Interstate Natural Gas Pipeline Efficiency

Interstate Natural Gas Association of America
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TABLE OF CONTENTS

FIGURES AND TABLES

APPENDICES

EXECUTIVE SUMMARY

The North American natural gas transportation system is a complex network of interstate and intrastate pipelines designed to transport natural gas from producing regions to end-use markets. As of 2008, the United States and Canadian pipeline network consisted of approximately 38,000 miles of gathering pipeline and over 300,000 miles of transportation pipeline, of which interstate pipelines composed 217,000 miles.[1] In 2007, United States interstate pipelines transported 36 Trillion cubic feet (Tcf) of natural gas on behalf of customers.[2] Total United States storage capacity is 8.6 Tcf.[3]

Transporting natural gas via pipeline is an effective and efficient means of delivering energy over long distances, connecting production sources to local utilities, industrial plants and natural gas–fired electric power plants. Viewed in equivalent energy terms and equivalent transport distances, natural gas pipelines consume an average of two to three percent of throughput to overcome frictional losses compared to electric transmission lines, which lose six to seven percent of the energy they carry due to electric resistance.[4]

This report documents efficiency advances in the natural gas transportation pipeline industry since the advent of long mileage pipelines in the 1920s. This report also describes the factors that contribute to overall pipeline system efficiency and pipeline company decision-making with respect to efficiency improvements. In addition, this report reviews regulatory and environmental policies as well as competitive market pressures that affect a pipeline company's ability to maximize the efficient use of its system.

The "efficiency" of interstate natural gas pipelines can be viewed from two main perspectives: economic efficiency and transportation efficiency. Economic efficiency measures the delivered cost to customers compared to the cost of the natural gas, taking into account both

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[1] Energy Information Administration, *About U.S. Natural Gas Pipelines*, available at http://www.eia.doe.gov.
[2] *Id.*
[3] Energy Information Administration, *Monthly Underground Natural Gas Storage Capacity*, available at http:///www.eia.doe.gov.
[4] Energy Information Administration, *Frequently Asked Questions* (national-level losses were 6.5 percent of total electricity disposition in 2007), available at http://tonto.eia.doe.gov/ask/electricity_faqs.asp#electric_rates2.

fuel cost and transportation rates. The overall system transportation efficiency is a measure of the fuel and/or electric energy used to transport natural gas and is a function of the overall system design (the hydraulic efficiency), how the system is operated, and the efficiency of individual components (such as the compressor units).

Economic efficiency sometimes limits a pipeline company's ability to improve transportation efficiency. This occurs when the end-use market will not tolerate the price increase necessary to recover the cost of a measure that would improve transportation efficiency.

Pipeline companies strive to be as efficient as possible, yet must balance efficiency with the need to provide reliable and flexible service to customers. For example, pipeline companies often guarantee a sufficiently high delivery pressure so that local distribution company customers do not need to install additional compression behind their city gates. While this may reduce the transportation efficiency of the interstate pipeline, it increases the overall efficiency of the wellhead-to-burnertip value chain. Also, the increasing use of natural gas to generate electricity, both as a back-up to intermittent sources of renewable power and as a cleaner alternative to coal-generated power, means that pipelines do not operate as efficiently as they could if demand were constant and predictable. This reduced efficiency, however, is more than offset by the overall environmental and public health benefits gained by the increased use of natural gas to power generation. The interstate natural gas pipeline industry provides a flexible transportation service that accommodates wide variations in the demand for delivery of natural gas to a diverse market of end-use consumers, and thereby enhances the efficiency of the entire United States energy value chain.

It is important to recognize the impact of natural gas wellhead decontrol and pipeline restructuring. Both were about competition and choice, and interstate pipelines are the conduit for physically delivering the benefits of competition and choice to customers. A network of competitive, open access pipelines makes the overall market more efficient, providing natural gas sellers with access to multiple markets and natural gas consumers, with supply options previously unattainable.

The competitive market for natural gas transportation services also affects decisions by natural gas pipeline companies about investing in pipeline system efficiency improvements. Before investing, pipeline companies want assurance that the capital expenditures will reduce the cost to operate the pipeline, increase business for the pipeline company, or are needed to provide safe and reliable service.

Key conclusions of the report are as follows:

1. Each pipeline system is the unique result of its age, geographic location, original design, subsequent modifications, and shifting supply/demand patterns. As a result, technologies that may improve efficiency or may be cost effective on one pipeline system may not be feasible or economic on another pipeline system. A "one-size-fits-all" approach to transportation efficiency targets or technology prescriptions, such as mandatory efficiency targets or forced adoption of specific technologies, therefore is not practical.

2. Throughout its history, the interstate pipeline industry has invested in advances in pipeline, compressor and prime mover technologies that have contributed to continuous gains in the overall transportation efficiency of the natural gas pipeline network. Because pipeline companies have exploited the major economic technological efficiency improvements in the industry to date, there are limited opportunities for significant near-term efficiency gains.

3. The greatest opportunity for maximizing either economic or transportation efficiency is in the initial design and construction phase of a major facility. Maximum design efficiency is achieved by selecting the optimum balance of pipeline diameter, operating pressure and compression facility components for a specified flow rate. Once the pipeline has been built based on initial demand assumptions, it generally is not cost effective to change original design elements (such as maximum operating pressure) significantly to meet changed demand. While new energy saving technologies can be retrofitted on operating pipelines, the efficiency savings must generate sufficient revenue to balance the upfront capital costs, and operation and maintenance costs over the life of the retrofit projects.

4. Design efficiency and operating efficiency are not the same and should not be confused. Pipelines typically are designed for optimal transportation efficiency at peak flows, but frequently operate at lower flow rates, which may result in lower fuel consumed per unit of throughput. For that reason, fuel savings predictions for certain

technologies based on peak flow design conditions may not be realizable or economic under actual operating conditions.

5. The pipeline industry considers several key issues in evaluating whether to invest in an efficiency improvement. These include:

    - Whether newer equipment can be integrated with the existing equipment and the extent of the anticipated efficiency improvement;
    - Whether the improvement will impact reliability and the ability to meet contract demand;
    - The upfront capital cost and projected operation and maintenance costs of running the equipment;
    - Fuel savings or other cost savings;
    - The facility run time and percent load of the compressor unit, since how often and how hard the compressor runs affects the potential efficiency gain and potential fuel savings of the investment; and
    - The willingness of customers and the marketplace to pay rates that fund the investment.

6. While natural gas pipeline companies and supporting industries continue to invest in research and development on efficiency technology, the competitive commercial environment created by the restructuring of wholesale natural gas markets has affected the economic incentives for incorporating innovations to improve the transportation efficiency of the natural gas pipeline system:

    - Because of service options now available, customers often are committing to firm transportation contracts with much shorter terms than in the past. As a result, pipeline companies face substantial risk for recovery of capital investments in long-term efficiency improvements;
    - Pipeline-on-pipeline competition has given many pipeline customers substantial bargaining power. In conjunction with the Federal Energy Regulatory Commission's (FERC's) incremental pricing policy (under which new customers

must pay the cost of facilities built primarily to serve them), customers have an incentive to pay only for efficiency expenditures that will benefit them directly; and

- Pipeline companies have an incentive to make efficiency investments to the extent they can recover their investment by retaining cost savings over a reasonable time period. Yet, when the cost of innovations exceeds what customers are willing to pay under their transportation contract with their pipeline company, there is little incentive for pipelines to assume the risk association with such investments.

7. Increasingly stringent environmental regulations also affect pipeline companies' ability to maximize both economic and transportation efficiency by influencing equipment choices and siting. If the pipeline is in an area with strict emissions limits, it may be foreclosed from employing what would otherwise be the most efficient equipment choices. For example, the pipeline company may have to install electric-powered compression instead of gas-powered compression (even if gas would be more efficient), or relocate compression to a less than optimal area outside of the non-attainment area, or even install larger diameter pipeline in lieu of additional compression (which may require additional right-of-ways and will be much costlier than compression). These choices actually may push the pipeline company to purchasing decisions that reduce either economic and/or transportation efficiency.

8. Uncertainty over the timing and content of pending and proposed climate change legislation and regulation deters investment in efficiency improvements aimed at reducing greenhouse gas (GHG) emissions. The concern is that investment today to achieve improvements in efficiency could be rendered obsolete if final climate change legislation or regulation compels a pipeline company to modify or improve its system in a different way. Further, should the Environmental Protection Agency (EPA) be prescriptive in what it considers Best Available Control Technology (BACT) for regulating GHGs under the Clean Air Act, BACT compliance may limit pipelines' options to improve efficiency when they install a new compressor or modify an existing one.

