback loop in which more electric powered compressors lose their electricity supply.[14]

This risk differs by region and by the specific circumstances at each compressor station. According to ICF's analysis, utilities in the least reliable quartile of the U.S. have reliability performance, as measured by the System Average Interruption Duration Index (SAIDI)[15], are six times more likely to experience a serious outage than the next quartile. These data imply that there are some regions and utilities that could provide much more unreliable electricity service than others, and that should be considered when converting natural gas compressor stations to electricity. Regions or utilities that have more unreliable electricity service may be a greater risk of not being able to provide constant service, which could lead to unplanned compressor outages and cascading natural gas system and electrical system outages.

3.5 Roadmap for Electrifying a Compressor Station

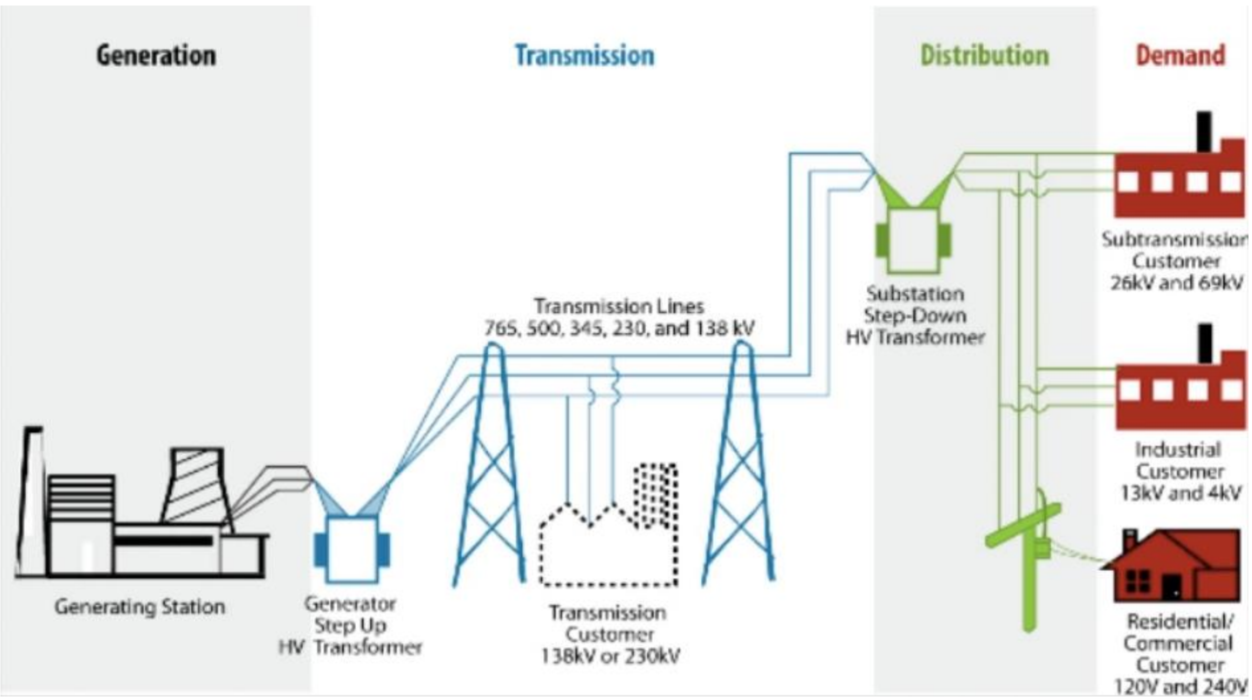
Natural gas compressors fill different roles on the gas transmission system depending on the size, location of the compression, as well as the size of the pipeline, and the location and volume of

[13] The largest compressor station in the U.S. is estimated to have a peak electric demand of 97,000 kW.
[14] The February 2021 Cold Weather Outages in Texas and the South Central United States: FERC, NERC and Regional Entity Staff Report. November 2021. Federal Energy Regulatory Commission, North American Electric Reliability Corporation, and Regional Entities. Page 116.
https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and
[15] System Average Interruption Duration Index (SAIDI) is a measure of the annual average number of minutes of interruption for customers served by a utility.

natural gas demand. Some of the compressors can easily be electrified with minimal impact on the reliability of the system. The 180 stations with the lowest peak demand and requiring low voltage power, for example, are likely to have smaller impacts on the electrical grid and have less impact on the reliability of the gas transmission system than the larger compressor stations. Within that group of stations, those stations closest to existing electric distribution infrastructure would be the lowest cost and fastest to electrify, although there may be lack of headroom on the local distribution systems such that significant incremental infrastructure would be required even for small compressor stations. Further, critical facilities which have access to only radial distribution system lines (i.e., ones which are isolated branches of the larger distribution system) would have require redundant services such as onsite backup power supply to maintain the gas system integrity.

As shown in Figure 15 distribution system lines typically carry electricity to smaller electricity users in the residential and commercial sectors. Local electric distribution companies also typically serve industrial customers at higher voltages. Some industrial customers may directly connect to the bulk or transmission systems, but this is less common and requires step down transformers be installed for those customers.

Figure 15 - U.S. Electricity Generation, Transmission, and Distribution System



Source: U.S. Department of Energy and the Congressional Research Service

The next group of compressor stations that could be electrified could be prioritized by level of increasing demand, proximity to electricity distribution infrastructure, and the headroom on and reliability of the local electric utility distribution grid. As shown in Figure 15, transmission lines typically carry electricity over long distances. While compressor stations may have proximity to longer-distance high voltage transmission lines which share similar right-of-way corridors, the high voltage transmission system is not designed to support end-users directly so accessing the transmission network would have additional challenges.

Engaging electric utilities and potentially regulators will be important. Given the projected growth in electricity demand, it would be prudent, particularly in states such as Louisiana, Mississippi, and Nebraska where the projected gas compression demand is significant relative to state demand, to engage regulators and electric utilities to inform them of the potential impact of electrification on electric demand so that they can include this incremental demand in their load forecasting and capital planning processes.

The local electric utility will determine whether the existing electric transmission or distribution system can supply the station without significant system upgrades and if upgrades are required, what those will cost. The local utility will also determine the type of service connection they can provide for supplying the compressor station.

For each compressor station, the specific site requirements will need to be identified in order to fully prioritize and plan a roadmap for electrification of compression. The pipeline operator or an engineering firm will need to determine the electrical load requirements for the facility. The type of service connection will need to be identified by the local electric utility and will determine the electric infrastructure requirements on the compression site. Service reliability is also locationally specific, and the local electric utility should be able to provide service reliability data, although, since high-level reliability statistics may hide commercial and industrial customer reliability, further analysis may be required to project the reliability specific service configurations.

Depending on projected reliability, operators may choose to use dual-drive technology which provides a back-up in the event of loss of electric supply or may decide to pay the additional cost for a more robust electric service from the utility such as a dual supply from two independent sources.

Table 2 - Cost and Timing Considerations

Cost and Timing Considerations	
Factor	Cost and Timing Considerations
Compressor station peak demand	Higher peak demands will require more robust and complex service connections at higher cost and longer timelines.
Proximity and type of grid infrastructure	Greater distances from electric grid infrastructure will require more involved extension of existing utility distribution or transmission and longer timelines with utilities normally absorbing these costs. The extent to which the compressor station peak demand and the nearest available infrastructure are "aligned" will influence cost and timeline with greater mismatches being more costly and taking more time to address.[16]
Spare grid capacity	Electric utility grids with insufficient spare capacity to support the additional compression load will require upgrades with costs likely to be borne by the electric utility ratepayers (including the pipeline) but with potential impact to timelines.
Grid reliability	Compressor stations in lower reliability grids may require more robust or redundant electric service connections at higher cost and longer timelines.

Today's existing pipeline and compression capacity will continue to comprise the majority of gas pipeline infrastructure in the U.S. for the next few decades. In some regions, compression capacity needs will grow.

Peak day and peak month utilization, and thus peak period compression requirements are projected to increase faster than the annual average. As a result, interstate natural gas pipeline compression, whether gas-fired or electric-powered will still require maintenance for the long term.

There are many regions and states in which the demand for electricity for compression would comprise a significant amount of their current peak electricity demand or a significant amount of the expected growth in electricity demand. Large, electrified compressor stations could add enough electricity demand to the local transmission or distribution systems to warrant new power infrastructure.

The infrastructure requirements may be further expanded to provide adequate reliability to support the natural gas system integrity. For example, backup power sources (such as microgrids and on-site battery storage may be needed) in the event of electric transmission and distribution grid outages.

[16] An example of a mismatch would be a very low demand compressor station, equivalent to a McDonalds with the only nearby infrastructure being a 500 kV transmission line.

Pipeline operators considering electrifying gas-fired compressors will need to study the following issues: the peak electric power the station will require, the electric consumption profile (seasonal, daily, and hourly), the proximity of the station to existing grid infrastructure, the type of grid infrastructure in the area, the spare capacity of that grid infrastructure and the reliability of the electric system.

The reliability and resiliency of the nearby electric distribution, transmission, and generation will be an important consideration.

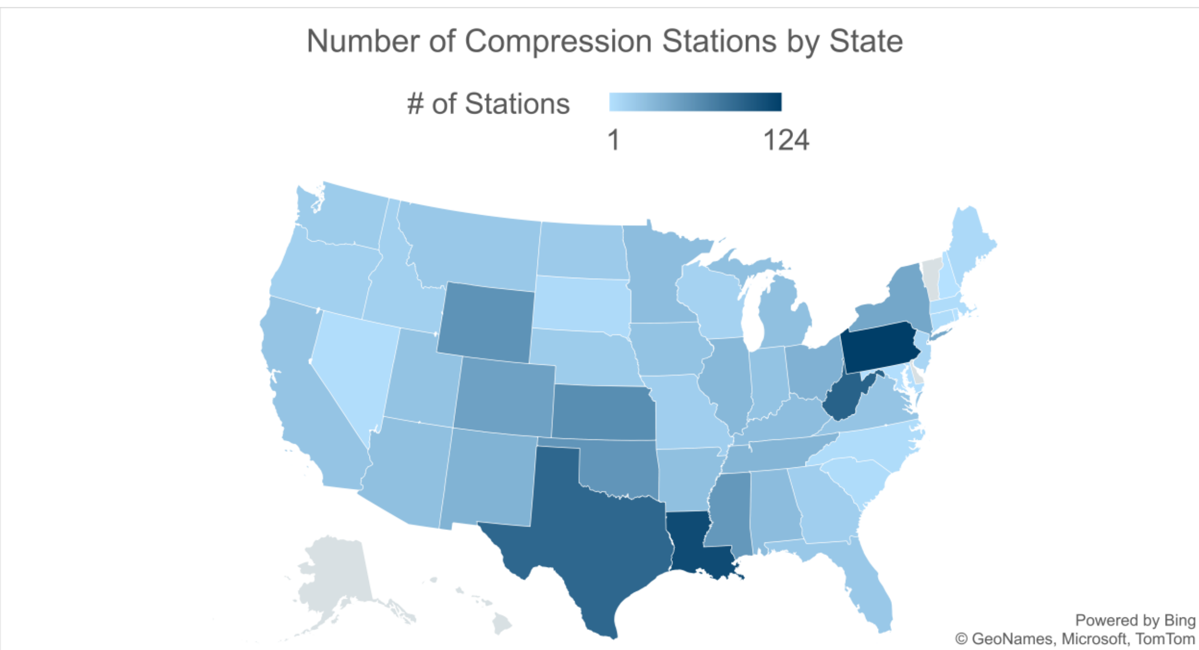
4 Determination of Key Focus Region

This section describes the scoring system used to select the ISO/RTO Region for the electrification of a single compressor station modelling. Note that some of the selection criteria used in this analysis are expected to be useful when considering a candidate transmission station asset for electrification by operators. For this study, the selected ISO/RTO Region will be referred to as the “Key Focus Region”. As part of this review, ICF researched several existing compressor stations, historical growth, and compression by state summarized below.

4.1 Compression Database Overview

As described in Section 3, ICF characterized the current state of the compression infrastructure on the U.S. interstate natural gas pipeline system by creating a database of the existing compressor stations as of 2022 using the publicly available dataset on the HIFLD website. The HIFLD contains key data on each compressor station, such as locational data, the horsepower (HP) capacity, and number of compressor units at the approximately 1,395 compressor stations on the interstate natural gas pipeline system across the country. Figure 16 is a map showing the number of compressor stations by state. Pennsylvania and Louisiana contain the most compressor stations as shown by the darker shading, each having around 120, while Texas and West Virginia also have a high concentration.

Figure 16 - Heat Map of Number of Compressor stations by State



Source: HIFLD Compressor Database and ICF

4.2 Compression Characteristics

Table 3 and Figure 17 summarize the natural gas compression in HP by state in the year 2022. The compression per state ranges from 6,000 HP in New Hampshire to over 2,000,000 HP in Louisiana, while the average per-state compression is about 450,000 HP. There is over

21,000,000 HP of total compression in the country which would convert to 16,000 MW of electric capacity.

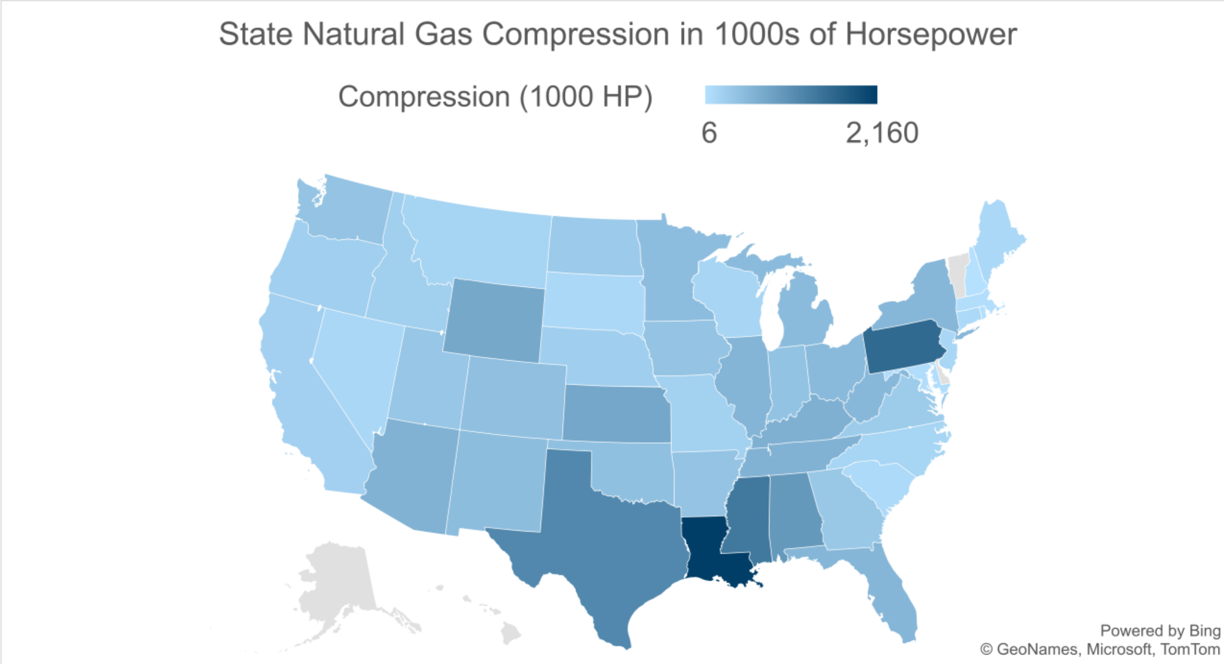
Table 3 - Natural Gas Compression in Horsepower in 2022 by State

Natural Gas Compression in Horsepower in 2022 by State			
State	Compression (HP 1000)	MW	Number of Compressor Stations
AL	959	719	29
AR	403	302	26
AZ	630	473	26
CA	226	170	23
CO	452	339	49
CT	112	84	5
FL	575	431	20
GA	342	256	15
IA	403	303	24
ID	248	186	14
IL	587	441	32
IN	406	304	24
KS	774	581	64
KY	651	488	28
LA	2,160	1,620	114
MA	46	34	5
MD	52	39	3
ME	123	92	7
MI	510	382	26
MN	482	361	28
MO	222	166	15
MS	1,383	1,037	56
MT	181	136	20
NC	170	127	5
ND	308	231	18
NE	253	190	17
NH	6	5	1
NJ	145	109	10
NM	485	364	36
NV	135	102	4
NY	558	418	45
OH	521	390	37
OK	445	333	58
OR	241	181	14
PA	1,574	1,180	124
RI	29	22	2
SC	102	76	5
SD	119	89	6

Natural Gas Compression in Horsepower in 2022 by State			
State	**Compression (HP 1000)**	**MW**	**Number of Compressor Stations**
TN	625	469	34
TX	1,180	885	93
UT	363	272	24
VA	286	215	23
WA	404	303	17
WI	159	119	12
WV	544	408	97
WY	759	569	60
Total	**21,339**	**16,004**	**1,395**

Source: HIFLD Compressor Database and ICF

Figure 17 - Heat Map of State Natural Gas Compression in 1000s of Horsepower



Source: HIFLD Compressor Database and ICF

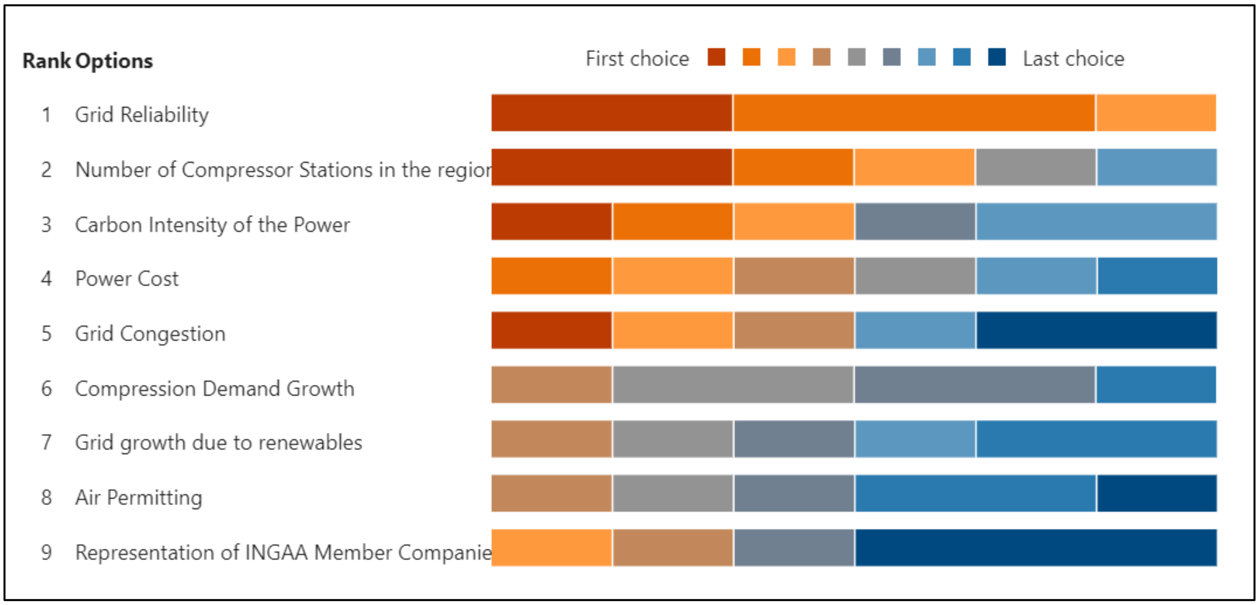
4.3 Criteria Selection and Weighting

ICF polled the INGAA Foundation's project steering committee members to rank a list of nine selection criteria pertaining to each ISO/RTO grid region in order to increase relevance of this study to regions represented by INGAA Foundation members and their respective company assets in the selection of the Key Focus Region.