9. The pipeline industry enhances the efficiency of the overall energy grid by providing flexible and reliable service in response to customer demand and market conditions. That responsiveness may come at a cost. For example, interstate natural gas pipelines serve gas-fired power generators, which are probably the most reliable and cost-effective back-up source of power for intermittent energy sources such as wind and solar. But to serve that load, interstate pipelines must stand ready to ramp up quickly, operating their compressor units in off-design conditions that lower the transportation efficiency of their systems. Nevertheless, from a broader perspective, this pipeline operational flexibility inures to the benefit of the power industry and the Nation's energy needs.

BACKGROUND

A. HOW PIPELINES WORK

Natural gas is an odorless transparent gas, primarily composed of methane. The most economical and efficient way to transport natural gas is via pipeline under pressure.[5] Gas compressors are used to pack the gas molecules, reducing their volume and increasing the energy density of the fluid. Compressor stations, typically sited every 50 to 100 miles, keep the natural gas flowing by boosting the pressure of the gas to compensate for pressure losses along the pipeline. As with all flowing fluids (liquid or gas), friction causes pressure to drop as the compressed gas moves through the pipeline. The pressure losses and corresponding decrease in transportation efficiency are related to many factors such as pipeline diameter, operating pressure, throughput, and internal roughness of the pipeline. Other transportation efficiency losses occur at compressor stations in the compression process. Additional background on how to measure efficiency is provided in Appendix A.

The industry employs two types of compressors – reciprocating and centrifugal. Reciprocating compressors are positive displacement devices, i.e., devices that add pressure by compressing the gas through mechanical displacement, typically with a cylinder-piston combination (like a bicycle pump). Centrifugal compressors use impellers to translate rotational velocities into higher potential energy in the form of pressure, which compresses the natural gas molecules (similar to a fan or hair dryer).

Compressors are driven by prime movers (reciprocating engines, gas turbines or electric motors). Reciprocating compressors are driven typically by natural gas-powered reciprocating engines (similar to automobile engines with a piston and crankshaft) or electric motors. Centrifugal compressors are driven by gas turbines or electric motors. Because the demand for natural gas is not constant on an annual basis, most pipeline compressors do not run year round or consistently at full capacity. Properly maintained compressors and pipelines can function well for many decades and there are many examples of 30 to 50 year-old equipment still operating today.

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[5] Vehicular/rail transport of compressed natural gas is not economically feasible because it is significantly less dense than a liquid (e.g., oil) or a solid (e.g., coal).

Storage facilities along the pipeline are another key component of a natural gas pipeline system. Pipelines use the same compression process and driver/compressor technologies to move gas in and out of pressurized geologic storage reservoirs. These facilities promote efficiency by enabling a pipeline company and its customers to maintain an inventory of natural gas along the pipeline for later withdrawal to meet peak demand.

B. PIPELINE SYSTEM EFFICIENCY

The "efficiency" of interstate natural gas pipelines can be viewed from two main perspectives: economic efficiency and transportation efficiency.

- Economic efficiency relies on providing the lowest delivered cost to customers, taking into account both fuel and transportation rates. Economic efficiency usually is measured in terms of cost per unit of throughput (i.e., dollars per thousand cubic feet or $/Mcf).

- Transportation efficiency is a function of the overall system design, the efficiency of individual components, and how the system is operated. Transportation efficiency is measured in terms of fuel or electric power burned per unit of throughput (i.e., British thermal unit (Btu) or KW/Mcf). Within this general definition of transportation efficiency, there are three other pertinent measures.

    - Hydraulic efficiency: As applied to pipelines, hydraulic efficiency is a measure of the loss of energy (pressure drop) caused by the friction of the flowing gas in the pipeline facilities.

    - Thermal efficiency: As applied to a prime mover (engine, turbine or motor) that drives a compressor, thermal efficiency measures how much of the potential energy of an input fuel or electric power is converted into useful energy that can be used to drive a compressor. The majority of energy that is not converted into useful energy is considered "waste heat" in the exhaust (such as noise), cooling and lubrication systems. The waste heat may be captured when economically feasible.[6]

[6] *See generally, Waste Heat Recovery Opportunities for Interstate Natural Gas Pipelines*, Prepared for INGAA by Bruce Hedman of ICF. February, 2008, and *Status of Waste Heat to Power Projects on Natural Gas Pipelines,* Prepared for INGAA by Bruce Hedman of ICF. November, 2009. For the

- Compressor efficiency: As applied to gas compressors, compressor efficiency measures how much energy is expended in compressing the gas compared to how much overall energy is used by the compressor. Inefficient compressors heat the gas instead of raising its pressure and thus have lower efficiency values.

The compressor unit efficiency (a product of the thermal and compressor efficiencies) and the pipeline hydraulic efficiency between compressor stations are variables that affect the overall system transportation efficiency. When designing its system, a pipeline company tries to optimize hydraulic efficiency through pipeline routing, pipeline diameter and operating pressure selections, and tries to optimize thermal efficiency and compressor efficiency through its compressor unit selections (including the engines, turbines, or electric motors that power the compressors).

Figure 1 below illustrates the linkage between economic efficiency and transportation efficiency.

purpose of this report, INGAA will not address waste heat recovery. Please see the above referenced white papers for a full discussion of waste heat to power on interstate pipelines.

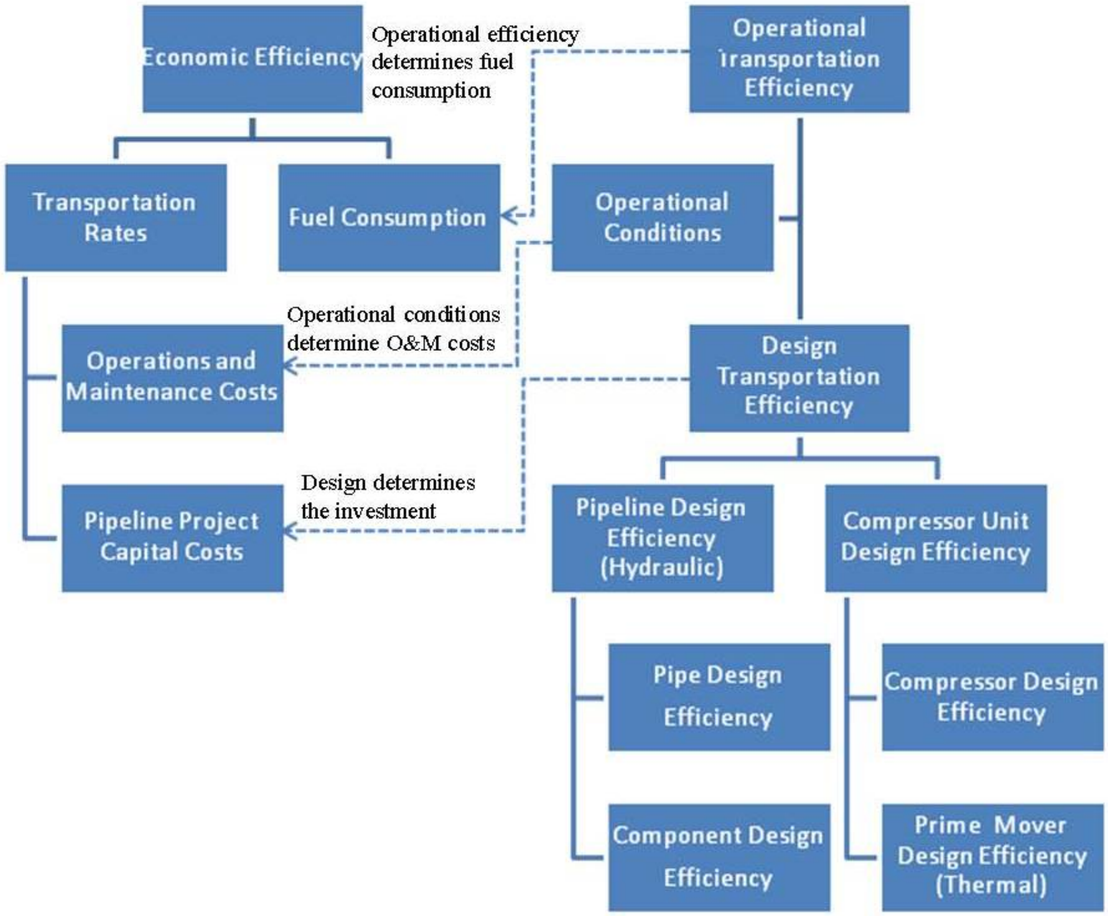

Figure 1. Linkage Between Economic and Transportation Efficiency

Design transportation efficiency (anticipated performance at a specific operating condition) is a combination of two separate components, the hydraulic efficiency of the pipeline and the efficiency of the compressor units at design conditions. The design hydraulic efficiency of the pipeline is based on the flowing frictional losses of the pipeline (diameter, pressure, roughness) and components (such as valves, regulators, and measurement devices) that the gas flows through. The compressor unit's design efficiency is a product of the design efficiency of the compressor (reciprocating or centrifugal) and the prime mover (reciprocating engine, gas turbine, or electric motor). A pipeline does not operate at design conditions for most of the year. The pipeline company operates its pipeline to meet its customers' contractual commitments. Variations in throughput due to changes in market demand and shifting supply sources, which affect how the system is utilized, and limitations on operating pressure determine the operational transportation efficiency of the pipeline system over time (how efficiently the pipeline operates compared to design conditions).

The economic efficiency of a particular pipeline is also a result of the pipeline system design and how the pipeline system is operated. The choice of pipeline diameter, components and compressor units determine the original invested cost of the pipeline. Those capital costs are combined with the predicted operation and maintenance costs of those particular design choices to establish gas transportation rates. In addition to transportation rates, the predicted use of pipeline compression (and the amount of fuel used and charged to customers) determines the design economic efficiency of a new project. Yet, since the pipeline often does not operate at design conditions, fuel usage may vary from predicted levels. Thus, operational economic efficiency often differs from design economic efficiency.

Basic economics may limit a pipeline company's ability to maximize the pipeline's overall transportation efficiency, such as when an efficiency improvement, particularly one with limited efficiency gains, cannot be cost justified or the cost recovery period is too long or too uncertain. Other competing parameters that influence pipeline decision-making on efficiency improvement projects may include future expansions, environmental restrictions, limitations on maximum allowable operating pressure (MAOP), siting concerns that may require rerouting the pipeline, and regulatory policies that encourage competition and expose the pipeline company to cost recovery risk. Federal regulatory policies have created a market for natural gas transportation that gives customers more bargaining power for lower cost service and shorter transportation contracts. At the same time, competition among pipelines serving the same market has created a natural incentive for pipeline companies to reduce costs and invest in higher efficiency technologies that can provide a competitive advantage.

A. MAJOR PIPELINE EFFICIENCY DEVELOPMENTS OVER THE YEARS

The modern day natural gas transportation system is a complex network of interstate and intrastate pipelines designed to transport natural gas from producing regions to end-use markets (see Figure 2). This network is the culmination of decades of design and construction, and includes 30 to 50 year old legacy engines,[7] older compressors with modern retrofit improvements, and new, state-of-the-art gas compressor systems. As of 2008, the United States and Canadian network consisted of approximately 38,000 miles of gathering pipeline and over 300,000 miles of transportation pipeline, 217,000 miles of which are operated by interstate pipelines.[8] Total capacity of the interstate natural gas pipeline grid in 2008 was approximately 183 Billion cubic feet per day (Bcf/d), which served to meet a major portion of the total United States and Canadian energy demand.[9] In 2007, United States interstate pipelines transported 36 Tcf of natural gas on behalf of customers.[10] In addition, total United States storage capacity is 8.6 Tcf.[11]

[7] Legacy engines used in the natural gas industry were relatively large, robust, slow speed (300 rpm) machines designed to operate continuously for years without a shutdown. Their use declined over time as the price of steel and construction costs escalated.
[8] Energy Information Administration, *supra* note 1.
[9] *Id.*
[10] *Id.*
[11] Energy Information Administration, *supra* note 3. The aggregate peak capacity for U.S. underground natural gas storage is estimated to be 3,889 Bcf.
http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/ngpeakstorage/ngpeakstorage.pdf

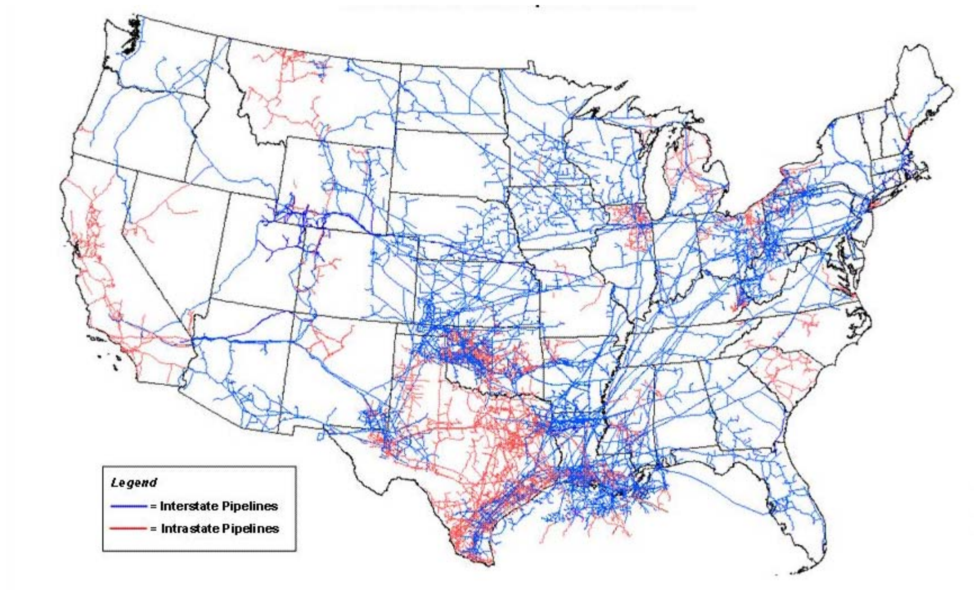

Figure 2. U.S. Natural Gas Pipeline Network

Natural gas pipeline technology has improved since 1929, when Peoples Gas Light & Coke Company completed the first long-haul pipeline, the Natural Gas Pipeline of America (NGPL). After World War II, the North American natural gas transportation system expanded substantially due to advances in metallurgy, steel pipe, welding techniques and compressor technology.

Since the 1950s, the general consensus on pipeline design was to design and build a pipeline using the combination of pipeline diameter and compression that would transport gas for the lowest delivered cost. Pipeline diameter is the biggest single variable in pipeline hydraulic efficiency. Advances in pipeline technology since the first long-haul pipeline have enabled pipelines companies to increase pipeline diameter and thus improve hydraulic efficiency. By increasing pipeline diameter and operating pressure, pipelines have been able to install less compression for the same throughput. Nonetheless, in determining the balance of pipeline and compression, the cost of the line pipe (the steel) was and remains a significant, if not the most significant, cost in pipeline construction.

In the 1950s, the dominant pipeline and compressor technology was the combination of largest available pipeline diameter (30-inch) with slow-speed integral reciprocating compressor units, i.e., units with the compressor integrated into the engine design. Rather than using a separate engine coupled through a crankshaft to a separate compressor, these "legacy" integral units directly incorporated reciprocating engines with reciprocating gas compressor cylinders. This allowed for smaller, more compact compressor units that could be installed at a lower cost. See Figure 3 below.