In addition to regional ISO considerations, INGAA Foundation project steering committee members were polled about the importance of project development cost considerations. Included in this poll were regional asset variables such as compressor station quantity and compression demand growth, air permitting regulations, price of power, and carbon intensity of electric power. Other more grid specific considerations such as grid congestion, grid growth due to renewables, and grid reliability were also included in the poll. The poll was designed with the intent to consider a wide array of factors representing electrification considerations for pipeline companies. A composite of the poll results was then used to assemble a weighting for each of the nine criteria, with the higher weighted criteria being seen as more critical by the project team members polled.

The highest weight was assigned to grid reliability to correlate the poll with the initial purpose of the project. Grid reliability has been a central consideration for electrification for operators and stakeholders. This was followed by the number of compressors stations in the selected region. ICF believes this criterion was important to introduce statistical significance and increase the variety of compressors available for down-selection. The distribution of the INGAA Foundation project steering committee members survey results is presented in Figure 18.

Figure 18 - INGAA Foundation Project Steering Committee Member Compressor Selection Survey Results



Source: ICF

Upon review of the poll results, ICF developed a scoring matrix to evaluate the various ISO's relevant for this study further discussed in Section 4.4.

4.4 Key Focus Region Selection

With the selection criteria identified and weighted, ICF scored each ISO/RTO Region by the chosen criteria to determine the Key Focus Region. The results of the analysis are summarized in Table 4.

Table 4 - ISO/RTO Region Selection Criteria Scores

ISO/RTO Region Selection Criteria Scores								
Selection Criteria	**Weight (%)**	**CAISO**	**ERCOT**	**ISO-NE**	**MISO**	**NY-ISO**	**PJM**	**SPP**
Grid Reliability	25.0%	1	6	5	4	3	2	7
Number of Compressor Stations in the Region	20.0%	6	4	7	1	5	2	3
Carbon Intensity of the Power	15.0%	2	6	3	5	1	4	7
Power Cost	12.5%	7	1	5	2	2	3	1
Grid Congestion	10.0%	7	6	1	3	5	2	4
Compression Demand Growth	7.5%	7	1	7	4	7	3	2
Grid Growth Due to Renewables	5.0%	1	2	6	5	4	3	7
Representation of INGAA Member Companies within Focus Region	2.5%	0	0	0	0	0	0	0
Air Permitting	2.5%	7	1	3	1	3	3	1
	Score	4.08	4.13	4.73	3.08	3.45	**2.53**	4.45

The scoring scale indicated above ranks the ISO/RTO Regions, from first to seventh for each selection criteria, with regions tied in several cases, where scoring between regions could not be differentiated. Note that the representation of INGAA member companies within the focus region was not ultimately included in the final scoring. The lowest score indicates the region with the best potential for electrification. The weighting in each selection criteria was adjusted to reflect the results of the INGAA Foundation survey, discussed above.

The PJM regional transmission organization was selected as the Key Focus Region for this study, from the scoring.

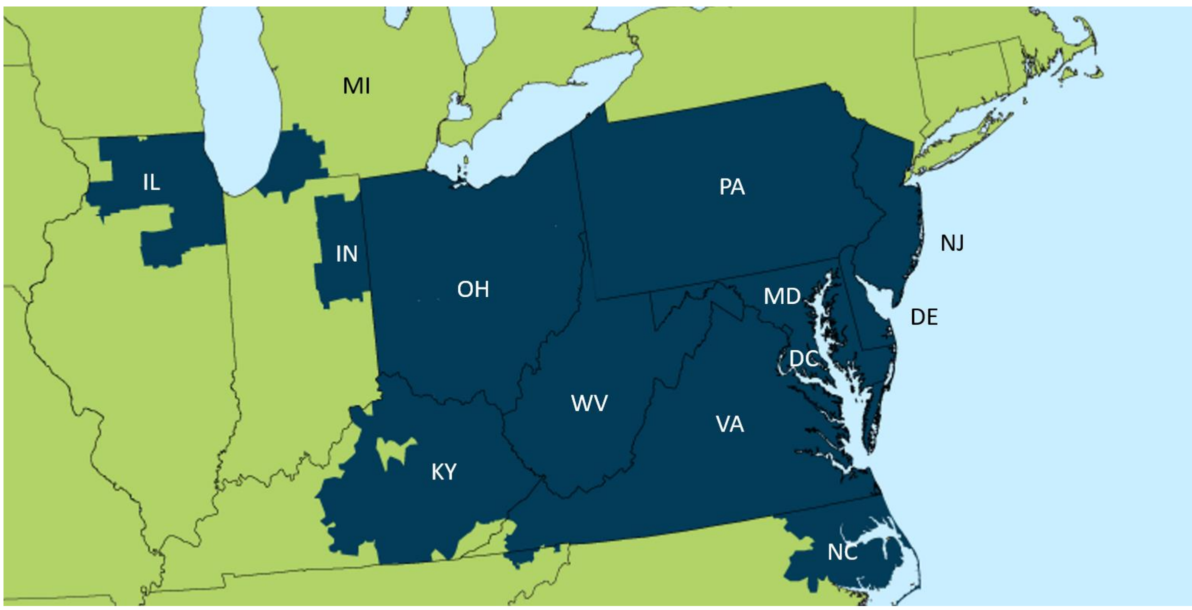
5 Candidate Compressor Station

This section describes the compressor station down-selection criteria and the data/design considerations for the selected replacement station within the Key Focus Region.

5.1 Compressor Station Selection

Based on the scoring metrics discussed in Section 4.4, PJM was selected as the RTO and Key Focus Region to be used as a basis for this study. ICF evaluated this key focus region to determine the number of compressor stations in each state and further evaluated it for additional considerations to determine a list of potential candidate stations which was filtered to a single candidate compressor station. The PJM region was evaluated for the various states contained within it identified in Figure 19.

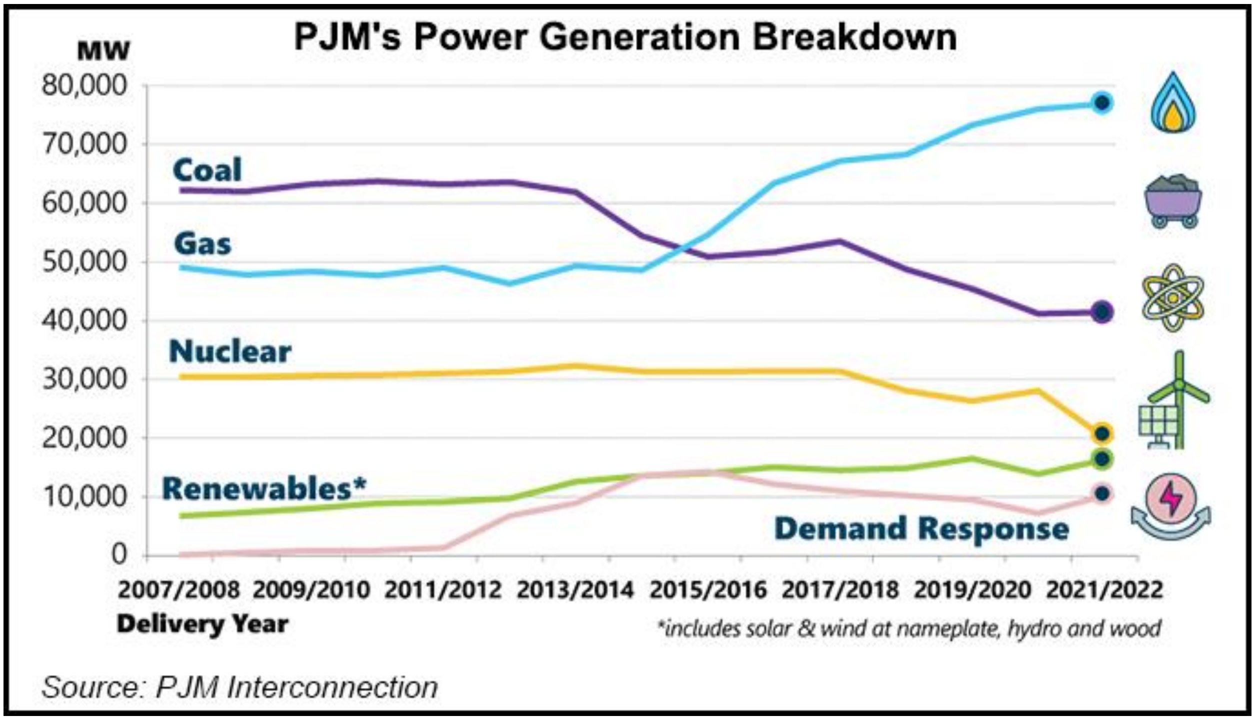
Figure 19 - Map of PJM



Source: ICF

To further determine a single state to focus on, the carbon intensity of each state grid was researched to align power generation with electrification and to avoid powering electric motor-driven compressors with higher carbon intensive sources than natural gas. Additionally, the growth of power generation balance from renewable sources over the next 10 years was evaluated to represent a transition energy mix. The team then further analyzed the various sources of power within PJM as indicated in Figure 20.

Figure 20 - PJM Power Generation Breakdown



The PJM grid was further evaluated at a state level for number compressor stations and grid power carbon intensity (Table 5).

Table 5 - Number of Compressor Stations and Grid Carbon Intensity by PJM State

Number of Compressor Stations and Grid Carbon Intensity by PJM State		
State	**# of Compressor Stations**	**Grid Power Carbon Intensity (lb O2e/MWh)**
PA	120	730
NJ	10	480
WV	97	1960
OH	37	1215
KY	28	1740
VA	23	600
IN	24	1640
MI	26	1010
IL	32	660

Source: HIFLD Compressor Database and ICF

Based on the data summarized in Table 5, ICF selected Pennsylvania as the study state, due to its large number of compressor stations and relatively low grid power carbon intensity score.

ICF performed a desktop analysis to evaluate the selection of a candidate compressor station within Pennsylvania. ICF searched the HIFLD database to select a compressor station that had multiple compressors (>3), with more than 10,000 certified compression horsepower (total horsepower at station), no existing electric compressors and no current active electrification projects. In many cases compressors are in remote areas and their reliance on natural gas is based on grid access in addition to economic considerations. To avoid outliers and unpredictable development timelines, the candidate compressor station search criteria was further filtered as described below.

ICF selected the candidate compressor station by reviewing the proximity of the various compressor stations to electric power transmission lines as proximity to transmission lines would theoretically reduce the development related expenses and development time required to expand the grid to allow for electrification of the candidate compressor sites.

With electric transmission proximity considered, the search for a candidate compressor station was narrowed across the state to include three proposed candidate sites. One of the three sites was eliminated as there was a major gas turbine driven compressor expansion planned at the compressor station; a second site was eliminated as there was also a significant expansion already planned at the compressor station, including addition of an EMD compressor. Hence, of the three short listed sites, a single candidate site was identified to use as a basis for this study. This single candidate compressor station was analyzed for assets described in Section 5.2.

5.2 Compressor Station Data

The candidate compressor station selected for this study has 13 existing natural gas driven reciprocating compressors located on site, several of which are potential candidates for replacement. ICF looked at replacement of older compressor assets as these compressors may not contain the latest emissions mitigation technology and were assumed to be due for end-of-life replacement relatively soon thereby avoiding the costs of adding emissions control at existing compressor assets. The existing conditions at the candidate compressor station is summarized in the Table 6 below.

Table 6 - Selected Candidate Compressor Station Specifications

Selected Candidate Compressor Station Specifications Data	Units	Value
Number of Compressor	-	13
Combined Certified Horsepower	HP	33,000
Compressor Types	-	Engine driven / 2-stroke recip.
Combined Rated Peak Capacity	MMSCFD	2,250
Suction Pressure	psig	580
Discharge Pressure	psig	765
Average (weighted) compressor (isentropic) efficiency	%	82.5
Average operating hours (assumed)	hrs/yr	6,000
Average % full load HP	%	75
Average engine heat rate	BTU/HP-hr	7,500
Average ambient temperature	^oF	60
Elevation above sea level	ft	400
CH4 Emissions	-	Per EPA 2023 GHGI, Annex 3

Source: Confidential

6 Compressor Replacement Assessment

This study evaluates the replacement of older natural gas engine driven/2-stroke reciprocating gas compressors with either one EMD driven centrifugal compressor, gas turbine (GT) driven centrifugal compressor, or a dual (EMD/GT) driven centrifugal compressor at the candidate compressor station identified in Section 5.

The dual drive option was included in the assessment to address issues with natural gas grid resiliency, during power outages and blackouts.

Information on each compressor replacement case is summarized in the sub-sections below.

6.1 EMD Compressor

The table below summarizes the scope for the replacement of three older engine driven, reciprocating compressors with a single EMD centrifugal compressor at the candidate compressor station.

Table 7 - Replacement EMD Centrifugal Compressor Specifications

Replacement EMD Centrifugal Compressor Specifications		
Data	Units	Value
Compressor Type	-	Multi-stage Centrifugal (API-617)
Drive Type	-	EMD/VFD
Rated Peak Capacity	MMSCFD	590
Suction Pressure	psig	580
Discharge Pressure	psig	765
Drive Rated Horsepower	HP	11,000
Compressor Seals	-	Dry gas
Average operating hours (assumed)	hrs/yr	6,000
Normal (average) operating power	kW	6,250
CH_4 Emissions	-	Per EPA 2023 GHGI, Annex 3

Source: Confidential

The compressor replacement scope includes the following:

- New compressor and drive package, with ancillary equipment.
- New compressor building
- New power control building
- Electrical interconnect & substation
- Transformer(s)

- New 24” gas piping, piping tie-ins, gas cooler and associated valving and instrumentation.

The grid interconnection was estimated to be approximately 5,000 ft from the compressor station and the grid interconnection costs was estimated to be $750,000 for the network expansion ($150/ft) plus $2MM for the high voltage substation addition (Total $2.75MM).

The estimated development cost was estimated to be $27.8 MM, which includes owner’s costs, interconnection (allowance), substation but excludes financing costs. Annual operating costs, excluding power costs, are estimated to be $0.42 MM/yr.

6.2 GT Driven Compressor

The table below summarizes the scope for the replacement of three (3) older engine driven, reciprocating compressors with a single GT driven centrifugal compressor.

Table 8 - Replacement GT Driver Centrifugal Compressor Specifications

Replacement GT Driver Centrifugal Compressor Specifications		
Data	Units	Value
Compressor Type	-	Multi-stage Centrifugal (API-617)
Drive Type	-	Gas Turbine
Rated Peak Capacity	MMSCFD	590
Suction Pressure	psig	580
Discharge Pressure	psig	765
Drive Rated Horsepower (at ISO Conditions)	HP	11,100
Compressor Seals	-	Dry gas
Average operating hours (assumed)	hrs/yr	6,000
Normal drive horsepower	HP	8,060
Normal (average) operating heat rate	BTU/hp-hr	8,400
Emission Controls	-	Dry low NOx
CH4 Emissions	-	Per EPA 2023 GHGI, Annex 3

Source: Confidential

The compressor replacement scope includes the following:

- New compressor and drive package, with ancillary equipment.
- New compressor building
- New auxiliary building
- New 24” gas piping, piping tie-ins, gas cooler and associated valving and instrumentation.
- New off-skid fuel gas piping, associated valving and instrumentation.

The estimated development cost, including the owner's costs, excluding financing costs is $24.7 MM. Annual operating costs, excluding fuel costs, are estimated to be $0.77 MM/yr.

6.3 Dual (EMD/GT) Driven Compressor

The table below summarizes the scope for the replacement of three (3) older engine driven, reciprocating compressors with a single dual drive centrifugal compressor.

Table 9 - Replacement Dual Drive Centrifugal Compressor Specifications

Replacement Dual Drive Centrifugal Compressor Specifications		
Data	Units	Value
Compressor Type	-	Multi-stage Centrifugal (API-617)
Drive Type	-	Dual (GT/EMD)
Rated Peak Capacity	MMSCFD	590
Suction Pressure	psig	580
Discharge Pressure	psig	765
GT Rated Horsepower (at ISO Conditions)	HP	11,100
EMD Rated Power	HP	11,000
Compressor Seals	-	Dry gas
Average operating hours (assumed)	hrs/yr	6,000
Normal (average) EMD operating power	kW	6,250
Normal (average) operating heat rate	BTU/hp-hr	8,400
Emission Controls (GT)	-	Dry low NOx
Permitted maximum GT operating hours/yr	hrs/yr	1,000
CH4 Emissions	-	Per EPA 2023 GHGI, Annex 3

Source: Confidential

The compressor replacement scope includes the following:

- New compressor and drive package, with ancillary equipment.
- New compressor building
- New auxiliary building
- New power control building
- Electrical interconnect & substation
- Transformer(s)

- New 24” gas piping, piping tie-ins, gas cooler and associated valving and instrumentation.
- New off-skid fuel gas piping, associated valving and instrumentation.

The estimated development cost, including the owner’s costs, interconnection (allowance), substation excluding financing costs is $34.6 MM. Annual operating costs, excluding fuel costs, are estimated to be $0.45 MM/yr.

7 Carbon Intensity Scoring and Methane Emissions

ICF conducted a carbon intensity and methane emissions analysis to determine the impact of the proposed electrification of the candidate site and its carbon impact.

7.1 Carbon Intensity Scoring

ICF calculated the amount of CO2 emitted at the candidate site for each of the compressor replacement cases. Carbon intensity is a typical measure used by companies as a key performance indicator (KPI), to track progress on reducing their carbon footprint. Additionally, carbon intensity is an important KPI as natural gas pipeline companies consider regulation, including the Inflation Reduction Act (IRA) 45V and 45Z credits.