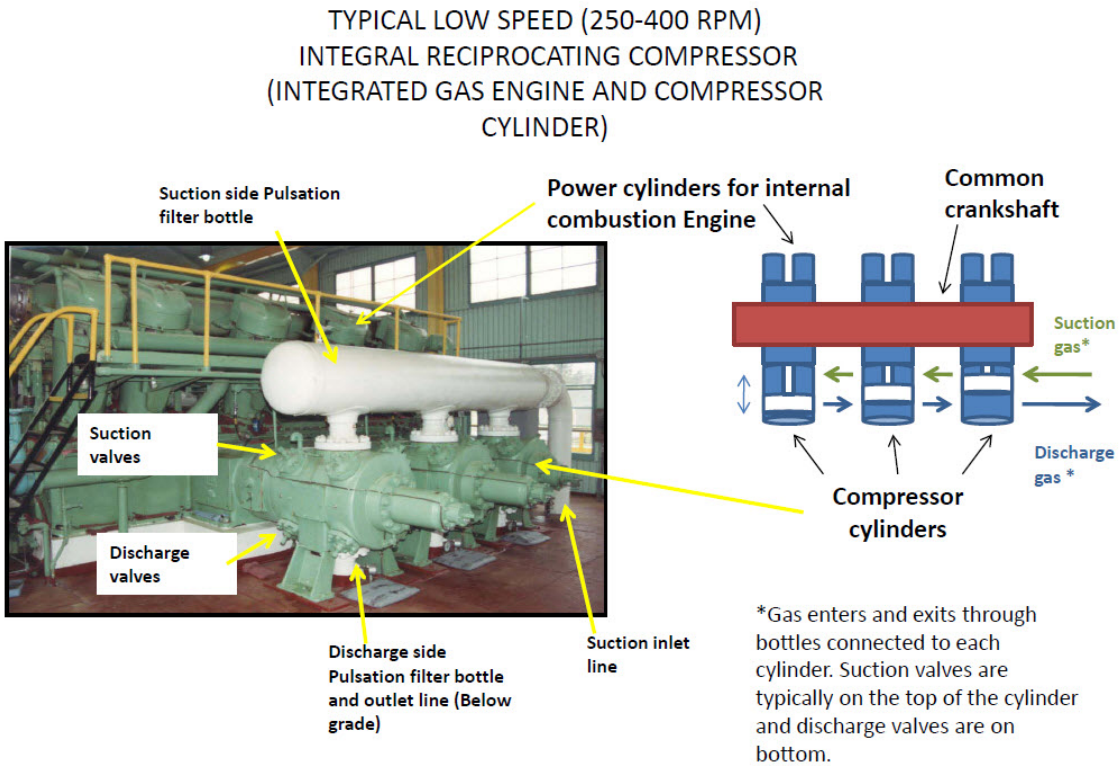

Figure 3. Integral Reciprocating Compressor

Beginning in the 1960s, improved metallurgy and manufacturing practices permitted the construction of larger diameter pipeline with higher strength steel to transport natural gas longer distances at higher operating pressures with less compression and at lower costs. Pipeline companies began experimenting with new, higher cost, internal coating technology that reduced friction, allowing pipelines to move gas even longer distances with even less compression, thus improving hydraulic efficiency between compressor stations. Since most areas were served by only one pipeline during the 1960s, and since the pipeline company provided a bundled sales and transportation service to customers, the pipeline company controlled when, how, and where gas would enter and move on its system. The pipeline company also would pack the line to maximize the system's operational flexibility by compressing gas above the intended delivery pressure in anticipation of customer demand. This practice still is utilized today to optimize compression efficiency to meet anticipated high demand periods. Pipeline companies often met fast-growing residential and commercial demand through additional mainline compressor stations that could offer the operating flexibility necessary to respond to new customers.

During the 1960s and 1970s, pipeline companies began to install centrifugal compressors driven by gas turbines. See Figure 4 below. Compared to integral reciprocating compressor units predominant in the 1950s, these centrifugal compressor units could be installed and maintained at a lower cost. Moreover, a pipeline company could purchase large centrifugal compressor units instead of multiple reciprocating compressor units at significant cost savings. During this period, integral reciprocating compressor technology stagnated and many suppliers ceased manufacturing large integral reciprocating compressors.

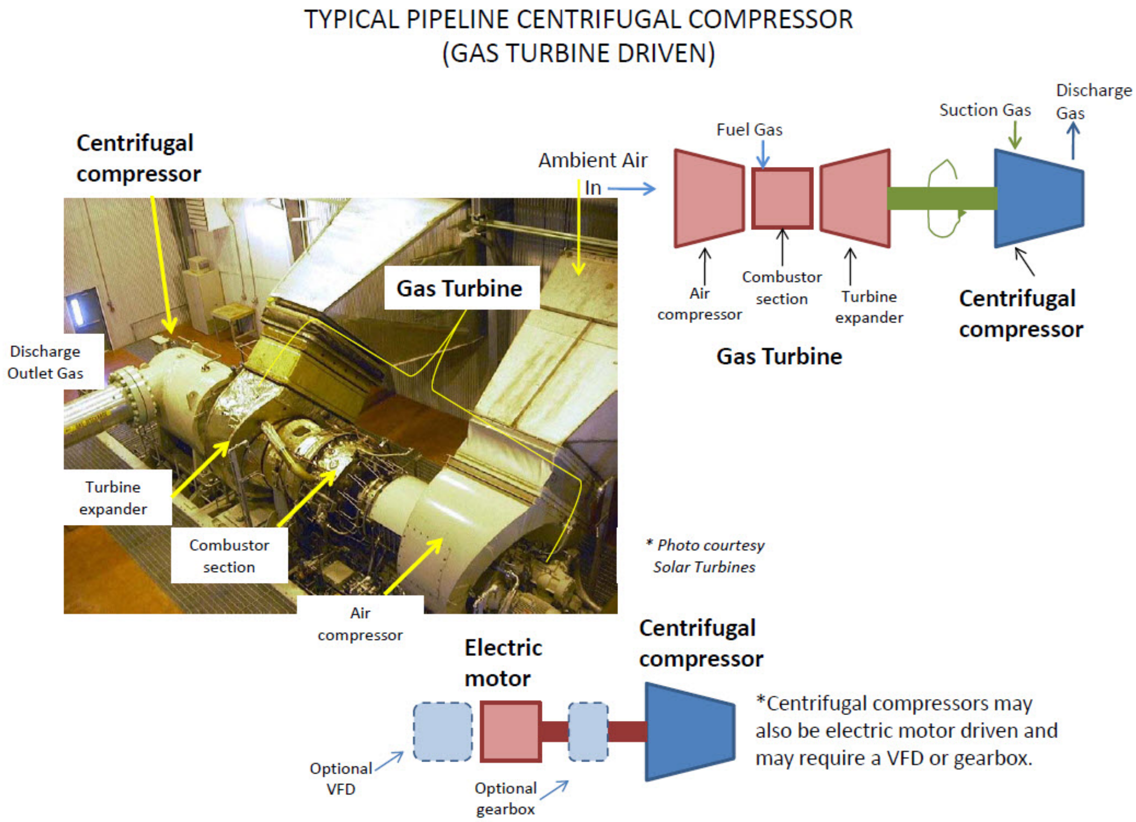

Figure 4. Gas Turbine Driven Centrifugal Compressor

In the 1970s, utilization of underground storage reservoirs located near market and supply areas permitted seasonal storage of gas, enhancing pipeline companies' ability to match supply and demand. Also, the pipeline industry adopted computer technology that permitted remote operation of facilities from a central gas control center. These and other computer-based technology advances improved the pipeline companies' ability to diagnose maintenance issues, and facilitated the later implementation of air emissions control technology and electronic timing controls.

Beginning in the 1980s, pipeline companies expanded the use of advanced pigging technology to clean and streamline the pipeline wall to reduce friction. In addition, modular construction of some newer gas turbine compressor units allowed pipeline companies to replace and overhaul separate modules. This reduced the downtime of high usage equipment and minimized the loss of operating transportation efficiency. Also, low emissions technology became commercially available, permitting the production of more efficient turbines without the increase in NO_x normally associated with higher firing temperatures.

Electric motors were not commonly used with larger, reciprocating compressors until technology enabled high horsepower, high voltage, variable speed, motor-driven systems. Although this technology emerged in the 1980s (and was implemented by some operators as early as 1982), modern large horsepower synchronous and induction electric motors and variable frequency drive (VFD) systems became more widely used in the late 1990s.

Reciprocating compressor units made a resurgence in the 1990s for low flow applications with the introduction of a new class of high speed reciprocating compressor units made possible by advances in technology and reductions in cost. High speed reciprocating engines (specifically, internal combustion engines), which offered higher thermal efficiencies and improved fuel economy than their low speed predecessors, were developed to match these compressors. See Figure 5.

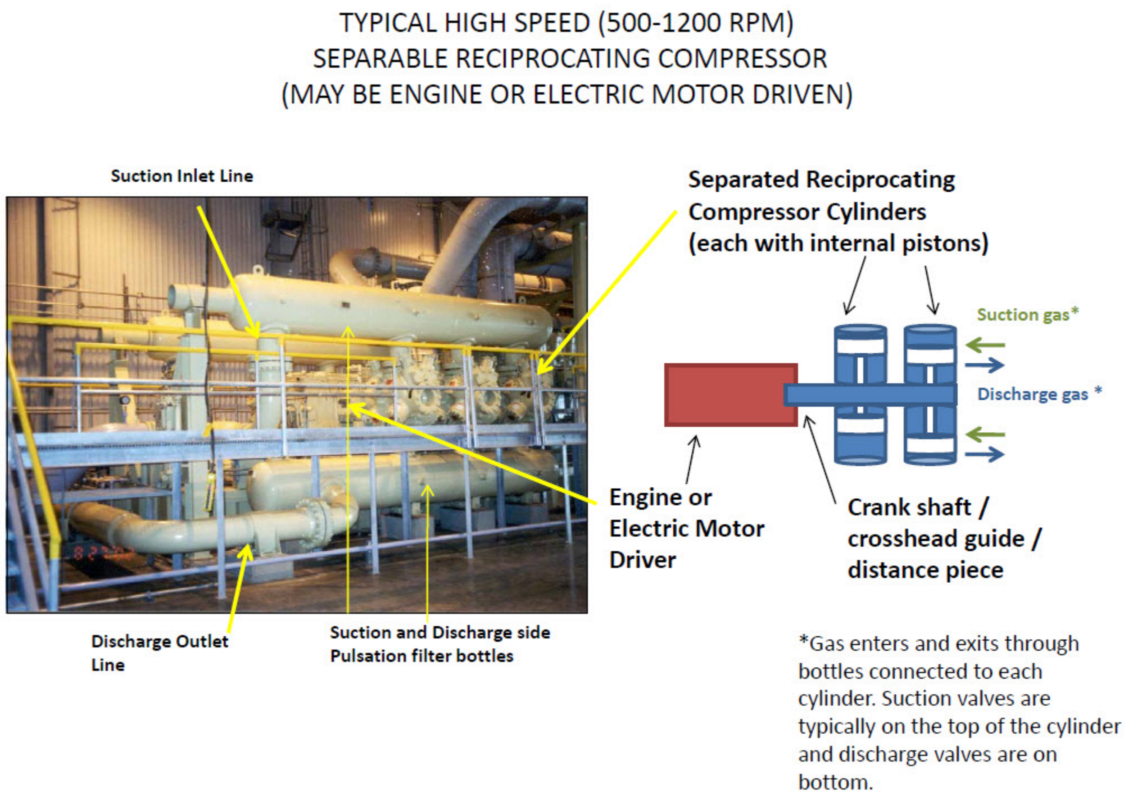

Figure 5. High Speed Separable Reciprocating Compressor

Nonetheless, when these high speed engines were combined with high speed reciprocating compressors (which had a lower efficiency than low speed reciprocating compressors), the overall net compressor unit efficiency actually was lower than vintage (low speed engine/low speed compressor) reciprocating compressor units.

In addition, technology advances allowed automation and communications systems to operate pipeline facilities remotely from a central gas control center, thereby reducing pipelines' operation and maintenance (O&M) costs. This advanced technology has allowed pipeline companies to communicate with compressor stations more quickly and to respond to changes in system flow more effectively.

Appendix B provides greater detail on compressor technology. Table B-1 compares and contrasts the design efficiencies and attributes of the compressor units in service today.

B. SUMMARY OF HISTORICAL EFFICIENCY DEVELOPMENTS

Over time, pipeline companies have incorporated various technological advances that have permitted significant gains in pipeline hydraulic efficiency, prime mover thermal efficiency and compressor efficiency, as well as improvements in flow control, reliability and emissions control. Pipeline companies have tried to balance installing the most efficient equipment with the willingness of customers to pay for the state-of-the-art technology. This challenge has been complicated by the continuous expansion of the pipeline system to meet a growing customer base. The result is a myriad of pipeline technologies (diameter, steel strength, and operating pressure) and compressor station technologies (compressors, prime movers, and piping connected to the compressor units), all of different vintages, distributed throughout today's pipeline network.

As shown in the following table, pipeline companies have used increasingly larger diameter pipeline and higher pressures to improve the hydraulic efficiency of the system. Since 1940, maximum line pipe diameters of newly built pipelines have doubled from 24 inches to 48 inches, while the MAOP has more than doubled from 720 psig (pounds per square inch, gauge pressure) to 1750 psig or higher. This has been achieved through the development of economic, high strength steels, enabling pipelines to be built economically and safely operated at higher pressure/stress levels. Advances in high strength steel continue to this day. Improved quality control in the manufacturing, transportation, installation and testing of new pipe has allowed the operating pressure of some new pipe installations to increase from 72 percent to 80 percent of its specified maximum yield strength (SMYS).

Table 1: Changing Pipeline Design and Construction Parameters

Decade of Construction	Available Maximum Diameter	Available Maximum Operating Pressure	Available Pipeline Steel Yield Strength (psi)	Available Maximum Stress Levels (% of SMYS)	Available Internal Coating	Piggable Pipelines
<1940	24”	720 psig	42,000	72%	No	No
40-49	28”	720 psig	46,000	72%	No	No
50-59	30”	860 psig	52,000	72%	No	No
60-69	36”	860 psig	60,000	72%	No	No
70-79	36”	1020 psig	65,000	72%	No	No
80-89	42”	1440 psig	70,000	72%	Yes	Yes
90-99	42”	1440 psig	80,000	72%	Yes	Yes
00-09	48”	1600 psig	100,000	72%	Yes	Yes
Present	48”	1750 psig	100,000	80%, 72%	Yes	Yes

Fuel rates for the newest generation of very large gas turbines (>20,000 hp) have improved 32.5 percent, from 9426 Btu/hp-hr to 6362 Btu/hp-hr (an increase in thermal efficiency improvement from 27 percent to 40 percent). Smaller units have improved as well as demonstrated in Solar Turbine’s Gas Turbine Efficiency Improvements chart below, Figure 6.

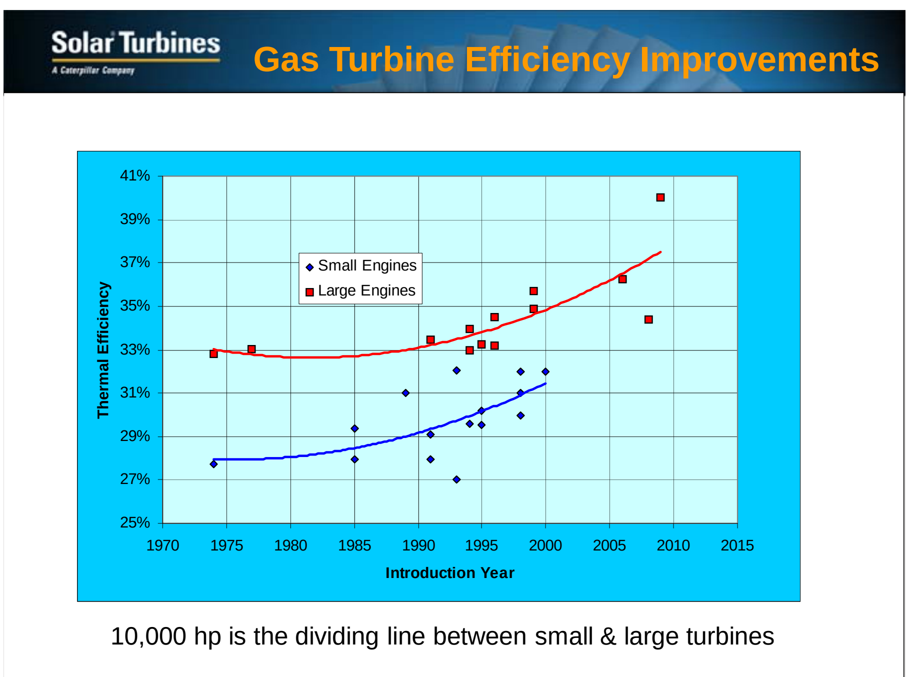

Figure 6. Gas Turbine Efficiency Improvements

Solar Turbine Titan 250 Gas Turbine; Gas Electric Partnership, February 2010

The efficiency of the newest generation of centrifugal compressors, powered by these gas turbines, has increased from 75 percent to 88 percent. As a result of these advances, the overall design efficiency of a gas turbine-driven centrifugal compressor unit now is close to 33 percent, which is a 50 percent improvement over the machines deployed 20 years ago. Advances in centrifugal compressor efficiency have been aided by computational fluid dynamic analysis, intensive testing, and the use of impellers with three-dimensional geometry to assist in aerodynamic flow passage design.

In addition, there have been advances in reciprocating engine technology. Since 1995, the efficiency of newer and most sophisticated gas-fired reciprocating engines has increased by four percent (from 42 to 46 percent peak thermal efficiency at 100 percent load) while at the same time the effectiveness of emissions control systems has improved to meet increasingly stringent NO_x requirements. Higher speed reciprocating compressors have provided a means of compressing more gas and thereby achieving higher throughput at a lower installed cost. Many pipeline companies now are designing systems in which modern electric motors (90 to 95 percent thermal efficiency at the site),[12] or reciprocating engines (30 to 43 percent thermal efficiency) are used to power high horsepower, low speed, reciprocating compressors (80 to 92 percent compressor efficiency) to improve overall compressor unit efficiency.

One more development affecting efficiency has been the surge in construction of natural gas storage. Because it generally is more economical in providing short-term delivery or receipt capacity than expanding pipeline capacity, storage has become an increasingly important way for pipeline companies to meet customers' peak day capacity requirements and to accommodate outages. By using storage to augment baseload pipeline capacity and help to moderate rapidly varying demand requirements, pipelines can be operated more efficiently. Producers, suppliers and customers use storage to balance short-term demand swings during the day and other changes during periods that do not correspond to the traditional heating season pattern.

[12] When source energy losses are considered, electric motors may achieve 25 to 46 percent thermal efficiency.