7.1.1 Lifecycle Analysis Modeling

ICF conducted a life cycle assessment (LCA) to calculate pipeline transmission emissions and compare the carbon intensity of installing a new electric motor drive, gas turbine drive, and dual electric gas turbine drive compressor. ICF modeled overall pipeline transmission emissions over 1,900 miles to reflect the distance from Texas to New York. ICF also modeled and compared the emissions of one electric motor-driven compressor (EMD Compressor), one gas turbine driven compressor (GT Driven Compressor), and one dual driven compressor (GT/EMD Dual Driven Compressor). Additionally, ICF modeled the EMD Compressor and GT/EMD Dual Driven Compressor using the grid mix for five different states (Pennsylvania, Indiana, Illinois, Michigan, and Virginia) to show a range of carbon intensity scores based on grid mix. ICF used the latest version of the GREET model, released by Argonne National Laboratory (ANL) in March 2023, to conduct the LCA. The GREET1 model is an analytical tool that simulates the fuel lifecycle, also known as “well to wheels” energy use and emissions output of fuel systems. The GREET model is widely recognized as a reliable tool for life-cycle analysis of transportation fuels and has been used by several regulatory agencies (e.g., USEPA for Renewable Fuel Standard (RFS) and California Air Resources Board (CARB) for Low Carbon Fuel Standard (LCFS)) for evaluation of various fuels.

7.1.2 Data Collection

The following assumptions were used to provide inputs for this analysis. Energy and material inputs for this analysis are summarized in the tables below.

Table 10 – Inputs for LCA by Compressor Type

Inputs for LCA by Compressor Type			
Item	**Unit**	**GT Driven Compressor**	**EMD Compressor**
Normal drive power	HP	8,060	-
Normal drive heat rate	BTU/hp-hr	8,400	-
Normal electrical power	kW	-	6,250
Normal gas capacity	MMSCFD	293	293
Operating	hrs/yr	6,000	6,000

Table 11 - Natural Gas Transmission Inputs for LCA

Natural Gas Transmission Inputs for LCA			
Natural gas density	g/ft^3	20.8	California's GREET model "Fuel Specs" tab, cell E60 for natural gas at 60°F, 1 atm pressure
Natural gas transmission capacity	ton/hr	279.9	Calculated based on Normal Capacity of compressors
Natural gas transmission Energy Intensity	Btu/ton-mile	1,640	ANL GREET, "T&D" tab, cell B88
Natural gas transmission distance	miles	1,900	Google map from Texas to New York
Natural gas transmission overall energy demand	MMBtu/hr	872.6	Calculated
Natural gas	%	98	ANL GREET, "T&D" tab, cell CG114
Electricity	%	2	ANL GREET, "T&D", cell CG123

Source: ICF

Emission factors were pulled from ANL GREET. The electricity grid mix for the EMD compressor is based on the Reliability First Corporation (RFC) grid which is used in Pennsylvania at the location of this candidate compressor station. The emissions factors used in this analysis are summarized in the table below.

Table 12 - Emissions Factors from ANL GREET

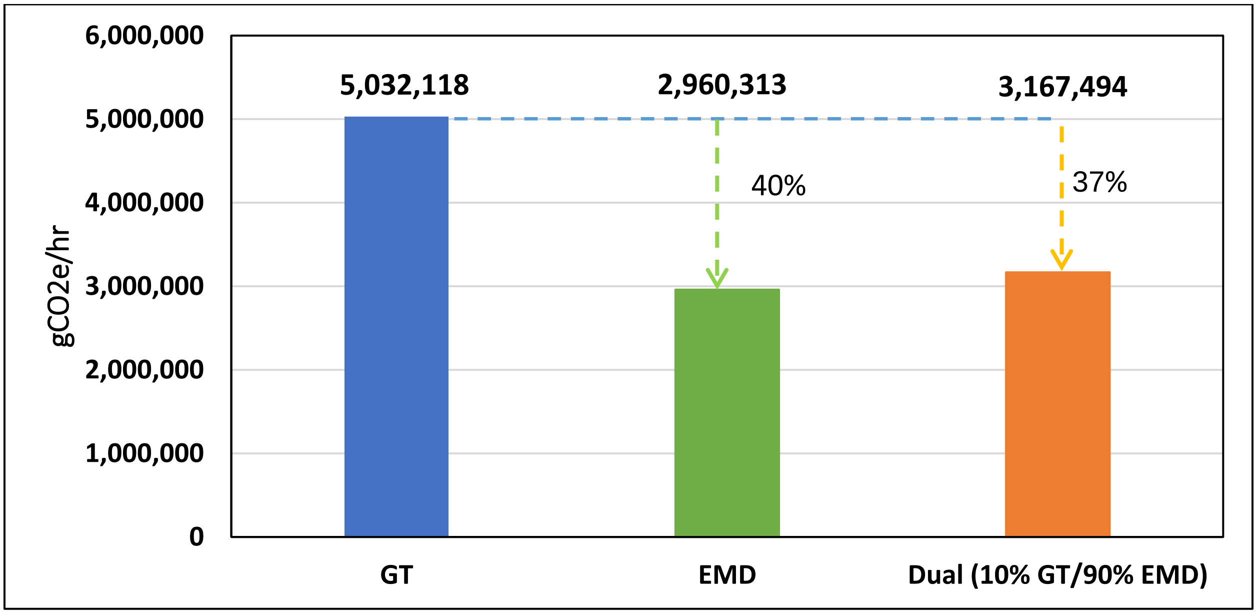
Emissions Factors from ANL GREET		
Item	**Units**	**Value**
Natural Gas for GT driven compressor	gCO2e/MMBTU	74,325
Electricity for EMD compressor	gCO2e/kWh	473
Natural gas in pipeline reciprocating engine	gCO2e/MMBTU	100,327
Electricity for pipeline reciprocating engine	gCO2e/kWh	466.5
Electricity in Pennsylvania	gCO2e/kWh	430.79
Electricity in Indiana	gCO2e/kWh	929.47
Electricity in Illinois	gCO2e/kWh	423.37
Electricity in Michigan	gCO2e/kWh	582.8
Electricity in Virginia	gCO2e/kWh	390.72

Source: ANL Greet

7.1.3 Carbon Intensity Scoring Results

The carbon intensity scoring results were calculated for overall natural gas transmission from Texas to New York. The carbon intensity scoring results also show a comparison of greenhouse gas (GHG) emissions for one compressor that is gas turbine drive, motor-driven, or dual driven. The results by compressor type are summarized in Figure 21.

Figure 21 - Comparison of Green House Gas Emissions from One Compressor by Fuel Type

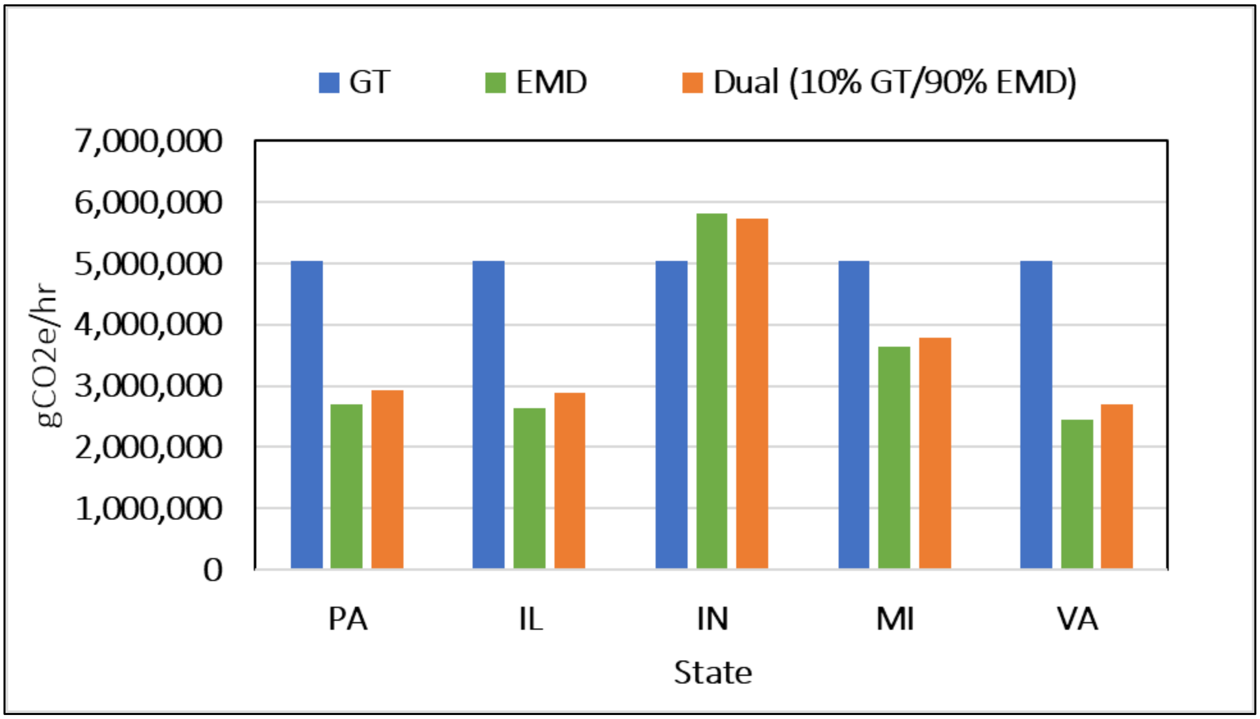


Source: ICF

A GT Driven Compressor had greater GHG emissions than the EMD Compressor. An EMD Compressor reduces emissions by over 40% in comparison to a GT Driven Compressor. The GT/EMD Dual Driven Compressor is assumed to operate 90% of the time on electricity and the remaining 10% of the time on natural gas. One GT Driven Compressor contributes around 6% of the emissions calculated for 1,900 miles of natural gas transmission in pipeline (88,185,389 gCO2e/hr) based on ICF analysis.

The EMD Compressor and GT/EMD Dual Driven Compressor emissions are impacted by grid mix. All three compressor types were compared using the grid mix in five different states. The results are summarized in Figure 22.

Figure 22 - Comparison of Emissions from One Compressor by Fuel Type and State



Source: ICF

In Pennsylvania, Illinois, Michigan and Virgina, the GT Compressor has greater GHG emissions than the EMD Compressor and GT/EMD Dual Driven Compressor. The electricity grid mix in Indiana has an emissions factor double that of Pennsylvania. Due to the greater GHG emissions in the Indiana grid mix, the EMD Compressor has greater GHG emissions than the GT Compressor (5,809,191 gCO2e/hour and 5,032,118 gCO2e/hour, respectively).

7.2 Methane Emissions

As the overall station Scope 1 CO2e emissions exceed 25,000 metric tonnes per annum, the impact of the candidate station upgrades on site methane emissions and the associated IRA methane emission charges needed to be considered in the economic analysis.

Replacement of three older natural gas engine driven 2-stroke reciprocating compressors with a single centrifugal compressor with any of the drive options considered in this study will result in a material reduction in methane fugitive emissions, contributing to development economics, by reducing the methane emission charges at the candidate compressor station.

For this analysis ICF relied on the 2023 EPA GHGI CH4 emission factors for natural gas systems (annex 3.6), which accounts for fugitive emissions for reciprocating and centrifugal compressor with wet and dry seals, exhaust emissions for engines and gas turbines, pneumatic devices, and blowdown/venting emissions.

Typically, the fugitive emissions associated with compressors are primarily from rod packing seals on reciprocating compressors due to wear and tear over time (with increasing emissions over time before replacement), methane leaking through the wet/dry seal and then emissions may come from isolation valves and blowdown valves or other components near the compressor assembly that vibrate and can leak over time. As such, most of these fugitive emissions for the new compressor cases will be the same regardless of drive selected, with the main difference being the combustion (exhaust) emissions for the gas turbine drive versus no exhaust emissions for the motor drive.

ICF attempted to check the above assumption by estimating potential fugitive emissions associated with gas turbine (fuel) piping, fuel coalescer and heater fugitive emissions, fuel heater stack (exhaust) emissions and gas turbine startup and shutdown emissions (for 20 cycles/year) and these estimated fugitive emissions were estimated to be significantly less than the gas turbine normal combustion exhaust emissions.

For the economic analysis ICF accounted for differences in the combustion (exhaust) methane emissions and compressor fugitive emissions excluding pipeline and station venting, flaring and pneumatic devices, for each drive option, using the 2023 EPA GHGI CH4 emission factors. These factors are summarized in Table 13.

Table 13 - 2023 EPA GHGI CH4 Emission Factors

2023 EPA GHGI CH4 Emission Factors		
CH4 Emission	**Units**	**Value**
Reciprocating compressor (fugitive)	kg/yr/compressor	65,000
Centrifugal compressor (dry seals, fugitive)	kg/yr/compressor	44,000
Engine exhaust (transmission)	kg/MMHPhr	2,459.3
Gas turbine exhaust (transmission)	kg/MMHPhr	109.8
Motor drive exhaust (transmission)	kg/MMHPhr	0.0

Source: EPA

8 Economic Proforma Modeling

ICF conducted an economic proforma analysis to compare the three different replacement compressor drive options. The analysis incorporates capital costs, energy costs, federal incentives and other fixed and variable costs. Because the analysis focuses on a single compressor in a larger gas transmission and delivery system, the analysis does not incorporate revenue in the traditional sense. The point at which a natural gas company experiences revenue is at the end of the pipeline, where the gas reaches the end user. Compressors aid in a functioning pipeline, but do not themselves experience revenue. Therefore, the pro forma is essentially a measure of the lifecycle cost of each replacement compressor drive option, measured with a net present value (NPV) calculation. The least negative NPV is the most economical.

8.1 Key Assumptions

To conduct the pro-forma analysis, ICF utilized a series of assumptions which are described here in two categories. First, are base assumptions that are applied to every scenario. Second are market assumptions, which relate to the behavior ICF anticipates market actors to follow.

8.1.1 Base Assumptions

ICF utilized the same assumptions in each of the three cases as outlined in Table 14. Annual inflation is an ICF internal view of long-term inflation. The implicit assumption here is that the U.S. inflation rate will return to a long-term average after experiencing elevated inflation from mid-2021 to mid-2023. Given an initial operating year of 2025 and recent declines in the inflation rate, ICF views this assumption as reasonable. The inflation rate is utilized to show growth in the cost of labor, spare parts, maintenance, electricity, natural gas, and other production inputs. The assumption for capital funded by debt and the depreciation schedule were developed with input from the natural gas industry.

Table 14 - Economic Proforma Assumptions

Economic Proforma Assumptions		
Criteria	Value	Notes
Annual Inflation	2.1%	Reflects US Long Term Average
Capital Funded by Debt	35%	Industry Standard
Debt Term	10 Years	
Depreciation Schedule	20 Year Straight line	Industry Standard
NPV Discount Rate	15%	
Interest Rate	8.5%	
Project Life	20 Years	
First Year of Operation	2025	

Source: ICF

Other key assumptions like the NPV discount rate, debt term length, and corporate interest rate are reflective of the wider economy and are not necessarily specific to the natural gas industry.

8.1.2 Market Assumptions

In this analysis, ICF makes the following assumptions related to the behavior of the natural gas pipeline operator, the market, and the federal government:

- In the Dual Drive scenario, operators can accurately predict the proper time to switch from electricity to natural gas.
- The Federal Government will not change any measures of the IRA as they relate to methane mitigation measures.
- The cost of key inputs will fluctuate only according to inflation.

Dual Drive Fuel Switching

The key benefit of the dual drive option is the ability to switch from electricity to natural gas during the 10% most expensive electricity price hours of the year. This is described in detail in Section 8.6. ICF capped the ability to switch energy types to 10% with the anticipation that utilities and other regulatory entities will set such a limit to switching. This presents the gas utility operator with the difficult task of deciding which hours are the most optimal to switch to natural gas. It is possible the economics will favor a switch to natural gas for more hours than the 10% allowed. In any given hour where gas operation is cheaper, the gas utility will have to determine whether the current hour will be in the 10% most expensive hours of the year, or whether there are future hours that will have a more favorable arbitrage between natural gas and electricity. While utilities in practice are unlikely to execute this task perfectly, ICF made a simplifying assumption that they do. To the extent that this assumption is invalid, the NPV of the dual drive option declines.

Federal Government Policy

The primary government incentives that this analysis incorporates are methane mitigating measures from the IRA. ICF incorporated these incentives based on current law and assume no changes to the law. Over the course of a twenty-year project life span, it is possible that federal policy shifts either more in favor or in opposition to incentives related to mitigating methane emissions which could change the project economics considered in this analysis. While policy change is frequent, it is not a prediction that ICF undertook. Therefore, ICF made a simplifying assumption that federal policy does not change throughout the life of the project.

Cost of Key Inputs

ICF took current prices of key inputs into account for the pro-forma for this analysis. Over time ICF projects that the price of these inputs will increase at the same rate as inflation, which is assumed to be 2.1%. It is possible that certain operating expenses like labor and maintenance change in price at a rate different than inflation. Because forecasting these different price changes is beyond the scope of this analysis, ICF relied on its simplifying assumption related to inflation.

8.2 Capital Costs

The capital costs for each compressor replacement scope, as described previously, is summarized in Table 15.

Table 15 - Capital Costs for Each Replacement Compressor Type

Capital Costs for Each Replacement Compressor Type	
Drive Option for Replacement Compressor	Total Development Cost ($MM)
EMD	27.8
Gas Turbine	24.7
Dual (EMD/GT)	34.6

Source: ICF

The total development costs include compressor and drive package budgetary costs provided by a vendor as well as site development and construction costs estimated.

8.3 Gas and Power Cost Forecasts

To determine the energy costs associated with each technology, ICF utilized internal gas and power forecasts for the different compressor scenarios. Below is a brief description of the forecast models utilized.

8.3.1 ICF's Gas Market Model

ICF's Gas Market Model (GMM) determines the marginal value of natural gas at 121 regional market centers, or nodes. The price is determined by the balance of supply and demand in a regional marketplace.

Demand

Demand for natural gas is modeled for residential, commercial, industrial, power, and export sectors for 121 nodes, factoring the economic growth, weather, and level of price competition between oil and gas in each region. Power sector demand is modeled iteratively with output from the GMM. The price of natural gas influences demand from the power sector which then influences the price of natural gas. The iterative nature of the model enables the GMM to capture this dynamic. Additionally, fuel competition, dispatch decisions, and new power plant construction are incorporated into the industrial and power sector demand for gas.

Supply

Supply is calculated by using production volume from natural gas fields in the lower 48 states, Canadian imports, and LNG imports. Transportation costs and the impact of supply from storage are also incorporated.

Transportation costs model expansion of pipeline capacity using identifiable development plans, such as facilities under construction or that have been filed with FERC. In the long run, pipeline expansions are assumed to continue as demand grows beyond current capacity. The price of pipeline expansions is estimated using regression analysis of Oil and Gas Journal surveys of pipeline projects.

Storage is represented in 24 US states and 2 Canadian storage regions based on historical field level storage capacity. Withdrawals from storage facilities are calculated based on a supply curve which is fit to historical observation.