C. LEGISLATIVE AND REGULATORY DEVELOPMENTS AFFECTING EFFICIENCY

Along with advances in pipeline and compression technology, legislative and regulatory initiatives also have affected the incentives for improving efficiency in the interstate natural gas transportation industry. The wellhead natural gas decontrol enacted by the Congress in 1978 and 1989 created a competitive natural gas commodity market that led to the emergence of large supply and market hubs. Unbundling of pipeline companies' natural gas sales and transportation services, implemented by the FERC through Order 436, *et al.*,[13] further contributed to a competitive interstate natural gas transportation system. These developments made customers less dependent on a single pipeline company for their entire gas supply, and enabled them to satisfy their need for gas supply without contracting for transportation capacity all the way back to the wellhead.

The FERC's pro-competitive policies also have affected how pipeline companies invest in equipment or processes that may increase transportation efficiency. In the past, local distribution companies and other large pipeline customers committed to long-term contracts (15 to 20 years), making it feasible to design and build in long-term transportation efficiency investments under rates that afforded the pipeline company a reasonable opportunity to recover its investment plus an adequate rate of return on the investment. Today, by contrast, pipeline customers are less apt to commit to long-term contracts on existing systems. Further, as a result of pipeline-on-pipeline competition, many pipelines have to discount heavily to attract and retain long-term customers. Pipeline companies face cost recovery risks, even on new Greenfield projects, after the initial contract terms expire. Moreover, large customers have the market power to force pipeline companies to compete on the basis of price to build new or expanded pipeline capacity to meet new demand. In that price-competitive context, the feasibility of discretionary system-wide transportation efficiency improvements is dependent on the willingness and ability of customers to commit to rate levels that will fund the improvements

[13] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, Regs. Preambles 1982-85, FERC Stats. & Regs. ¶ 30,665 (1985), *order on reh'g*, Order No. 436-A, Regs. Preambles 1982-85, FERC Stats. & Regs. ¶ 30,675 (1985), *order on reh'g*; Order No. 436-B, Regs. Preambles 1986-90, FERC Stats. & Regs. ¶ 30,688, *order on reh'g*, Order No. 436-C, 34 FERC ¶ 61,404, *order on reh'g*, Order No. 436-D, 34 FERC ¶ 61,405, *order on reh'g*; Order No. 436-E, 34 FERC ¶ 61,403 (1986), *aff'd in part and vacated and remanded in part sub nom. Associated Gas Distribs. v. FERC*, 824 F.2d 981 (D.C. Cir. 1987).

over the long term, or the ability of the pipeline company to recover its investment costs through cost savings or increased throughput.

In addition, customers' increased use of capacity rights made available under FERC's Orders 636 and 637 *et al*.[14] may require pipeline companies to operate their systems differently, and less efficiently, than contemplated by the original system design. For example, meeting multiple demand requirements at different delivery points may require a pipeline to maintain higher pressures, alter flow rates or impose larger turndown requirements[15] on compressor stations, producing less efficient compressor operation than envisioned under the design conditions. In addition, a decline in baseload demand from industrial customers and a dramatic growth in the utilization of natural gas-powered electric power generators (typically dispatched to meet midrange and peaking electric loads) make the pipeline flow requirements highly variable compared to historically more constant demand loads. The electric generation load has, in some cases, created a summer demand peak requiring more fuel use. On many pipelines, steady baseload demand has been replaced by less predictable, day-to-day, load swings. Notwithstanding these new operational challenges, pipeline companies have adapted to wide variations in supply and demand patterns through off-design operations that often require, for example, more frequent starting and stopping of compressors with little notice. While such off-design operation results in higher fuel use, interstate gas pipelines can serve peaking electric generators by ramping up pipeline compressors quickly (either gas turbine, engine or motor-driven) and use line pack to meet rapidly changing load swings.

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[14] Specifically, customer rights related to flexible receipt and delivery points, segmentation of capacity to multiple points, and capacity release to both primary and alternate points. *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs., Regulations Preambles Jan. 1991 – June 1996 ¶ 30,939, *on reh'g*, Order No. 636-A, FERC Stats. & Regs., Regulations Preambles Jan. 1991 - June 1996 ¶ 30,950, *on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *on reh'g*, 62 FERC ¶ 61,007 (1993), *aff'd in part, vacated and remanded in part, United Dist. Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997); *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *aff'd in part and remanded in part sub nom. Interstate Natural Gas Ass'n of America v. FERC,* 285 F.3d 18 (D.C. Cir. 2002).

[15] Turndown refers to how flexible a compressor is at different operating conditions (flow and pressure). The greater the turndown capability of the compressor unit, the greater the flexibility the compressor unit has to operate under different flow and pressure conditions.

Federal, state and local environmental and siting regulations often affect the ability of a pipeline company to maximize design efficiency. Pipeline companies design their systems based on the optimal balance between pipeline and compression and the type of compressor unit that will best serve the project. Yet, these decisions often are impacted by environmental regulations that limit the emissions of air pollutants at compressor sites. As illustrated in Appendix B, Table B-1, different compressors and prime movers excel under different design scenarios and operating conditions. Yet, if the pipeline is in an area with strict emissions limits (such as a non-attainment area), which limits additional emissions greatly, the pipeline company may not be able to install a compressor driven by either a gas-powered reciprocating engine or a gas turbine, even if the gas-powered compressor would have been the most efficient solution under the circumstances. The pipeline company may need to relocate compression to a less than optimal area outside of the non-attainment area, install an electric motor to drive a compressor (which would have no emissions at the site), and/or install larger diameter pipeline in lieu of additional compression (which may require additional right-of-ways and will be much costlier than compression). These choices actually may push the pipeline company to purchasing decisions that reduce both economic and transportation efficiency. For example, suboptimal placement of a compressor unit may decrease transportation efficiency and drive up fuel costs. Further, installing an electric motor-driven compressor in a remote area far from the electric grid is an unattractive option, particularly due to the time and cost it would take to interconnect to the power grid and issues related to the reliability of the power supply.

Similarly, modifying, upgrading or retrofitting an existing pipeline compressor station may trigger the EPA's New Source Review (NSR). The NSR requires a pipeline company to apply for a permit in advance of modification and (1) to install BACT if the station is a "major source" in an attainment area or (2) to install controls to meet the Lowest Achievable Emission Rate in a non-attainment area. These control requirements often require the installation of add-on controls, which cause the compressor to run less efficiently. Further, as technology improves, EPA continues to require greater control technology and it is not always clear whether the pipeline's modification designs will meet EPA's control requirements without major changes to equipment. With such uncertainty, pipelines companies often are hesitant to modify compressors since the modification may trigger the NSR, which applies regardless of whether the station is in a non-attainment area.

EPA's proposed rule establishing national emissions standards for hazardous air pollutants (NESHAP) for reciprocating internal combustion engines (RICE) also illustrates how regulatory requirements may compromise pipeline efficiency. The proposed rule would limit the carbon monoxide and formaldehyde emissions from engines commonly used at natural gas compressor stations. The only way to assure compliance with the proposed limits would be to install post-combustion catalytic control equipment. This equipment degrades engine efficiency by requiring the engine to operate at a higher fuel-to-air ratio, causing the engine to burn more fuel than necessary and thus operate less efficiently. The efficiency degradation could be as much as one to two percent per unit which, measured over the entire system, could be quite significant.

Additionally, uncertainty over the timing and content of pending and proposed climate change legislation and regulation deters investment in efficiency improvements aimed at reducing GHG emissions. Pipelines are concerned that investments made today to achieve incremental improvements in efficiency could be rendered obsolete if final climate change legislation or regulation compels a pipeline company to make a wholesale change in compressor technology. Additionally, should the EPA be prescriptive in what it considers BACT for regulating GHGs under the Clean Air Act, BACT compliance may limit the efficiency improvement options available when a pipeline company installs a new compressor or modifies an existing one.

Further, the increased use of renewable energy sources may affect pipeline operations. Many industry analysts anticipate that natural gas-powered electric generators will be called upon to fill the gap created by the intermittent nature of solar and wind power and the current lack of commercialized methods to store electricity from these energy sources. This, in turn, could create new demand for natural gas transportation and storage services that can respond quickly and reliably in providing intermittent fuel for these gas-powered electric generators. Natural gas pipeline transportation offers tremendous flexibility and the capability to operate at off-design conditions enabling power companies to use gas-fired generation to meet their customers' load when intermittent supplies wane. While operating at off-design conditions to bring compressors on and off line quickly (to back up the intermittent renewable energy supply) likely increases fuel use, the interstate natural gas pipeline system's capability to operate so flexibly is a great advantage in meeting the Nation's diverse energy needs.

In summary, pipeline companies have been proactive in identifying and incorporating ways to improve pipeline system operating efficiencies while at the same time providing reliable service to an increasingly complex and variable customer base. Pipeline companies must weigh decisions to maximize transportation efficiency with competing considerations, such as the ability to meet customer contractual requirements and market demands, the ability to recover the cost of the investment, compliance with existing and pending environmental regulations and legislation, and landowner siting accommodations, that at times lessen or eliminate a pipeline company's ability to make such efficiency investments.

D. RESEARCH AND DEVELOPMENT

Pipeline companies are engaged in research and development (R&D) either themselves or through organizations such as the Gas Machinery Research Council (GMRC), Pipeline Research Council International (PRCI), Pipeline Simulation Interest Group (PSIG), Gas Technology Institute (GTI), Southwest Research Institute (SwRI) and the American Society of Mechanical Engineers (ASME). Through these organizations, pipeline companies can pool their resources and undertake R&D on a relatively economical basis.

Pipeline companies have long worked with original equipment manufacturers (OEMs) such as Cameron, Solar Turbines, General Electric, Dresser-Rand, Rolls-Royce, Ariel and Caterpillar who develop and deploy advances in thermal and compressor efficiency and thereby reduce engine fuel consumption, lower maintenance costs and downtime, and increase availability. Pipeline companies have installed prototype units to assist OEMs in testing and commercializing new products. For example, dry low emission (DLE) technology has been developed for gas turbines in order to reduce high NO_x production due to higher firing temperatures. DLE technology makes the compressor units much more complex and costly to buy, operate and maintain, so the improvement must be weighed against the associated cost. Nevertheless, due to R&D efforts focused on these technologies, modern gas turbines achieve significantly lower air emissions (e.g., NO_x, CO_2) than their predecessors.

Pipeline companies also have worked with material suppliers and contractors, such as steel mills, coating shops and welding companies, to advance pipeline and coating material technology and construction techniques. This partnership has produced high strength steels, new welding techniques, and internal and exterior coatings. Finally, new operations simulation software enables pipeline companies to predict and optimize the combination of compressor units that will consume the least fuel to transport a given quantity of gas to meet an anticipated market demand. Appendix E highlights a sample of research studies on various topics such as metering, turbine and engine retrofit technology, compressor technology, and corrosion and leak detection.

In the following sections, this report will examine the considerations related to economic and transportation efficiency in the design, operation and maintenance of natural gas pipelines. This historical review has shown that the current United States and Canadian pipeline network is composed of many technologies representing different eras of pipeline development. Each pipeline system is unique; each pipeline and each of its compressors and prime movers is a product of its design era, its origins, the additions made over time, and the market it serves. A "one-size-fits all" solution to implementing cost effective energy investment and efficiency improvement would not be practical.

DESIGNING PIPELINES FOR EFFICIENCY

Efficient pipeline design must consider many competing factors that influence economic and transportation efficiency. This section describes the major decisions confronted by pipeline planning engineers and the pipeline officers that ultimately must justify the capital investment regarding the selection of pipeline diameter and compression requirements, compressor unit components, and how the pipeline company weighs the competing demands of investing in the most efficient infrastructure with serving its customers at competitive rates.

A. PIPELINE SYSTEM DESIGN

The greatest opportunity for maximizing both the economic and transportation efficiencies of a pipeline system is in the initial design and construction phase of a major pipeline facility. Overall system transportation efficiency will be determined during the design phase by a combination of the expected hydraulic efficiency of the pipeline and the efficiency of the compressor station components. The initial design normally is based on peak day contractual commitments plus an accommodation for future demand that can be reliably forecast.

The pipeline company selects its components and equipment based on a balance of reliability and flexibility. Since an interstate pipeline is a long-lived asset, wholesale replacement of an existing pipeline system with new facilities is not economic. The choices made during the initial design significantly limit the ability of a pipeline company to enhance transportation efficiency later by replacing individual system components or by modifying the pipeline system. Consequently, subsequent modifications to accommodate shifting supply zones, changes in customer demand and technological improvements must be integrated into the existing system and must complement rather than replace the initial design.

B. PIPELINE VERSUS COMPRESSOR STATION DESIGN

During the initial system design, or during any system expansion or other major construction project, pipeline companies consider the optimum combination of pipeline diameter, operating pressure, and compression facilities needed for a given system flow rate necessary to meet projected contractual demand. From a capital perspective, the installation of compression typically is significantly less costly than the installation of long miles of pipeline. As a rule of thumb, in a new pipeline design, a pipeline company can spend two to four times more initial capital on pipeline than on compression to achieve the same delivered cost of gas. Still, in choosing compression over pipeline to achieve a given deliverability, a pipeline designer also is opting for typically higher operating and maintenance costs (along with associated labor) as well as increased fuel usage. These operating and maintenance costs increase as the equipment ages.

Pipeline system design engineers explicitly calculate the trade-off between the costs of a larger diameter pipeline (with less compression) versus the initial capital and life cycle[16] operating and maintenance costs of supplemental compression to achieve a desired flow rate. The analysis of a given investment to improve either hydraulic or thermal efficiency must measure the anticipated value of the cumulative fuel savings over the useful life of the investment. Pipeline companies also must factor in the future demand for the pipeline's service and the length of initial contracts in order to determine whether there will be a reasonable opportunity to recover investment costs.

To determine the optimum combination of pipeline diameter and horsepower (i.e., compression) requirements, pipeline project designers use "J Curves", which compare the delivered cost of fuel to the cost of pipe. In the J Curves shown in Figure 7, the pipeline company considered a range of pipeline diameters from 20-inch to 42-inch pipe and various MAOP values. While the 36-inch diameter pipeline would be preferable, the pipeline designer may select a larger diameter pipeline or choose to operate the pipeline at a higher pressure if future growth is reasonably predictable. Yet, naturally, the larger pipeline would be more expensive. Thus, the choice of pipeline diameter and operating pressure are based on an assumed flow rate and affect delivered cost.

Another factor that affects the balance between pipeline diameter and compression is the non-linear relationship between flow and fuel (due to flow losses – see Appendix A). As shown in Figure 8 (using actual data for the Tennessee Gas Pipeline System), doubling the flow from 700 to 1400 MMcf/d quadruples total fuel usage from 9 MMcf/d to 35 MMcf/d. The disproportionate increase in fuel consumption at higher flow rates does not mean that the

[16] Life cycle costing is the evaluation of an investment by considering the costs and benefits over its entire serviceable life.

compression operation becomes less efficient. The fuel consumption indicates that the pipeline is highly utilized and is required to transport more gas to meet demand.