After the intersection of supply and demand has been determined at the clearing price, delivered price adders are added to the price to better reflect the price of the final product based on local demand and seasonality.

8.3.2 ICF's Electric Power Model

For the analysis, ICF uses an integrated modeling approach across two platforms - Integrated Planning Model (IPM®) and ABB's PROMOD IV. ICF's widely used and accepted Integrated Planning Model (IPM®), a multi-regional, linear programming model of the U.S. electric power sector, is used to generate economic builds and retirements for each PJM load zone, as well as for neighboring ISOs. These builds and retirements are then implemented into ABB's PROMOD IV, a highly detailed electric market simulation model that chronologically computes hour-by-hour production costs while recognizing the constraints on the dispatch of generating units imposed by the transmission system.

In PJM, gas-fired units are marginal for the majority of hours and hence the fluctuations in energy prices closely follow the gas price trends. This is expected to generally remain the case over the forecast, though the link between gas prices, carbon prices, and power prices becomes less strong over time with increasing renewable penetration. Significant amounts of renewable capacity are expected to enter the PJM market over the next 20 years, driven by a combination of improving resource economics and various policy drivers on both the federal and state level. Among the PJM states, Illinois, Maryland, New Jersey, and Virginia have the most aggressive clean energy and renewable energy mandates. While renewable builds are projected across PJM, a large portion of these builds are to be in eastern part of PJM due to these policy mandates. As a result, the price impact from renewables is more pronounced for price points in and around these states, such as Eastern Hub.

In the immediate term, energy prices are inflated due to the recent run-up in commodity prices which are expected to normalize in the near to mid-term, which results in a slight dip in the power prices. Post 2025, as renewable builds enter the market and more specifically significant amount of offshore wind starts to come online in New Jersey and Maryland, the energy prices for Eastern Hub start to decline before they rise in the long term. In the long term, energy prices continue to increase due to increasing gas, carbon prices and the impacts of demand growth and existing resource retirements, also results in a tightening reserve margin over the forecast that puts some upward pressure on the prices.

8.4 Operating and Maintenance Costs

The (average) annual operating costs for each compressor replacement scope is summarized in Table 16.

Table 16 - Average Annual Operating Costs for Each Replacement Compressor Type

Average Annual Operating Costs for Each Replacement Compressor Type	
Drive Option for Replacement Compressor	Average (annual) operating and maintenance cost ($MM/yr)
EMD	0.42
Gas Turbine	0.77
Dual (EMD/GT)	0.45

Source: ICF

These operating and maintenance costs include operating labor costs, budgetary average annualized compressor and drive package maintenance labor and parts costs provided by a vendor. As the gas turbine drive overhaul costs are scheduled based on running hours, the dual drive compressor option has significantly lower average annualized maintenance costs than the gas turbine (only) drive option.

8.5 Environmental Attribute Credits

The IRA, passed in August 2022, provides two primary incentives that are relevant to compressor replacement projects: Incentives for Methane Mitigation and Monitoring (IMMM) (Section 136.a) and the Waste Emissions Charge (Section 136.c). These policies provide both a carrot and stick that encourage investment in methane emission mitigation measures.

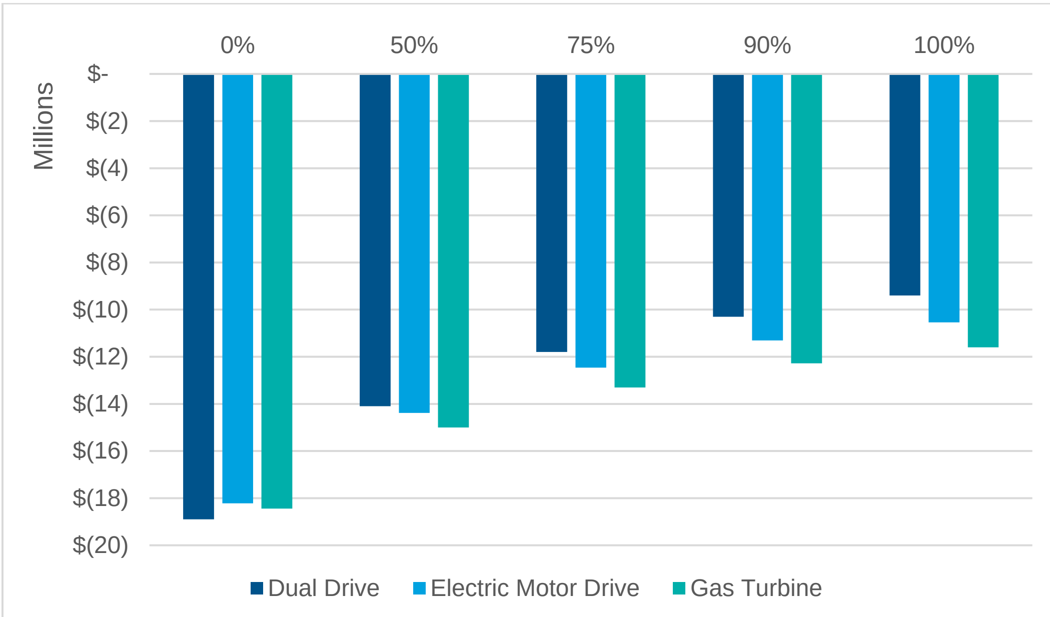
The IMMM is an $850 million pool of money available for grants, rebates, contracts, and loans to provide financial assistance to reduce methane emissions from the natural gas system. One category outlined for use of these funds is “improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions and waste”. For the purposes of this study, ICF assumes that upgrading compressor equipment in the natural gas transmission system will qualify in this section.

The impact of this incentive is reflected in the proforma in the reduction of capital costs. Although details are scant on the process of dispersing these funds, it is possible that pipeline developers and managers who qualify for the funds will receive grants for 90% of the capital costs. This view is based on the level of subsidies received for similar programs such as the investment tax credit. Because the pool of money however is only $850 million, it is possible that the funds either run out or are rationed at lower percentages per project.

To determine the exact level of capital costs that will be covered by the IMMM program, a cost segmentation analysis will likely be required. This analysis would detail the specific capital costs associated with the project and determine which project costs qualify for IRA funds. ICF ran multiple scenarios testing different levels of the capital cost coverage by the program and found that higher rates of coverage by the IRA program make the dual drive option increasingly attractive, as its main downside is its high capital cost. At lower rates of coverage, the electric motor drive and gas turbine option reach parity in terms of NPV.

Given the uncertainty surrounding the IMMM, ICF developed its base case analysis under the assumption that coverage is 0%. This would reflect a scenario where the funds have run out or are being dispersed at low coverage rates per facility.

Figure 23 - NPV at Different Levels of Capital Cost Coverage by the Methane Mitigation and Monitoring Incentive



Technology	NPV at 0%	NPV at 50%	NPV at 75%	NPV at 90%	NPV at 100%
Dual Drive	-$18.9 MM	-$14.1 MM	-$11.8 MM	-$10.3 MM	-$9.4 MM
Electric Motor Drive	-$18.2 MM	-$14.4 MM	-$12.5 MM	-$11.3 MM	-$10.5 MM
Gas Turbine	-$18.4 MM	-$15.0 MM	-$13.3 MM	-$12.3 MM	-$11.6 MM

Source: ICF

The other incentive included in the economic analysis is the Waste Emissions Charge in the IRA, which imposes a charge up to $1,500 per ton of methane emissions for facilities that emit more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases per year. In the text of the IRA, gas transmission compression is specifically listed as an applicable facility to the charge. ICF's conclusion is that natural gas companies will be required to pay this fee for their compressor stations and that efforts to reduce methane emissions at compressor stations will result in savings. Therefore, ICF calculated the expected emissions in the three scenarios and reflected reductions as revenue to the candidate compressor asset financials. All three compressor drive cases significantly reduce methane emissions at the selected compressor station, by replacing multiple older gas engine driven 2-stoke reciprocating compressors with a new single centrifugal compressor with a dry gas seal.

8.6 Results

The results of ICF's financial analysis are summarized in the table below. Given the specific inputs for this case, it appears that in terms of NPV, the electric motor drive is the most attractive option, with an NPV slightly more favorable than the gas turbine option. The two NPVs however, are within a margin of error that it is possible to consider them equal. The Dual Drive option is approximately $0.7MM lower in NPV over the life of the asset than the EMD, primarily due to its high capital cost.

Table 17 - Technology NPV for 20 Year Useful Life, Assuming No Capital Cost Subsidy

Technology NPV for 20 Year Useful Life, Assuming No Capital Cost Subsidy		
Scenario	NPV	Notes
Dual Drive	$-18.9 MM	Main sensitivities between the technologies are capital cost coverage from IRA provisions and energy costs.
Electric Motor Drive	$-18.2 MM	
Gas Turbine	$-18.4 MM	

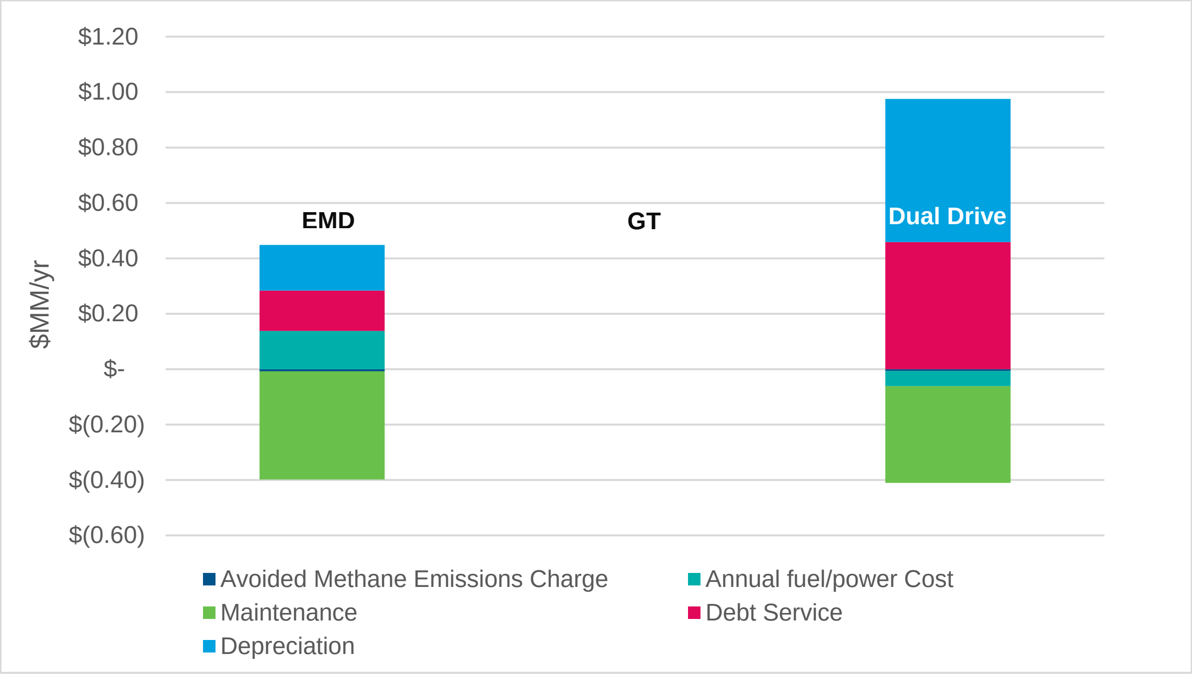
Source: ICF

Decarbonizing the selected compressor station by using an EMD replacement compressor is not anticipated to result in higher lifecycle costs than using a traditional gas turbine driven compressor replacement. Note that this conclusion may not be true for other potential electrification scopes and compressor station locations.

The dual drive replacement compressor achieves most of the carbon reduction benefits of the EMD but also achieves improved gas transmission resiliency, which in this case is anticipated to cost about $700,000 over the life of the asset. It is important to note that this lifecycle cost difference is calculated assuming that no IRA grant funds are available to draw down capital costs. If IRA funds are available, then the dual drive compressor replacement becomes more attractive.

The graph below shows the different contributions to NPV by category net of gas turbine driven replacement compressor option costs. Positive values are costs to the development of the compressor station and result in lower NPV. It is interesting to note that the GT compressor option has financial benefits over the EMD and Dual Drive options in almost every category. Because of its lower capital costs, items like depreciation and debt service are more favorable for the GT. Energy prices are also lower for the GT. Lower maintenance costs are the primary benefit that the EMD and Dual Drive options have over GT. Because debt service is amortized over the life of the asset, the EMD has a slightly improved NPV over the GT. Other costs like operating labor and avoided methane emissions charges are equal or similar enough to not have a major impact on the difference in NPV between the different technologies.

Figure 24 - Contribution to NPV by Category Net of Gas Turbine Costs



Source: ICF

The NPV for each scenario is negative. This is because, in this limited scope, ICF analyzed the economics of a single compressor replacement in the larger gas utility industry. The revenue in a gas utility is not realized until the gas is sold, after passing through many compressors. Therefore, an analysis of a single compressor doesn't have any revenue. What is included in this pro-forma analysis is simply the costs associated with each compressor drive option with cost saving added back from the Avoided Methane Emissions Charge. The negative NPVs listed here do not indicate that switching to an upgraded compressor will result in a financial loss to the company. This analysis is most helpful in comparing the different drive options, where a less negative NPV indicates the most economical drive option.

This analysis also does not represent a comparison to continuing to operate the existing natural gas engine driven reciprocating compressors. Calculations were not performed to show the costs or savings in comparison with a 'business as usual' case.

Capital Costs

Capital Costs are a key sensitivity in the comparison of the three technologies. The dual drive replacement compressor option has capital costs that exceed the GT drive compressor option by roughly $10 million. This increased cost makes the dual drive compressor the least attractive option in most scenarios. When the gas utility is required to fund the investment without government assistance, the dual drive compressor option has a NPV about $.7MM lower than the other scenarios.

If IMMM grant money is available however, this cost is mitigated, and the dual drive replacement compressor becomes a more attractive option. In scenarios where the IRA grant money covers 50% or more of the capital costs, the dual drive replacement compressor option becomes the most attractive in terms of NPV, because the dual drive has benefits in other categories like energy and maintenance costs.

The EMD replacement compressor option has capital costs about $3 million above that of the GT drive compressor. While this does put the EMD at an initial disadvantage, the savings elsewhere on the balance sheet make up for this increased cost and gives the EMD a favorable NPV in comparison to the GT drive.

Energy Costs

Energy costs varied significantly between the three replacement compressor options and are another key sensitivity in the analysis. To find the annual power price for the electric motor drive, ICF took a simple average of hourly prices for a given year and multiplied that price by projected power consumption. Transmission supply charges, fixed and variable distribution charges, peak load contribution (PLC) charges, and capacity charges are also included in the annual power consumption calculation. Tariff rates for these additional charges are from PECO Energy Company and were adjusted for inflation. ICF notes that there is uncertainty surrounding the PLC cost for the development. The utility calculates the PLC for individual load centers every year based on the average peak power consumption system wide during the five highest energy consumption hours during the summer months and the individual load center’s contribution to that peak during those hours. In this analysis, ICF assumed that PLC charges are attributed to the total maximum power consumption for the compressor which is 8200 kW. ICF believes that this captures a worst-case scenario of PLC costs for the EMD and Dual Drive compressor systems.

The gas turbine costs were a simple calculation of the annual forecasted price of natural gas per MMBTU from a node close to thew compressor station multiplied by annual gas consumption. Because gas would be drawn from the pipeline to power the compressor, there are no additional connection or infrastructure costs like the electric motor drive experiences.

The dual drive replacement compressor energy costs incorporate the key assumption that compressor operators will be able to switch from using electricity to pipeline gas when electricity is at its most expensive. Using hourly price forecasts, ICF calculated the average electricity price at the 90th percentile and below for a given year and multiply that price by 90% of the hours used in the electric motor drive scenario. The price of natural gas for that year is then multiplied by the remaining 10% of the hours of operation. The electric power and gas power costs are then added to the total annual energy cost.

The results of the fuel costs follow our hypothesis that the EMD compressor would have the highest energy costs. The dual drive option had lower energy costs than the EMD compressor primarily because it can avoid the most expensive electricity hours by switching to gas. To illustrate this point, the 90th percentile hourly electricity price forecasted for 2025 is $0.76/kWh. The 99th percentile price is $1.58 – more than double the 90th percentile price. Avoiding these major jumps in price is one of the key benefits of the dual drive option over the EMD.

Table 18 - Annual Energy Costs in Millions of Dollars (2025)

Annual Energy Costs (2025) ($MM/yr)	
Dual Drive	1.73
Electric Motor Drive	2.02
Gas Turbine Drive	1.36

Source: ICF

Maintenance and Spare Parts

High maintenance costs is the primary downside of the GT drive compressor option. Most of the other inputs like energy costs and capital costs favored the GT drive option. The annualized maintenance costs for the GT driven compressor option was approximately $350k/yr more than the EMD compressor, due primarily to the costs of periodic scheduled major and minor gas turbine overhauls.

Negative NPV

It is important to view the results in the context of the analysis. Each scenario yields a negative NPV because the pro forma only analyzes the costs and revenues associated with a single compressor, which is itself a one segment of a larger business model. Importantly, no revenue is experienced at the point of compression. The sale of natural gas occurs later in the business model and provides the key revenue associated with the whole system. Thus, the NPVs do not show that investment in a more efficient drive will cause a gas company to lose revenue but show a mitigated cost overtime associated with that efficiency. The analysis also doesn't reflect a loss compared to a business-as-usual case, as that comparison was outside the scope. Rather, these results illustrate the comparative NPV or life cycle costs between the three replacement compressor drive options only. The least negative compressor option will have the lower life cycle costs.

8.7 Conclusions

In this limited review, there are three key conclusions that can be drawn.

- In terms of NPV, the EMD and the gas turbine drive appear very close in lifecycle costs. ICF estimated the NPV of the EMD to be -$18.2 MM and the gas turbine to be -$18.4 MM This means that the incremental cost of compressor electrification versus conventional gas driven compressor(s) is minimal or negative in the case analyzed.
- Also, in terms of NPV, the dual drive compressor option, with an estimated NPV of -$18.9, is relatively close in lifecycle costs to the other two compressor drive options. A primary downside of the EMD compressor option is the potential adverse impact of the gas transmission system resiliency, in times of power outages. In this analysis, it appears that the dual drive compressor option can achieve reduced emissions while addressing the gas transmission resiliency concern at a relatively small incremental increase in the asset life cycle costs.
- The results of this analysis are very dependent on forecast electricity and natural gas prices. ICF's outlook for the eastern Pennsylvania region is that future electricity prices

will not be high enough to make the EMD compressor option prohibitively more expensive to operate than the gas turbine compressor, given the other factors included in the financial analysis. This may be true in eastern Pennsylvania but false elsewhere in the U.S.

9 Electrification Roadmap

9.1 Lifecycle Costs

Pipeline operators must attempt to balance the need to provide reliable and flexible gas supply service to their gas customers with other objectives, including transmission costs, scope 1 emission reductions and overall GHG emission reductions. With regards to compressor station electrification, it is reasonable to ask what the impacts of achieving a certain amount of GHG emission reduction are on the lifecycle costs of the gas transmission system.

Based on the previous economic modeling and carbon intensity scoring, the costs of mitigating a ton of CO_2 by installation of an EMD compressor or a dual drive compressor, versus a gas turbine driven centrifugal compressor are summarized in the following Table:

Table 19 - Cost of Mitigating a Ton of CO2e by Installation of an EMD or a Dual Drive Compressor Versus a GT Driver Compressor

Cost of Mitigating a Ton of CO2e by Installation of an EMD or a Dual Drive Compressor Versus a GT Driver Compressor	
Scenario	$/ton CO2e mitigated (versus GT drive option)
Electric Motor Drive	-$0.7
Dual EMD/GT drive	$2.0

Source: Confidential and ICF

Pipeline companies should then compare the CO2e mitigation costs for a specific compressor station electrification with other GHG reduction initiatives they could potentially implement (e.g., waste heat recovery, hydrogen blending in natural gas, etc.), before proceeding with a compressor electrification program.

The mitigation costs presented in the table above are quite low (or negative in the case of the EMD compressor option) compared with other GHG emission reduction strategies including solar PV or wind power generation and renewable natural gas (RNG) production. Marginal Abatement Cost Curves (MACC) are a useful way of comparing GHG mitigation strategies in order of the lowest to highest GHG mitigation cost and are a useful way to compare multiple potential compression electrification projects at different transmission compressor stations, with other potential GHG mitigation opportunities.

Note that the candidate compressor station in this study was selected and the scope was defined to illustrate that compressor electrification, and the associated GHG reductions, can be achieved at low lifecycle costs. There will be other compressor station locations and projects scopes in which the costs for GHG mitigation are far less favorable, or even where electrification cannot achieve GHG reductions, so it is necessary to consider all of the factors specific to an individual project.

9.2 Emissions

9.2.1 Scope 1 Emissions

A major reason for considering electrification at a gas transmission compressor station may be the reduced local (Scope 1) emissions versus gas driven compressors. This issue may be more significant where gas compression is installed in populated areas and can often simplify the permitting process. These benefits need to be weighed with the other factors discussed in this study before proceeding with an electrification project.

9.2.2 Scope 2 Emissions

Depending on the location of the compressor station being studied, and the available grid power CI, it is possible that an electrification project can reduce Scope 1 GHG emissions, but the associated Scope 2 emissions from the associated power generation exceed the Scope 1 emission reductions, so the available grid power carbon intensity should be reviewed prior to considering compressor electrification, for the purpose of achieving emission reductions.

A more detailed analysis should consider the load profile of the compressor facility, the impacts of ambient temperature on the compressor drive efficiency and the utility power generation and the carbon intensity scores for on and off-peak electricity supply.

9.3 Legislative Considerations

The Inflation Reduction Act

The IRA provides two primary incentives that are relevant to compressor replacement project: the IMMM (Section 136.a) and the Waste Emissions Charge (Section 136.c).

The IMMM is an $850 million pool of money available for grants, rebates, contracts, and loans to provide financial assistance to reduce methane emissions from petroleum and natural gas systems. The statute outlines possible uses of the funds including to “provide financial and technical assistance to reduce methane and other greenhouse gas emissions from petroleum and natural gas systems, mitigate legacy air pollution from petroleum and natural gas systems and provide support for communities.” One sub-category outlined is “improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions and waste”. ICF anticipated that upgrading compressor equipment in the natural gas transmission system will qualify in this section. It should be noted that these limited funds however are open to the wider fossil fuel industry and can be used for more than just upgrading equipment on natural gas pipelines. This could make procuring the funds for upgrading compressors such as are considered in this analysis difficult. Funds are available from FY 2022 to FY 2028.

The other incentive included in the economic analysis is the Waste Emissions Charge in the IRA, which imposes a charge up to $1,500 per ton of methane emissions for facilities that emit more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases per year. The waste emissions charge is set at $900 per ton in 2024, $1,200 per ton in 2025 and $1,500 in 2026 and subsequent years. Applicable facilities include offshore and onshore petroleum and natural gas production, underground natural gas storage, liquified natural gas storage, import and export equipment and Onshore petroleum and natural gas gathering and boosting. Importantly for this analysis, gas transmission compression is also specifically listed as applicable. ICF’s conclusion is that natural gas companies will be required to pay this fee for their compressor stations and that efforts to reduce methane emissions at compressor stations will result in savings. Therefore, ICF calculated the expected emissions in the three scenarios and reflected reductions in this fee as revenue to the project financials. All three compressor drive cases significantly reduce methane emissions at the selected compressor station, by replacing multiple older gas engine driven 2-stoke reciprocating compressors with a new single centrifugal compressor with a dry gas seal.

The EPA Good Neighbor Plan

The pending EPA Good Neighbor Plan (40 CFR Parts 52, 75, 78, and 97) for pipeline transmission of natural gas will require that new or existing large (>1,000 HP) spark ignited reciprocating internal combustion engines, are required to meet specified NO_x emission limits, that in many cases will require the installation of NO_x control equipment. In this study, this Plan does not impact the comparison of the drive options considered, but it may incentivize replacement of the existing gas engine driven reciprocating compressor assets, by avoiding investment in (future) emission control equipment.

9.4 Grid Interconnection

Key considerations for electrifying gas compressor stations include the peak electric power the station will require, the proximity of the station to existing electric grid infrastructure, the type of grid infrastructure in the area, the spare capacity of that grid infrastructure and the reliability of electric supply.

The peak electric demand of a gas compressor station will determine the type of utility infrastructure required to serve the facility, with higher peak demands requiring more robust service installations. At higher peak demand levels, which will typically require high-tension[17] service voltages, a customer-owned substation will need to be constructed on the compressor station site. Also, the timeline for the utility to construct the service installation are more likely to be longer for higher peak demands, as this demand may need to be provided via interconnection to high voltage transmission lines and/or the capacity constraints on the electrical infrastructure takes longer to study.

The proximity of the compressor station to electrical infrastructure will dictate if and for what distance new electric transmission or distribution overhead power lines and towers will need to be installed. Siting of this equipment may have land use impacts during construction and operation, in addition to potentially significantly impacting the overall development costs. Use of existing rights-of-way for provision of new electrical service eliminates many of the issues associated with land use impacts.

In some circumstances, utilities will install new infrastructure to connect commercial or industrial customers at no cost to the customer, but the particular circumstances are dependent on the specific electric utility, the distance to existing infrastructure, and the potential demand. In this case, the utilities electric customers will have to pay for the new transmission line(s), via a

[17] High-tension service generally refers to service voltages above 600 volts.

surcharge in their electric bill, which will need to be approved by regulators, resulting in additional potential development delays.

The type of infrastructure near compressor station will also influence the type of service, timeline, and cost. The simplest and least costly case is one in which there is nearby infrastructure, whether transmission or distribution, which is appropriate for serving the compressor station peak demand. However, in some cases, there will be a mismatch between the compressor station peak demand and the nearest available infrastructure such as when the station demand is suitable for low-voltage service and the nearest infrastructure is high-voltage transmission or the station demand is above 7,000 kW and the nearest infrastructure is 4 kV distribution. In these types of circumstances, costs will be higher, and timelines will be longer as the utility will need to do more work to extend the appropriate infrastructure. It is also important to note that the nearest transmission line to a compression facility may not be owned by the local utility and may in fact be a transmission line that traverses the territory, requiring the pipeline operator to negotiate with the transmission owner and not the local utility.

9.5 Grid Congestion

The spare capacity of the electrical grid will also impact the cost and timeline for electrification. Some utility grids will have sufficient spare capacity to support the additional electrical load from compression while others will require significant upgrades which will be on a timeline at the utility's discretion and may take up to a year or more. As mentioned above, costs will likely be borne by the electric utility ratepayers, but the particular circumstances are dependent on the specific electric utility.

Note that ISOs and RTOs are required to post heat maps[18] of available grid capacity and to provide tools[19] to allow the developers to assess available grid capacity, for potential interconnections. These publicly available tools are useful for a screening assessment of grid congestion at a particular location or on a specific transmission line.

9.6 Grid Reliability

The reliability of the local electric grid is also an important consideration in electrification in that operators may choose more robust or redundant electric service connections for compressor stations in lower reliability areas. ICF assembled electric reliability data for the year 2021 and 2022 from the U.S. Energy Information Administration Annual Electric Power Industry Report (Form EIA-861), which compiles data from distribution utilities and power marketers of electricity, including reliability performance data. The reliability metric chosen for this analysis is the System Average Interruption Duration Index (SAIDI) which is a measure of the annual average number of minutes of interruption for customers served by a utility. A lower SAIDI value indicates better reliability. Utilities typically report SAIDI with and without "major events" such as storms or hurricanes. ICF chose to use SAIDI values that include major events to reflect the reality of service levels that may be experienced in an electrified future. Note that the reliability statistics in the EIA

[18] MISO POI Analysis Tool: https://giqueue.misoenergy.org/poianalysis/index.html

[19] PJM queue scope tool: https://queuescope.pjm.com/queuescope/pages/public/evaluator.jsf

data set are for local utility supply and will reflect both distribution and transmission caused outages.

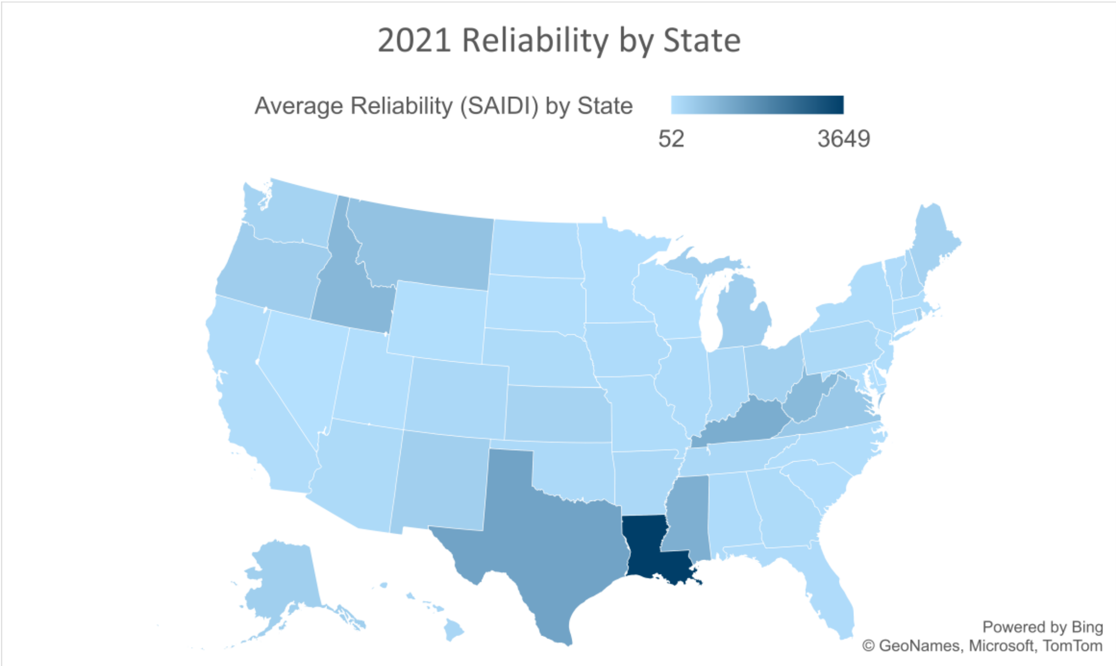
The EIA data set contained data for 803 utilities including investor owned, municipal, cooperative, and political subdivision utilities. The average SAIDI was 352 minutes of outage per customer, with the high of 10,613 minutes and the low of zero minutes.

Figure 25 and Figure 26 show heat maps of 2021 and 2022 reliability (SAIDI) at the state level. ICF used two years' data in order to capture a snapshot of the potential variability of reliability that might be experienced by operators. The 2021 map shows Texas and Louisiana as outliers which is the result of Winter Storm Uri and Hurricane Ida which caused significant damage to the energy systems in those states, while the 2022 map shows the effects of Winter Storm Elliot on North Dakota, Maine, and other sections of the East Coast. ICF's ranking of PJM as the second most reliable ISO after CAISO, was based on this data.

At the level of the individual utility, ICF grouped utilities into quartiles and averaged the performance in each quartile, as shown in Figure 27. The average SAIDI of the utilities in the least reliable quartile is six times more likely to experience a serious outage than the next quartile.

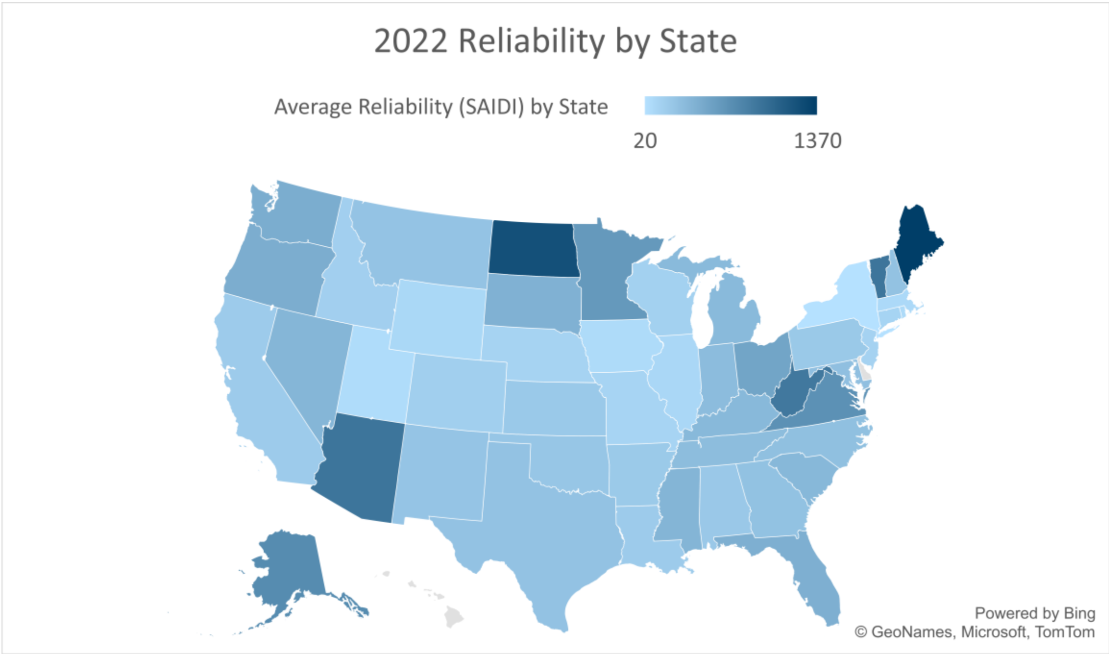
These data imply that there are some regions and electric utilities that could provide much less reliable electricity service than others, and that should be considered when converting natural gas compressor stations to electricity. Regions or utilities that have less reliable electricity service may be at a greater risk of not being able to provide constant service. Additionally, outages at natural gas pipeline compressors could lead to loss of natural gas supply at power generation facilities, as was experienced during Winter Storm Uri and Winter Storm Elliot, which could create a feedback loop in which more compressors lose their electricity supply.

Figure 25 - Heat Map of 2021 Reliability by State according to SAIDI Index



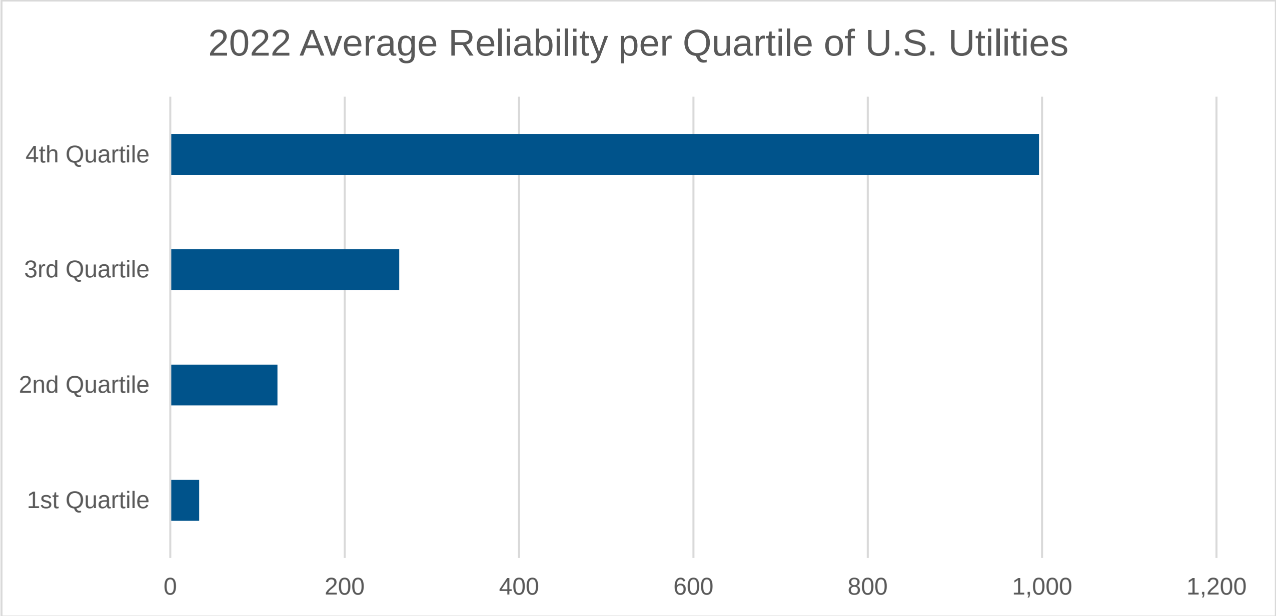
Source: 2021 SAIDI, U.S. Electric Utilities

Figure 26 - Heat Map of 2022 Reliability by State according to SAIDI Index



Source: 2022 SAIDI, U.S. Electric Utilities

Figure 27 - 2022 Average Reliability per Quartile of U.S. Utilities



Source: 2022 SAIDI, U.S. Electric Utilities

The NERC 2022 State of Reliability Report[20] identifies multiple challenges to maintaining grid reliability including: cold and extreme weather events, climate change, electricity and natural gas interdependencies, cyber and physical security, and increased deployment of renewable power generation. Each of these potential issues should be included in a review of grid reliability for a potential electrification project. The same report states that "reliable electric power supply is often required to ensure uninterrupted delivery of natural gas to these balancing resources, particularly in areas where penetration levels of renewable generation resources are highest" and recommends studies to model plausible and extreme natural gas disruptions and studies for planning and operations to ensure energy resource adequacy.

9.7 Permitting

The major consideration when comparing the drive options is that EMDs have the potential to significantly reduce development timelines by reducing FERC review and permitting durations. By eliminating the project scope 1 exhaust emissions, a project New Source Review (NSR) would not be required and there would not be any impacts on the overall site Title V operating permit and the site's GHG Reporting Rule requirements.

Reduced site criteria pollutant and GHG emissions has the potential to avoid requirements for site offset projects and/or purchase of offset credits.

Installation of the EMD drive eliminates (local) scope 1 air emissions, associated with the gas turbine drive, but scope 1 and 2 emissions need to be considered to determine if the EMD option results in overall lower (regional) emissions. Scope 2 emissions associated with the EMD option will largely depend on the energy mix for the local grid power supply. In addition to GHG emissions, scope 1 and 2 emissions for criteria pollutants should also be compared.

Scope 1 emissions of criteria pollutants associated with the gas turbine drive will result in higher local ground level concentrations, but it would not normally be anticipated that these emissions would be particularly significant and/or exceed national ambient air quality standards (NAAQS) threshold values. This issue will be more significant in non-attainment areas, where NAAQS standards are already not being met in some respect.

The EMD drive would generally be expected to generate less noise than the gas turbine drive, due to the elimination of air inlet and exhaust noise, although the gas turbine noise would generally be expected to meet noise limits for the property boundary and/or noise sensitive areas (NSAs), in most cases.

The site visual impacts of an EMD driven compressor are expected to be less than for a GT driven compressor, due to the elimination of the GT air intakes and exhaust stack, although visual impacts at the compressor station site for either option would normally be considered minimal. The visual impacts associated with any new electrical transmission lines and poles also need to be considered.

[20] NERC, 2022 State of Reliability, July 2022.
https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf

As described earlier, potential benefits in permitting duration and costs, for compressor electrification versus natural gas driven compression equipment need to be balanced with other issues discussed in this study.

9.8 Gas Transmission Resiliency

The interdependence of the gas and electric grid have contributed to major electric system emergencies[21]. When considering the electrification of compressor assets, an assessment as to the potential adverse impacts on the gas transmission (and electric system) resiliency in case of a major power outage should be conducted. The assessment should include consideration of the following factors:

- Dependence of gas transmission on electrically driven compression and understanding whether compression facilities have firm or interruptible electrical power supply.
- Extent of grid power generation from delivered natural gas and ability for power generators to fuel switch.
- Availability and location of redundant natural gas driven compressors.
- Potential duration of power outage, including for major weather events or natural hazards (e.g., winter storms).
- Pipeline system features including; gas supply and usage, spare pipeline supply capacity, gas storage, pipeline pressure and line pack.
- Potential for a power outage to result in gas curtailment to electric generator(s), that would significantly exacerbate the extent of the power outage.

As discussed previously, pipelines companies must attempt to balance the need to provide reliable and flexible gas supply service to their gas customers with other objectives, including transmission costs, scope 1 emissions and overall GHG emissions. Although there are no regulated redundancy or resiliency requirements in gas transmission, the pipeline companies will prioritize maintaining reliable gas supply, where mitigating the adverse impacts of the interdependence of the gas and electric grid, for compressor electrification projects, is not practical or sufficient.

The North American Electric Reliability Corporation (NERC)[22] has identified that the electricity and natural gas interdependencies are no longer just an emerging risk, but now requires specific implementation of mitigating strategies. NERC[23] has also recommended risk mitigations for addressing Critical Infrastructure Interdependencies (CII) associated with natural gas transmission including assessments that address natural gas availability and pipeline common mode failures.

[21] How Vulnerable are US Natural Gas Pipelines to Electric Outages, Smillie S. et al, The Electricity Journal, 36, 2023.
[22] NERC, 2022 State of Reliability, July 2022
[23] NERC, 2021 ERO Reliability Risk Priorities Report, Aug 2021

The dual drive compressor option, with both an EMD and gas turbine drive, was included in this study scope as a means of potentially addressing gas transmission resiliency issues, albeit at a significantly higher capital cost.

9.9 Operational Flexibility

This study has selected an electric (induction) motor with variable frequency drive (VFD) to address potential issues with the compressor operational flexibility and motor starting requirements. Analysis of the specific compressor load requirements would normally be required to assess the required operational flexibility and hence the load controls required. In some cases, a cheaper fixed speed motor drive may be adequate, where the compressor load is relatively steady, which will have a significant impact on the installed cost of the EMD compressor option, likely resulting in the compressor cost being at or below the gas turbine drive compressor option.

9.10 Compressor Reliability

The operational reliability of each compressor option is assumed to be equivalent in this analysis, although there is data[24] to indicate that an EMD drive compressor will have a significantly higher mean time between failures (MTBF) and reduced repair time versus a gas turbine drive. The gas turbine drive compressor will also require more frequent and extended scheduled maintenance, although this is typically planned so impacts of the compressor outage are minimized. The increased maintenance costs for a gas turbine driven compressor versus an EMD compressor has been included in the financial analysis.

9.11 Corporate, Government and Industry Considerations

Numerous pipeline companies have established both short-term and long-term internal corporate objectives aimed at a substantial reduction in carbon emissions throughout their extensive pipeline networks. These commitments are not only in alignment with external legislative mandates but also resonate with the considerations of external stakeholders.

Beyond their internal directives, pipeline companies are strategically embracing electrification programs in concert with their pledge to adhere to their Nationally Determined Contributions (NDCs) as outlined in the 2012 Paris Agreement which is reinforced by President Biden's 2030 Greenhouse Gas Pollution Reduction Target. This target aims to reduce economy-wide net greenhouse gas emissions 50-52 percent goal by 2030, measured against 2005 levels.

Additionally, natural gas pipeline companies have embraced industry-wide sustainability targets. These commitments are explicitly delineated by The Interstate Natural Gas Association of America (INGAA) in its climate change commitments, which detail a comprehensive mission dedicated to combating climate change. INGAA's climate change commitment includes a collaborative industry-wide effort to achieve net-zero greenhouse gas (GHG) emissions from natural gas transmission and storage by the year 2050. Many pipeline operators have set near and long term internal corporate goals of reducing carbon emissions across their pipeline network in alignment with external legislative goals and stakeholder considerations. This includes

[24] https://www.tmeic.com/sites/default/files/assets/files/Oil-Gas%20Brochure%20I-5002%20June2021-web.pdf

replacement of end-of-life compressor stations and facilities as well as reducing pipeline leaks and including diversifying their business to include renewables.

For publicly traded natural gas pipeline companies, Environmental, Social, and Governance (“ESG”) and climate scoring are key considerations in decarbonization of their pipeline network which includes electrification of compressor stations. The most popular metric is known as the CDP score. CDP is a not-for-profit charity that runs the global disclosure system for investors, companies, cities, states, and regions to manage their environmental impacts. CDP evaluates over 23,000 companies representing two thirds of global market capitalization. CDP implements is a scoring evaluation matrix which evaluates company supplied information for annual reporting and their environmental leadership. This climate change evaluation includes the verification of Scope 1, 2 and Scope 3 emissions amongst other framework considerations.

9.12 Electrification Decision Making Diagram

A number of the considerations discussed above are summarized in the frameworks included in Appendix D and E. ICF has included two representative frameworks that will support the development of an electrification strategy for a natural gas pipeline operator. These frameworks serve as essential tools to guide and facilitate the electrification of assets. It’s worth noting that electrification may not be a universally applicable solution. As such, these frameworks are intended to be synergistically employed, enabling natural gas pipeline operators to judiciously determine the optimal timing and approach for electrifying their compressor stations within their asset portfolio.

The first framework, the corporate electrification framework provides a strategic blueprint for pipeline operators, enabling them to scrutinize their current portfolio and identify the largest opportunities for electrification using a scoring matrix. This analysis is driven by three focal point: firstly, electrification with the overarching corporate objectives, secondly, by prioritizing capital projects and lastly by capitalizing on methane reduction underpinned by external variables and legislative opportunities. The outcome of employing the framework can aid the identification of key focus regions and the selection of candidate compressor stations as demonstrated in sections 5 and 6 of this study.

The site-specific electrification decision framework is designed to help natural gas pipeline operators navigate how to develop a candidate compressor station identified for electrification. This framework prioritizes: (i) the grid interconnection, (ii) gas transmission resiliency and (iii) permitting. As these factors can introduce long-term risks and can introduce development delays, it is critical to have a clear line of sight in resolving concerns prior to further investments. If the issues are not adequately addressed or acceptable in this initial evaluation the design needs to be rescoped. Based on the gas transmission resiliency analysis, the operator may consider if dual drive compressors are an acceptable solution for that specific candidate compressor stations.

9.13 Other Considerations

Each compressor station is unique regarding its potential to be considered for electrification of natural gas compression due to a large number of factors, including access to the necessary grid interconnection and potentially adverse impacts on the power grid and gas transmission systems resiliency.

Marginal Abatement Cost Curves (MACC) are a useful way of comparing GHG mitigation strategies in order of the lowest to highest GHG mitigation cost and are a useful way to compare multiple potential compression electrification projects at different transmission compressor stations, with other potential GHG mitigation projects.

Prioritizing which compressor stations to first electrify, engaging electric utilities, and identifying site requirements are several key steps required to move towards electrification of the existing and new natural gas transmission compression infrastructure.

As summarized in Section 3, the 80 gas-fired compressor stations with the lowest peak demand are likely the easiest to electrify and could allow for quick implementation. Within that group of stations, those stations closest to existing distribution infrastructure would be the lowest cost and fastest to electrify.

The next group of compressor stations could be prioritized by increasing demand, proximity to electricity transmission and distribution infrastructure and the reliability of the local electric utility distribution grid. However, without further analysis, it is not possible to know the exact type of infrastructure, whether that infrastructure is suitable for serving a particular site and whether there is sufficient spare capacity in the existing grid to serve the demand of the compressor station.

Engaging electric utilities and potentially regulators will be an important part of moving towards electrification. Given the projected growth in demand, it would seem prudent, particularly in states such as Louisiana, Mississippi, and Nebraska, where the projected gas compression demand is significant relative to state demand, to begin to engage regulators and utilities to inform them of the potential impact on demand.

The local electric utility will need to be engaged early in the process. The local utility will determine whether the existing transmission or distribution system can supply the station without upgrades and if upgrades are required, what those will cost. The local utility will also determine the type of service connection they will provide for supplying the compressor station.

According to the U.S. Energy Information Administration's electric power sector survey data[25], there are nearly 3,000 utilities in the U.S. EIA classifies utilities into three ownership types: investor-owned utilities, publicly run or managed utilities, and cooperatives. Although there are only about 168 investor-owned electric utilities, they serve nearly 75% of customers. Publicly owned utilities include federal, state, and municipal electric utilities and number around 1,958. Cooperatives (co-ops) are not-for-profit member-owned electric utilities, number around 812. Every utility will have somewhat different planning processes based on the specifics of the utility. As a result, the requirements for a given compression electrification location will be very situationally specific and may vary widely from utility to utility.

For each compressor station, the specific site requirements will need to be identified to fully prioritize and plan a roadmap for electrification of compression. The pipeline operator or an engineering firm will need to determine the electrical load requirements for the facility. The type of service connection will need to be identified by the local utility and will determine the electric infrastructure requirements on the compression site. As mentioned above, if high-voltage

[25] Data from the 2017 survey.

transmission is the nearest and appropriate infrastructure to connect to, it may not actually be owned by the local utility. Service reliability is also very locationally specific, and the local utility should be able to provide service reliability data, although, since high-level reliability statistics may hide commercial and industrial customer reliability, further analysis may be required to project the reliability specific service configurations.

Depending on projected reliability, operators may choose to use dual-drive technology which provides a backup in the event of loss of electric supply or may decide to pay the additional cost for a more robust electric service from the utility such as a dual supply from two independent sources.

10 Conclusions

The need for incremental interstate natural gas pipeline infrastructure, and thus additional interstate natural gas compression is projected to continue to increase through 2029, driven by growing demand over the next ten years for industrial/petrochemical use, power generation, and exports. To meet demand across all sectors between 2029 and 2045, ICF forecasts natural gas compression capacity requirements in each electric independent system operator (ISO) and regional transmission organization (RTO) region will increase or remain close to 2029 levels. Peak day and peak month utilization, and thus peak period compression requirements are projected to increase faster than the annual average. As a result, existing interstate natural gas pipeline compression, whether gas-fired or electric-powered would still need to be retained for the duration of the forecast horizon. Peak day pipeline utilization, which drives energy system planning, in all ISO/RTO regions at times reaches 100% which means meeting any additional demand would require additional compression capacity.

In many ISOs, including the three ISOs with the largest peak demand requirements – PJM, MISO, and ERCOT – the additional electrical generation and transmission infrastructure required to meet the additional demand likely would require significant development time and investment. This demand growth also could occur at the same time as other sectors electrify traditional fossil applications, such as use of electric vehicles and in building heating. The power infrastructure requirements may be further expanded with additional backup generation to ensure reliability and resiliency of electric compressors in the event of grid outages.

The potentially added electricity demand from converting gas-fired compressor stations to electric motor-driven compressor stations could increase the 2030 peak-demand growth as currently forecasted. For example, electrifying all gas-fired compression in NYISO could cause an increase from the current (2022) forecasted change in electricity peak demand between 2023 and 2030, -334 MW (reduced demand), to an increase of 84 MW. ERCOT and CAISO have less pronounced increases, but the concentration of demand increases in sub-geographies within the ISO could place stress on electric transmission and distribution systems in these sub-geographies.

The assessment and proforma analysis of electrification of a representative compressor station determined that, at some compressor stations, installation of dual-drive compression can achieve significant GHG reductions versus installation of equivalent natural gas only-driven compressors, while not adversely impacting the reliability and resiliency of the natural gas transmission system, at a relatively small increased lifecycle cost. In this case, both the higher capital and energy cost of the dual-drive compressor can be partially offset by the dual-drive compressor’s flexibility to operate on natural gas during peak power cost periods and by reduced annual maintenance costs versus gas turbine (only) driven compressors.

Replacement of older natural gas driven compressors, at the end of their service life, is the opportune time for operators to consider compressor electrification. When considering the electrification of compressors, an assessment of the potential adverse impacts on the reliability and resiliency of the gas transmission (and electric system), such as the potential for electric power outages, must be examined.

ICF included two representative frameworks that will support the development of an electrification strategy for a natural gas pipeline operator. It is worth noting that electrification may not be a universally applicable solution. As such, these frameworks are intended to be synergistically employed, enabling natural gas pipeline operators to judiciously determine the optimal timing and approach for electrifying their compressor stations within their asset portfolio.

Appendix A: Economic Proforma Model

In addition to a written description of the Proforma assumptions and methodology, summary tables of the three technology types are provided below. ICF only selects reference years, but all revenue and cost inputs are included.

EMD Simplified Pro-Forma

Key Inputs				
Availability		93.00%	Annual Operating Hours	6000.0
Annual Inflation Assumption		2.1%	Debt Service Level	35%
NPV Discount Rate		15.0%		
Total Capital Cost	$	27,874.45		
Cash from Lenders	$	9,756.06		
Funds Available in Year 0	$	(18,118.39)		

Simplified ProForma	Units	2025	2026	2027	2030	2035	2040	2045
Operating Revenue								
Waste Emissions Charge Avoidance	($000), nominal	$ 527.42	$ 659.28	$ 659.28	$ 659.28	$ 659.28	$ 659.28	$ 659.28
Total Revenue	($000), nominal	$ 527.42	$ 659.28	$ 659.28	$ 659.28	$ 659.28	$ 659.28	$ 659.28
Fixed and Variable Costs								
Annual Energy Costs	($000), nominal	$ 2,020.01	$ 1,870.50	$ 1,718.90	$ 1,332.29	$ 1,891.38	$ 2,699.67	$ 3,400.37
Maintenance	($000), nominal	$ 116.42	$ 118.86	$ 121.36	$ 129.16	$ 143.31	$ 159.00	$ 176.41
Labor	($000), nominal	$ 300.00	$ 306.30	$ 312.73	$ 332.85	$ 369.30	$ 409.74	$ 454.61
Total Variable Costs	($000), nominal	$ 2,436.42	$ 2,295.66	$ 2,152.99	$ 1,794.30	$ 2,403.99	$ 3,268.41	$ 4,031.39
EBITDA	($000), nominal	$ (1,909.00)	$ (1,636.38)	$ (1,493.71)	$ (1,135.02)	$ (1,744.71)	$ (2,609.13)	$ (3,372.11)
Annual Debt Service	($000), nominal	$ 1,804.87	$ 2,014.63	$ 1,516.58	$ 1,381.95	$ -	$ -	$ -
Depreciation	($000), nominal	$ 1,045.29	$ 2,012.26	$ 1,861.18	$ 1,473.16	$ 1,243.76	$ 1,243.48	$ 621.88
Funds Avaialble before Taxes	($000), nominal	$ (3,713.87)	$ (3,651.01)	$ (3,010.29)	$ (2,516.97)	$ (1,744.71)	$ (2,609.13)	$ (3,372.11)
After Tax NPV:	($18,219.50)							

Gas Turbine Simplified Pro-Forma

Key Inputs								
Production Availability		93.00%	Annual Operating Hours	6000.0				
Annual Inflation Assumption		2.1%	Debt Service Level	35%				
NPV Discount Rate		15.0%						
Total Capital Cost	$	24,734.78						
Cash from Lenders	$	8,657.17						
Funds Available in Year 0	$	(16,077.60)						
Simplified ProForma								
	Units	2025	2026	2027	2030	2035	2040	2045
Operating Revenue								
Waste Emissions Charge Avoidance	($000), nominal	$ 521.04	$ 651.30	$ 651.30	$ 651.30	$ 651.30	$ 651.30	$ 651.30
Total Revenue	($000), nominal	$ 521.04	$ 651.30	$ 651.30	$ 651.30	$ 651.30	$ 651.30	$ 651.30
Fixed and Variable Costs								
Annual Energy Costs	($000), nominal	$ 1,360.85	$ 1,429.91	$ 1,474.59	$ 1,498.97	$ 1,799.57	$ 2,315.48	$ 2,567.34
Maintenance	($000), nominal	$ 467.52	$ 477.34	$ 487.36	$ 518.72	$ 575.52	$ 638.54	$ 708.46
Labor	($000), nominal	$ 300.00	$ 306.30	$ 312.73	$ 332.85	$ 369.30	$ 409.74	$ 454.61
Total Variable Costs	($000), nominal	$ 2,128.37	$ 2,213.55	$ 2,274.69	$ 2,350.53	$ 2,744.39	$ 3,363.76	$ 3,730.41
EBITDA	($000), nominal	$ (1,607.33)	$(1,562.25)	$ (1,623.39)	$ (1,699.23)	$ (2,093.09)	$ (2,712.46)	$(3,079.10)
Annual Debt Service	($000), nominal	$ 1,601.58	$ 1,787.71	$ 1,345.76	$ 1,226.29	$ -	$ -	$ -
Depreciation	($000), nominal	$927.55	$1,785.60	$1,651.54	$1,307.23	$1,103.67	$1,103.42	$551.83
Funds Avaialble before Taxes	($000), nominal	$ (3,208.91)	$(3,349.95)	$ (2,969.15)	$ (2,925.52)	$ (2,093.09)	$ (2,712.46)	$(3,079.10)
After Tax NPV:		($18,411.00)						

Dual Drive Simplified Pro-Forma

Key Inputs								
Production Availability		93.00%	Annual Operating Hours	6000.0				
Annual Inflation Assumption		2.1%	Debt Service Level	35%				
NPV Discount Rate		15.0%						
Total Capital Cost	$	34,602.26						
Cash from Lenders	$	12,110.79						
Funds Available in Year 0	$	(22,491.47)						
Simplified ProForma								
	Units	2025	2026	2027	2030	2035	2040	2045
Operating Revenue								
Waste Emissions Charge Avoidance	($000), nominal	$ 526.79	$ 658.48	$ 658.48	$ 658.48	$ 658.48	$ 658.48	$ 658.48
Total Revenue	($000), nominal	$ 526.79	$ 658.48	$ 658.48	$ 658.48	$ 658.48	$ 658.48	$ 658.48
Fixed and Variable Costs								
Annual Energy Costs	($000), nominal	$ 1,726.41	$ 1,646.27	$ 1,536.69	$ 1,207.79	$ 1,643.57	$ 2,312.57	$ 2,837.39
Maintenance	($000), nominal	$ 153.40	$ 156.62	$ 159.91	$ 170.20	$ 188.84	$ 209.52	$ 232.46
Labor	($000), nominal	$ 300.00	$ 306.30	$ 312.73	$ 332.85	$ 369.30	$ 409.74	$ 454.61
Total Variable Costs	($000), nominal	$ 2,179.82	$ 2,109.20	$ 2,009.34	$ 1,710.84	$ 2,201.70	$ 2,931.83	$ 3,524.46
EBITDA	($000), nominal	$ (1,653.03)	$ (1,450.72)	$ (1,350.86)	$ (1,052.36)	$ (1,543.22)	$ (2,273.34)	$ (2,865.98)
Annual Debt Service	($000), nominal	$ 2,240.50	$ 2,500.88	$ 1,882.62	$ 1,715.49	$ -	$ -	$ -
Depreciation	($000), nominal	$1,297.58	$2,497.94	$2,310.39	$1,828.73	$1,543.95	$1,543.61	$771.98
Funds Avaialble before Taxes	($000), nominal	$ (3,893.53)	$ (3,951.59)	$ (3,233.48)	$ (2,767.85)	$ (1,543.22)	$ (2,273.34)	$ (2,865.98)
After Tax NPV:		($18,907.17)						

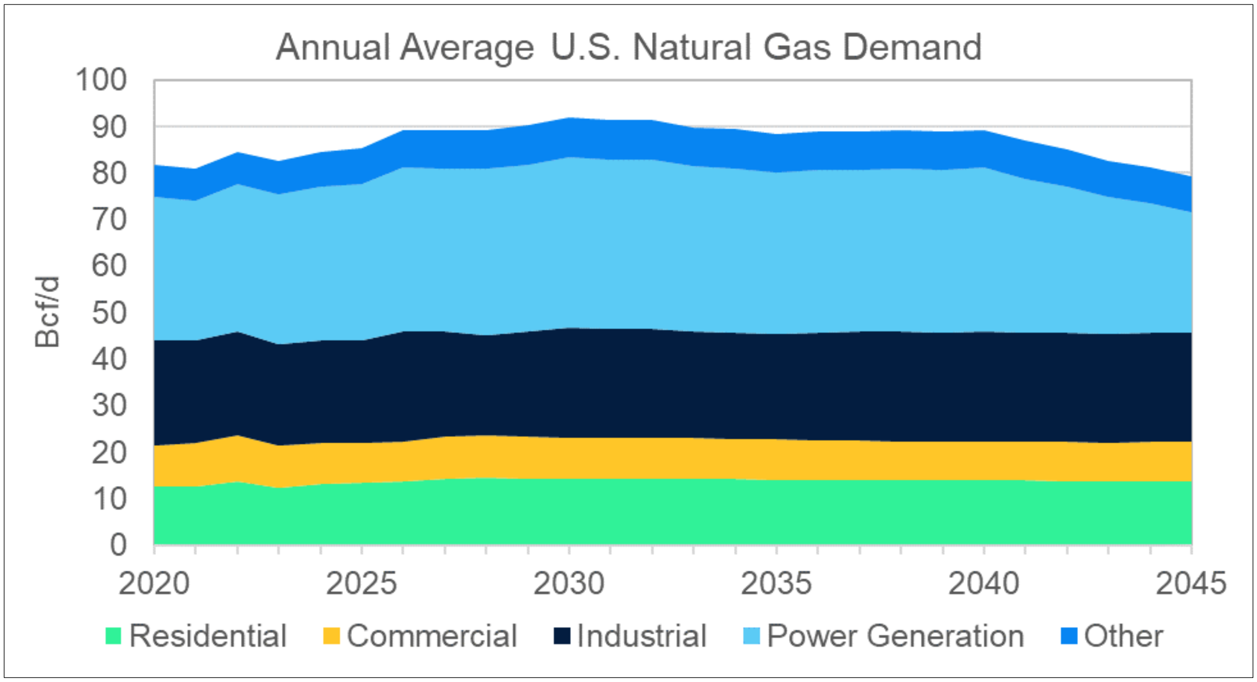
Appendix B: ICF's Natural Gas Market Forecast

This appendix summarizes ICF's Q3 2023 base case North American natural gas markets forecast to estimate future interstate pipeline compression requirements.

The projection of compression capacity needs over the near term (next five years) and the long term (between 2023 and 2045) used in this study was based on the ICF Q3 2023 Gas Market Model (GMM) base case forecast for North American natural gas markets. While U.S. natural gas demand for domestic use and exports will continue to grow throughout the 2020s, today's existing pipeline and compression capacity will continue to comprise the majority of gas pipeline infrastructure in the U.S. for the next few decades. Additionally, the need for incremental interstate natural gas pipeline infrastructure, and thus additional interstate natural gas compression, will be driven by growing demand over the next decade for industrial/petrochemical use, power generation, and exports. Thus, the need for interstate natural gas pipeline infrastructure and natural gas pipeline compression capacity is not only projected to continue, but also grow. Peak day and peak month utilization, and thus peak period compression requirements are projected to increase faster than the annual average. As a result, interstate natural gas pipeline compression, whether gas-fired or electric-powered will still require maintenance for the duration of the forecast horizon of this study. A detailed description of current and forecasted U.S. natural gas demand and energy requirements for interstate natural gas pipeline compression can be found in Appendix B.

As shown in Figure 28, natural gas demand from the power generation sector grows from an annual average level of about 32.1 billion cubic feet per day (Bcf/d) in 2023 and peaks in 2030 at of 36.7 Bcf/d in the forecast. Industrial demand continues to grow throughout the forecast from about 21.9 Bcf/d in 2023 to 23.6 Bcf/d in 2045. Residential and commercial demand, which are about 21.4 Bcf/d in 2023, peak in 2029 at 23.6 Bcf/d and then decline slightly between 2030 and 2045 to 22.1 Bcf/d. The regions of the country that experience growth in domestic natural gas demand and thus will need additional natural gas infrastructure are the Midwest, Texas, Mountain, and Southeast regions. U.S. total domestic natural gas demand is projected to peak in 2030 at an annual average of 92.0 Bcf/d.

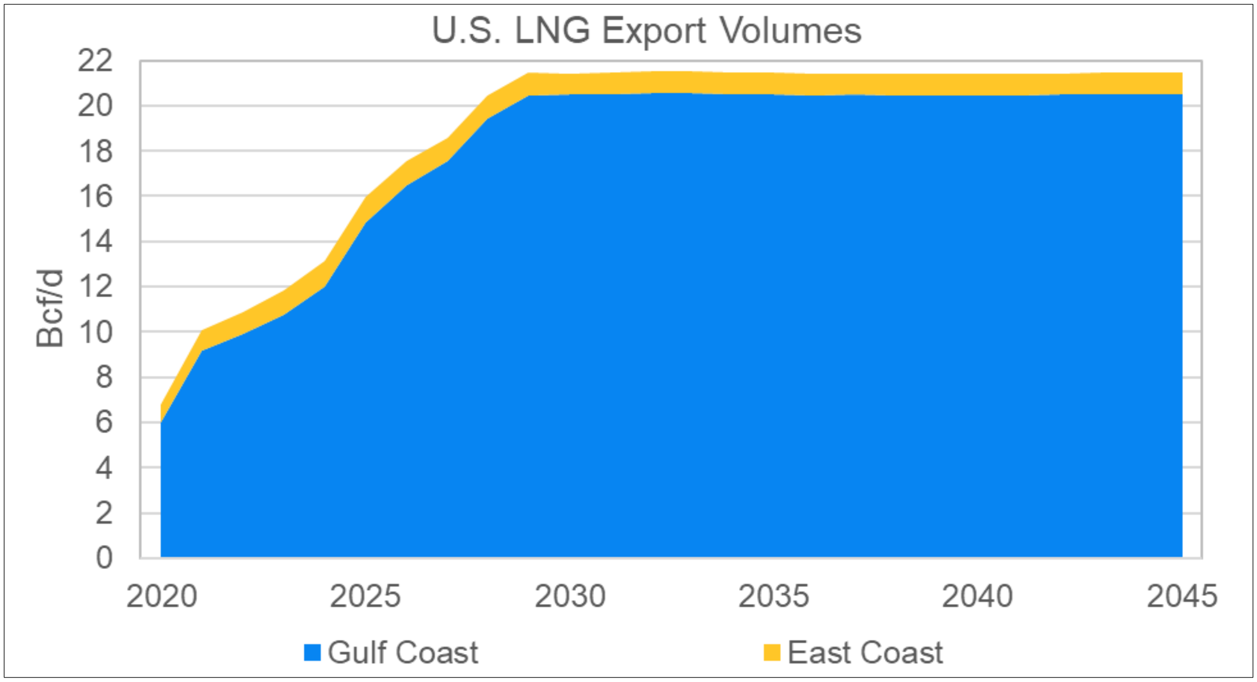
Figure 28 - U.S. Forecasted Domestic Demand



Source: ICF Q3 2023 Base Case Gas Market Forecast

Liquified natural gas (LNG) exports from the Gulf Coast experience significant growth in the forecast. While LNG exports from the East Coast remain constant at about 1.0 Bcf/d, LNG exports from the Gulf Coast in Louisiana and Texas increase from 10.7 Bcf/d in 2023 to 14.9 Bcf/d in 2025 and then 20.5 Bcf/d in 2030. Gulf Coast LNG exports are projected to remain roughly constant at about 20.5 Bcf/d for the remainder of the forecast horizon.

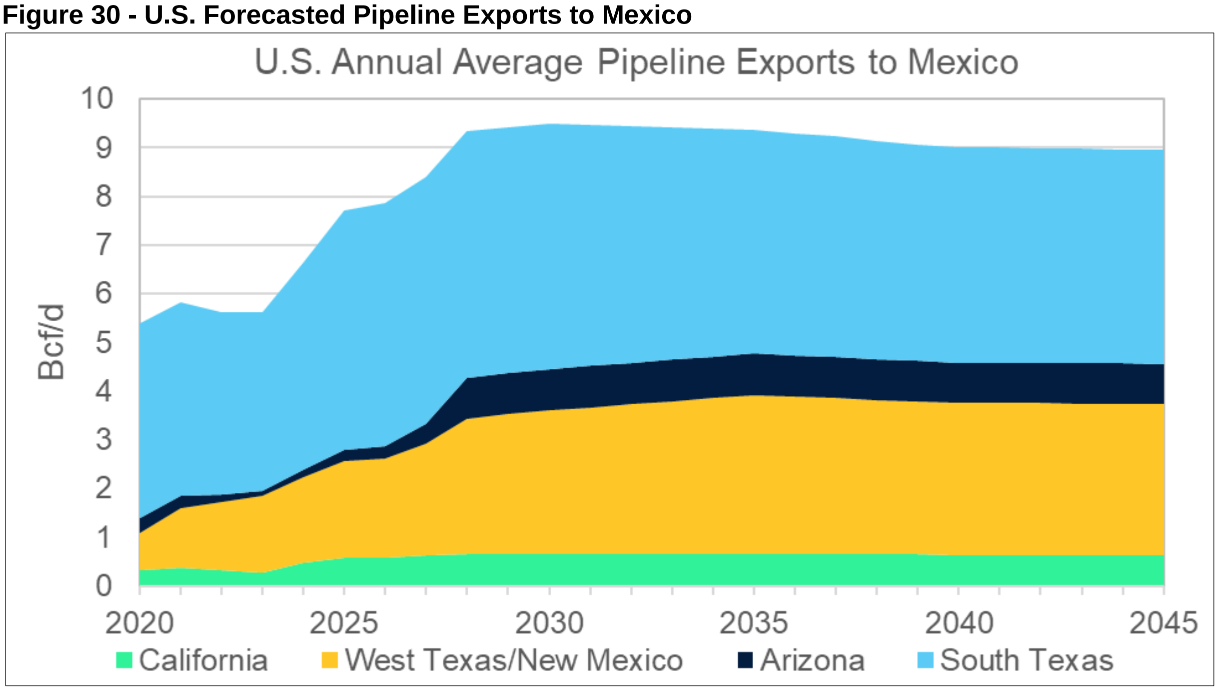
Figure 29 - U.S. Forecasted LNG Exports



Source: ICF Q3 2023 Base Case Gas Market Forecast (Does not include 10% of liquefaction fuel use at the terminals)

Pipeline exports to Mexico from the U.S. also experience growth in the ICF forecast, increasing from 5.6 Bcf/d in 2023 to 7.7 Bcf/d in 2025 and then peaking at 9.5 Bcf/d in 2030. This includes 1.9 Bcf/d of LNG export volumes re-exported from Mexico by 2029.

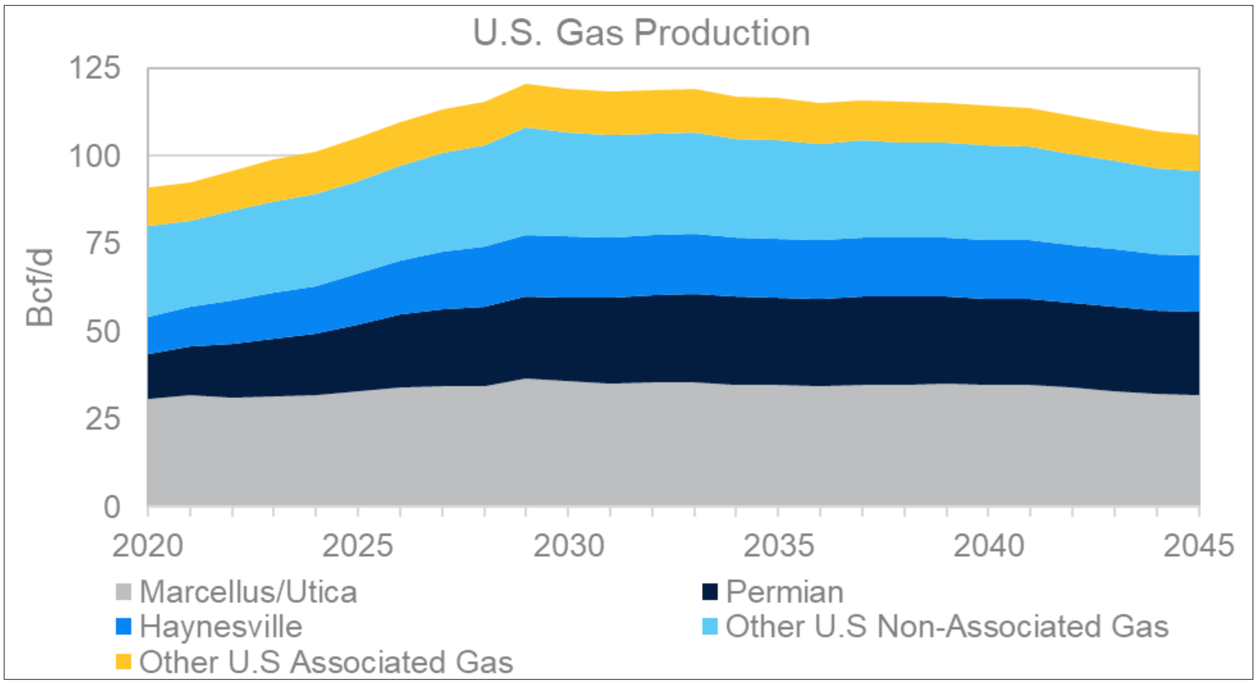
Figure 30 - U.S. Forecasted Pipeline Exports to Mexico



Source: ICF Q3 2023 Base Case Gas Market Forecast

On the supply side, the largest production increases are forecasted to come from the Marcellus, Utica, Permian, and Haynesville supply basins. Production from the Marcellus & Utica basins is forecasted to grow from 31.7 Bcf/d in 2023 to 36.5 Bcf/d in 2029 before it declines slowly for the rest of the forecast. Production in the Permian will grow from 16.3 Bcf/d in 2023 to 19.1 Bcf/d in 2025 and then 25.0 Bcf/d in 2033. In the Haynesville, production will grow from 13.2 Bcf/d in 2023 to 14.5 Bcf/d in 2025 and then to 17.4 Bcf/d by 2029. These supply increases will require additional interstate pipeline compression infrastructure to transport that supply out of the basins to market. There will also be more modest production growth in the Midcontinent, Bakken, and Rockies in the forecast.

Figure 31 - U.S. Forecasted Natural Gas Production



Source: ICF Q3 2023 Base Case Gas Market Forecast

The total size of the U.S. market for natural gas, which includes domestic demand and demand for net exports, is forecasted to grow from about 96.9 Bcf/d in 2023 to 118.5 Bcf/d in 2030 (22.4 % larger than it was in 2023). Even in 2045, however, the total market for domestic consumption and exports in the U.S. will remain at 105.5 Bcf/d, 8.9% larger than it was in 2023. Thus, even with projections of gas demand peaking in 2045, there will still be need for increased interstate compression capacity to and existing capacity to be in existence and used for at least the next two decades.

Appendix C: Gas Market Model

ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed by Energy and Environmental Analysis, Inc., now a wholly owned business unit within ICF, in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace.

The GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions;
- Measuring the impact of gas-fired power generation growth;
- Assessing the impact of low and high gas supply; and
- Assessing the impact of different regulatory environments.

In addition to its use for strategic planning studies, the model has been widely used by institutional clients and advisory councils, including the recent Interstate Natural Gas Association of America (INGAA) study. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

There are nine different components of ICF's model, as shown in Figure 32. The inputs for the model are provided through a "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure 33). Total U.S. and Canadian gas supplies include production, LNG imports, and storage withdrawals (in the withdrawal season only).[26] Gas production is solved in 81 distinct regions throughout the U.S. and Canada and is represented by both short- and long-run supply curves. In the short run (i.e., the current month), gas production is bound by the amount of available productive capacity. In the long run, productive capacity changes as a function of the available gas resource, the cost of development, and the solved gas price. North American LNG imports and exports are exogenously specified by the selected

[26] Storage withdrawals are solved within the model based on "storage supply curves" that reflect the level of withdrawals relative to gas prices. The curves have been fit to historical price and withdrawal data.

scenario. For each modeling, ICF includes its own projection of North American LNG imports and export by terminal.

Prices are also influenced by “pipeline discount” curves, which reflect the change in basis or the marginal value of gas transmission as a function of the load factor of the pipeline corridor. The structure of the transmission network is shown in Figure 34. The discount curves have been empirically fit to historical basis values and pipeline load factors on each pipeline corridor. Pipeline capacity expansions are exogenously specified for each scenario.

Figure 32 - GMM Structure

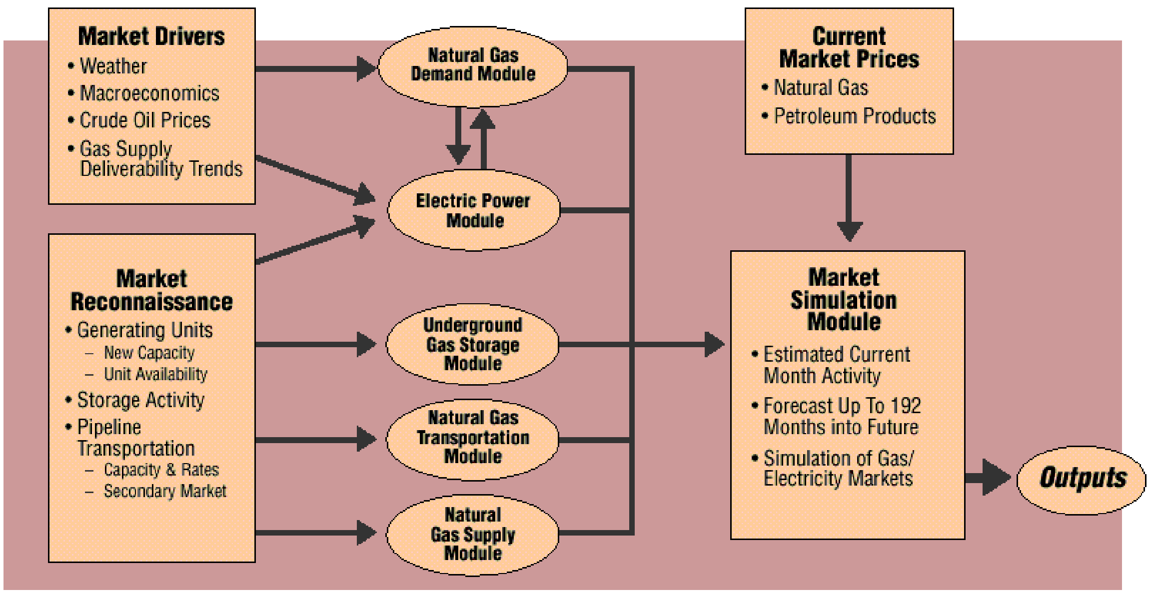
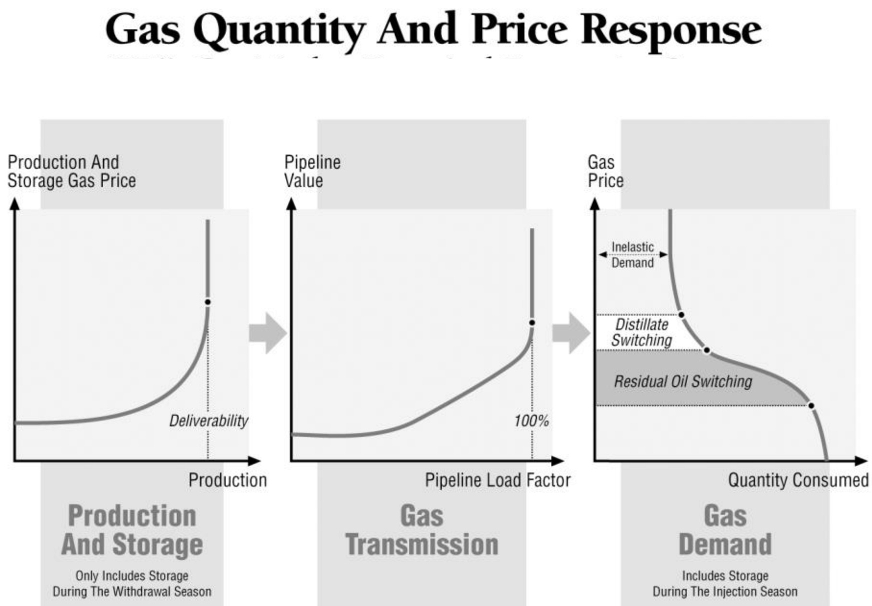


Figure 33 - Natural Gas Supply and Demand Curves in the GMM

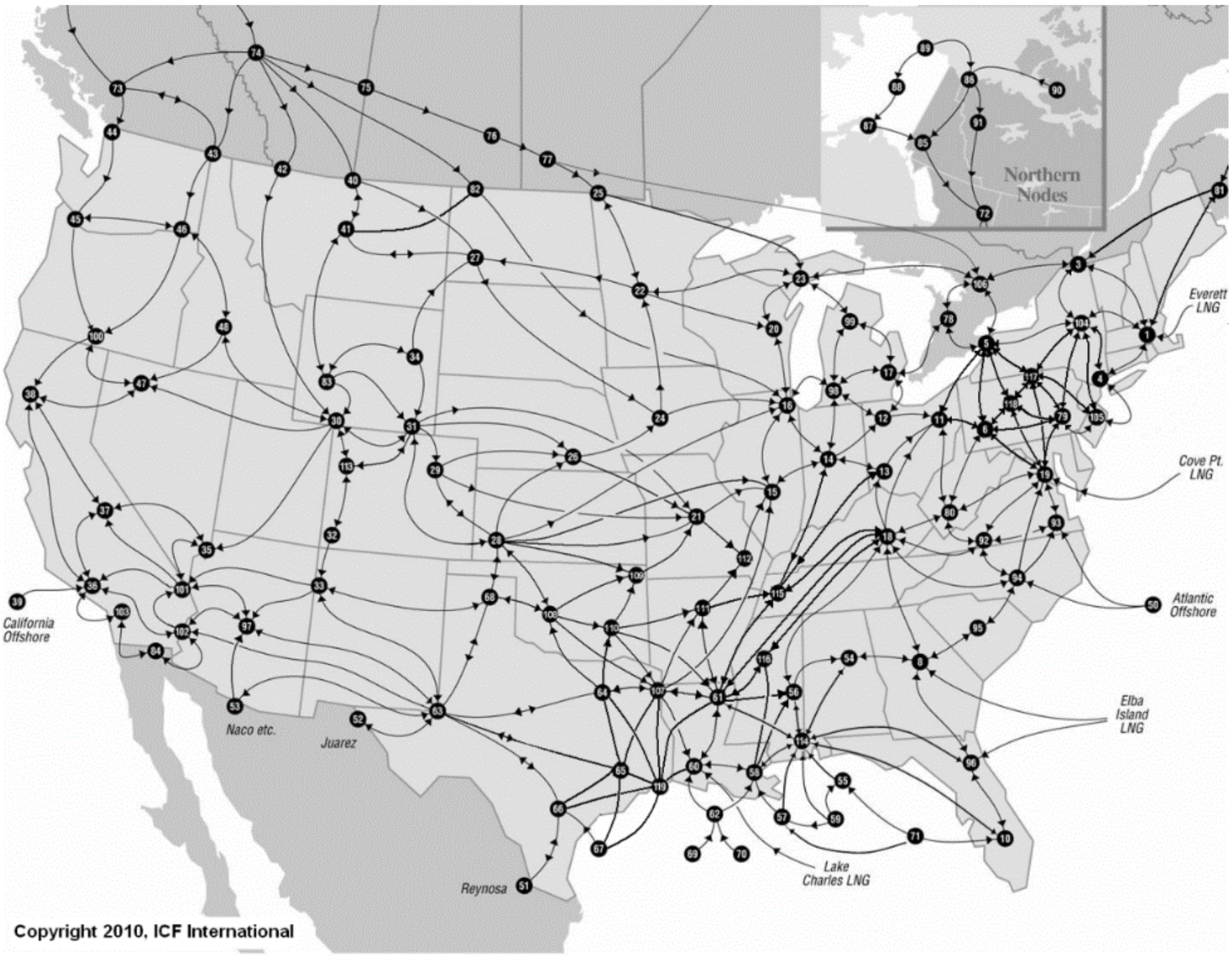


On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The gas demand routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The electric power module solves for the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The GMM forecast for power generation is consistent with ICF's Integrated Planning Model (IPM®), and the GMM power module allows for elasticity around IPM results to allow for seasonal/monthly variations. The GMM provides IPM with gas supply curves and basis that is used to determine gas prices for power plants within the IPM framework. The demand forecast for gas in the power sector from the IPM is then used as a benchmark to iterate both models until the gas prices and gas demand from power plants are converged in both models. Furthermore, IPM provides coal and oil retirements, and generation forecast from nuclear, hydro, and non-hydro renewables that is used in the GMM electric power model.

The GMM balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply, demand, and transportation curves. The model nodes are tied together by a series of network links in the gas transportation module. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and imports to Mexico) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and exports to Mexican) at each of the nodes and gas prices are solved for in the market simulation module.

Unlike other commercially available models for the gas industry, ICF does significant back casting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Figure 34 - GMM Transmission Network



Source: ICF

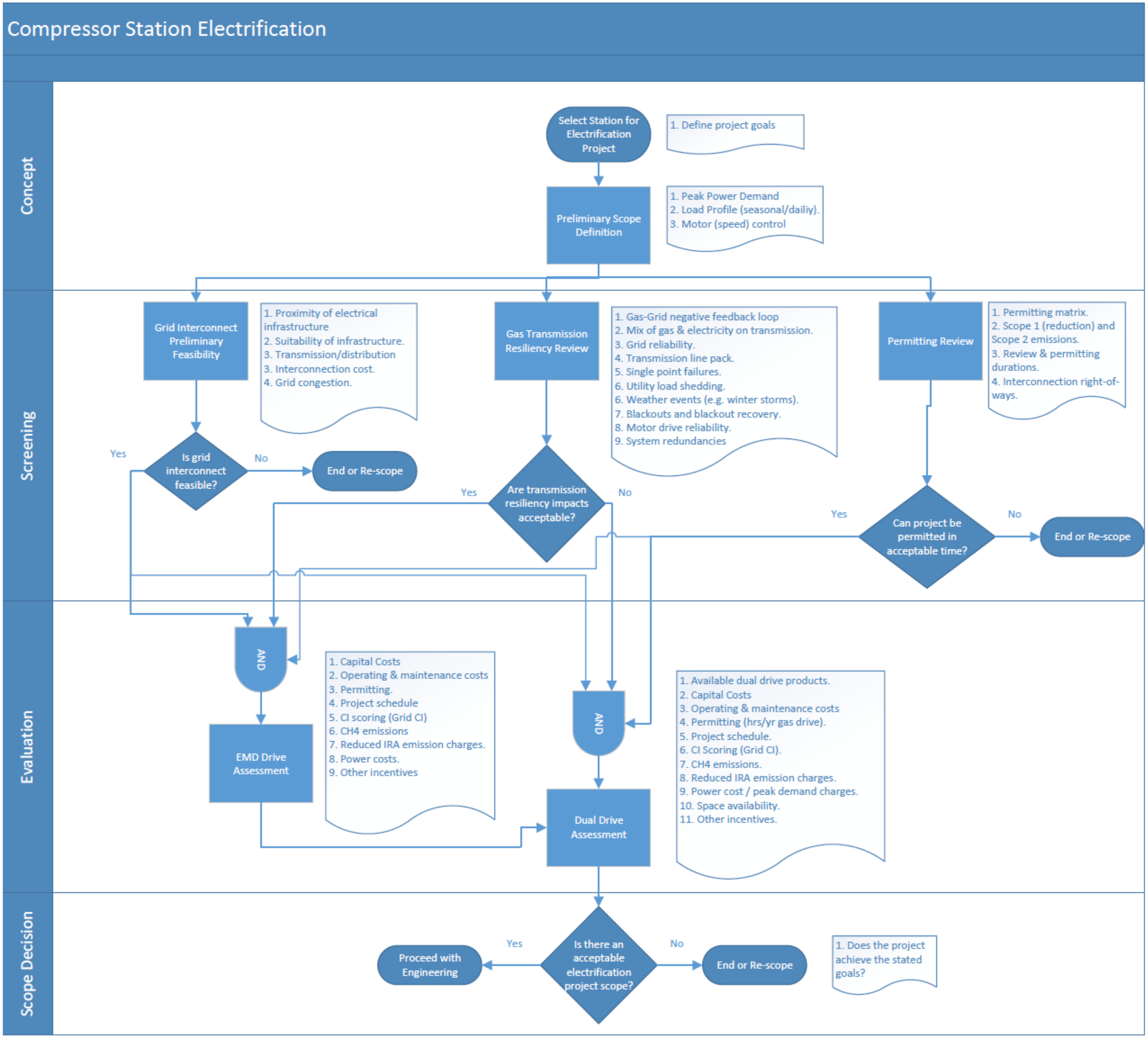
Appendix D: Data Sources for ICF's GMM Forecast

Describes Model Component		
Component of GMM Model	**Category**	**Source**
Market Drivers	Weather	NOAA for US; Government of Canada
Market Drivers	GDP	1. Quarterly historical U.S. GDP - BEA 2. Forecasted U.S. GDP for 1 year from WSJ survey of Economists 3. Forecasted Long-Term U.S. and Canadian GDP Growth - ICF Assumption (Currently 2.1% for U.S. and 2.0% for Canada) 4. Quarterly historical Canadian GDP - StatsCan
Market Drivers	Oil prices and Marker Price	EIA for historical RACC price; Futures and ICF view for long-term Coal - EIA for historical and IPM for forecast Expected RACC price - Same as RACC price Expected Gas Price at Henry Hub - same as Henry Hub for historical period and ICF view for forecast period Expected 7-year Bond Rate - 7% assumption
Demand	Residential	EIA for historical demand; ICF view for long-term
Demand	Commercial	EIA for historical demand; ICF view for long-term
Demand	Industrial	EIA for historical demand; ICF view for long-term
Demand	Power	EIA for historical demand; ICF view for long-term using the IPM Model
Demand	LNG Exports	ICF forecast of LNG export capacity buildout and utilization
Demand	Pipeline Exports to Mexico	EIA for historical pipeline exports to Mexico; ICF view for long-term
Supply	Supply	Historical from Argus, EIA; ICF view for long-term
Pipeline Transportation	Pipeline Network	Hitachi Energy; ICF view based on historical load factors and basis
Gas Storage	Storage	EIA for historical storage withdrawals; ICF view for long-term
LNG Imports	LNG Imports	Historical from EIA, ICF view for long-term

Appendix E: Corporate Electrification Framework

Step 1	Develop a corporate framework of priorities (power source, net zero targets, cost of capital, demand, age of existing asset, risks etc.) to evaluate near and long term emissions targets
Step 2	Analyze your **gas** transmission network by ISO region to identify key focus regions using scoring matrix
Step 3	Analyze key focus region to determine grid availability, congestion and routing of transmission lines
Step 4	Develop a downsized list of assets based on age, existing methane emissions and corporate policies need to be prioritized for electrification – consider assets that would reduce methane if replaced
Step 5	Review interconnection que study and determine grid availability to prioritize assets for electrification
Step 6	Develop a timeline for when projects need to begin development based on commercial considerations and transmission study
Step 7	Evaluate **appropriate replacement solution** – EMD vs Dual Drive for each **candidate** station
Step 8	Calculate methane reduction and carbon reduction for renewed assets / Develop proforma for selected assets
Step 9	Determine alternative partner opportunities to decarbonize – possible RNG injection, solar asset deployment for site functions etc.
Step 10	Develop economic analysis for proposed roadmap for electrification (by year). Qualify strategy by cost savings and methane reduction
Step 10	Share proposed plan with key decision stakeholders for feedback – develop workshops for solutions
Step 11	Begin roadmap activities and continue technical evaluation using decision matrix

Appendix F: Site Specific Electrification Decision Framework


Compressor Station Electrification
Concept
Screening
Evaluation
Scope Decision
Select Station for Electrification Project
1. Define project goals
Preliminary Scope Definition
1. Peak Power Demand
2. Load Profile (seasonal/dailiy).
3. Motor (speed) control
Grid Interconnect Preliminary Feasibility
1. Proximity of electrical infrastructure
2. Suitability of infrastructure.
3. Transmission/distribution
3. Interconnection cost.
4. Grid congestion.
Gas Transmission Resiliency Review
1. Gas-Grid negative feedback loop
2. Mix of gas & electricity on transmission.
3. Grid reliability.
4. Transmission line pack.
5. Single point failures.
6. Utility load shedding.
6. Weather events (e.g. winter storms).
7. Blackouts and blackout recovery.
8. Motor drive reliability.
9. System redundancies
Permitting Review
1. Permitting matrix.
2. Scope 1 (reduction) and Scope 2 emissions.
3. Review & permitting durations.
4. Interconnection right-of-ways.
Yes
Is grid interconnect feasible?
No
End or Re-scope
Yes
Are transmission resiliency impacts acceptable?
No
Yes
Can project be permitted in acceptable time?
No
End or Re-scope
AND
1. Capital Costs
2. Operating & maintenance costs
3. Permitting.
4. Project schedule
5. CI scoring (Grid CI)
6. CH4 emissions
7. Reduced IRA emission charges.
8. Power costs.
9. Other incentives
EMD Drive Assessment
AND
1. Available dual drive products.
2. Capital Costs
3. Operating & maintenance costs
4. Permitting (hrs/yr gas drive).
5. Project schedule.
6. CI Scoring (Grid CI).
7. CH4 emissions.
8. Reduced IRA emission charges.
9. Power cost / peak demand charges.
10. Space availability.
11. Other incentives.
Dual Drive Assessment
Proceed with Engineering
Yes
Is there an acceptable electrification project scope?
No
End or Re-scope
1. Does the project achieve the stated goals?