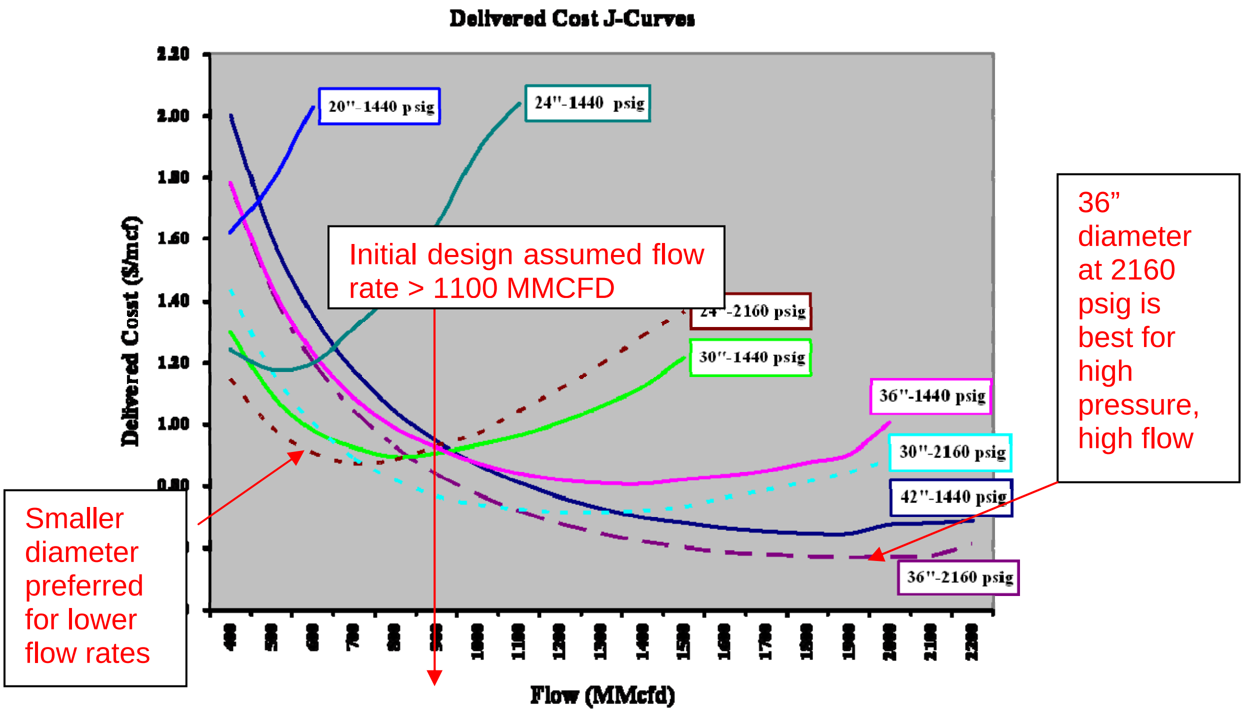

Figure 7. Example J Curves for Pipeline Delivered Cost

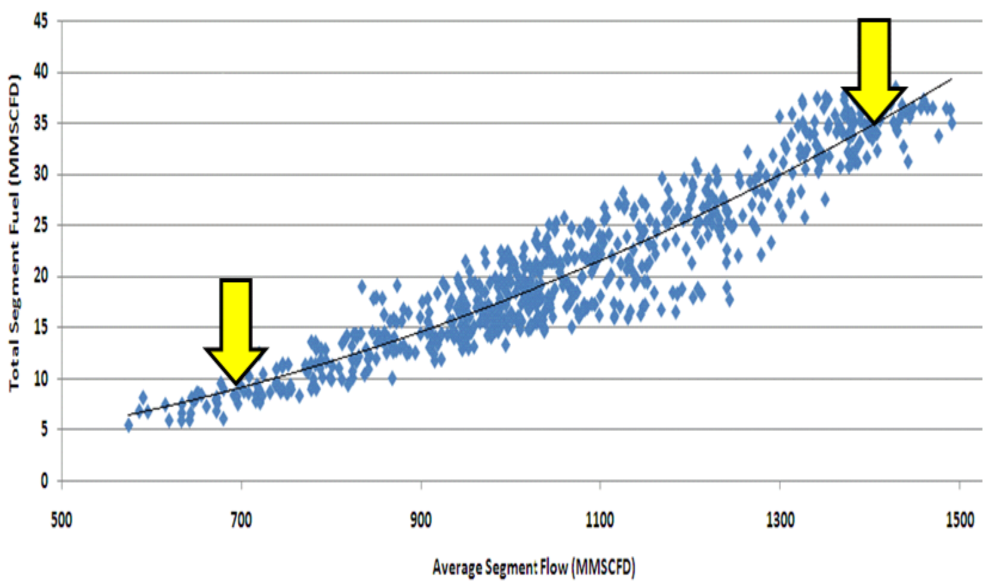

Figure 8. Exponential Fuel Consumption Resulting From Increased Flow
Tennessee Gas Pipeline; Gas Electric Partnership Presentation, February 2010

In addition to choosing pipeline diameter, a pipeline company designing a facility considers whether to install internally coated pipeline. The real benefit of internal coating occurs when the pipeline is experiencing high flow rates because it reduces friction in the pipeline, and, consequently, reduces the amount of horsepower needed to maintain pressure for a given throughput. Because it involves a substantial expense, internal coating is not effective in many circumstances. Assuming that rates support the investment, internally coated pipeline could be used for future expansions, pipeline replacements or as a trade-off to compressor horsepower. Further information on internal pipe coating is provided in Appendix C.

The location and spacing of compressor stations is another important factor in overall pipeline transportation efficiency. Appendix D illustrates how station location can be used to reduce cost while optimizing efficiency. Environmental and landowner considerations, however, may dictate compressor selection and spacing that is less than optimal from an engineering and efficiency perspective.

C. COMPRESSOR SELECTION

After a pipeline company determines the optimal balance between pipeline specifications and horsepower requirements, it selects the compressor units that best meet its load profile and operating needs. A number of considerations go into the selection including: (1) forecasted operating conditions, (2) the unit's air emissions to ensure compliance with air quality regulations, (3) the upfront, installed costs, (4) the projected operating costs, (5) the projected maintenance costs and availability of replacement parts, (6) the unit's compatibility with the existing compressor fleet, (7) the overall efficiency of the compressor unit (i.e., a combination of the thermal efficiency of the prime mover and the compression efficiency of the compressors themselves), (8) the reliability of compressor unit components, and (9) the expertise of pipeline personnel with particular equipment.

While pipelines are designed to operate at peak hydraulic efficiency under high load conditions, many pipelines operate at low load conditions for several months of the year. Pipeline designers therefore select compressor units that best allow a pipeline to meet peak day contractual commitments while achieving an acceptable efficiency level when operating off peak.

To illustrate the difficulty of maintaining high efficiency with wide variability requirements in flow and compression, Figure 9 depicts the seasonal load variability of a typical mainline pipeline system over a five year period from 2005 through 2009. Monthly average throughput varied significantly over this period. Throughput was close to 600,000 Dth/d during the winter months, yet dropped to roughly one third of this level in other months. The pipeline company can meet the flow requirements for eight months of the year by running minimal amounts of compression. Because additional horsepower is required only from November through March, the pipeline company may select compressor units with the lowest cost that provide the greatest flexibility. Compressor units with a flat efficiency curve over a broad range of operational points also may be suitable, but efficiency may not be as a great when operated outside of this range at peak flow. This example shows the difficulty in justifying an investment in the most fuel efficient prime mover and compressor package for a particularly high flow design point (which may be more costly as well), if the pipeline company anticipates that it will operate at this design flow for only a small portion of the year.

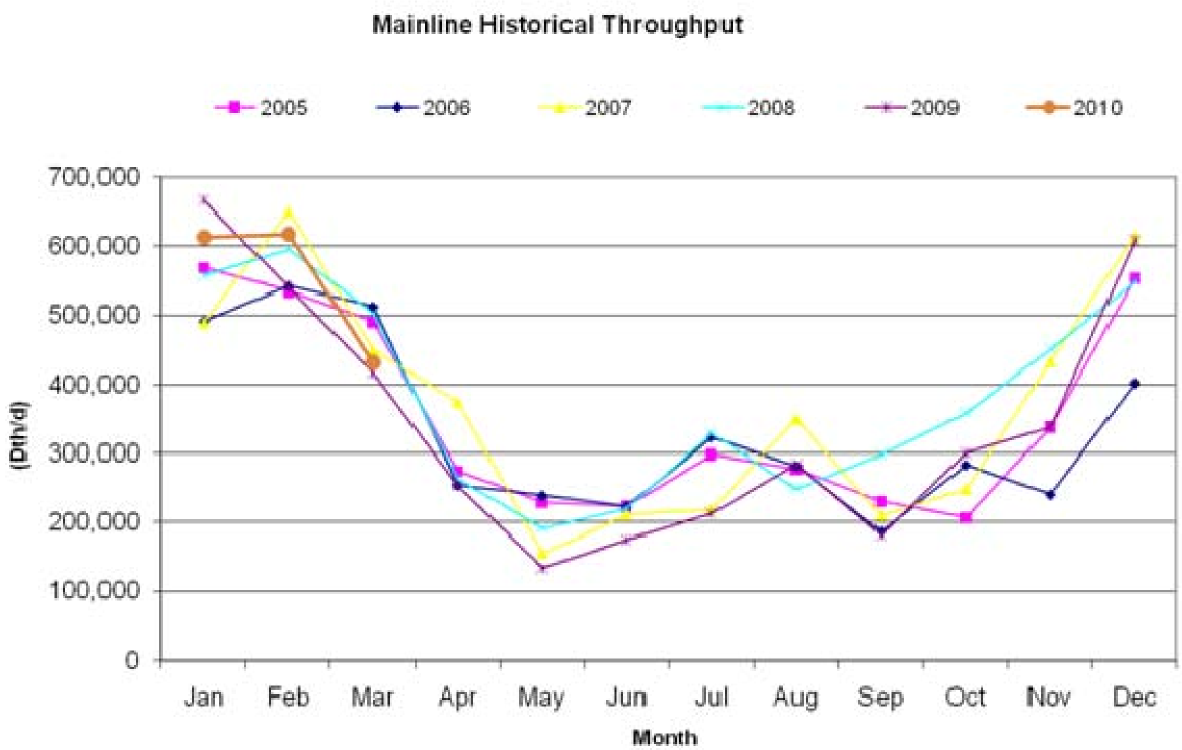

Figure 9. Five Year Daily Average Throughput (Dth/d) Variations by Month on U.S. Pipeline

Another design decision that can affect pipeline efficiency is whether to install one or more large units per compressor station versus several smaller units. To address variable market area customer demands while maintaining high operational efficiency, pipeline companies sometimes select multiple, smaller compressor units that can be switched on and off to meet throughput and pressure needs.

Assuming the same configuration and location, two smaller compressor units will have a higher cost per horsepower compared to a larger unit due to economies of scale. One fully-loaded, larger unit will be more fuel efficient and will cost less than two smaller equivalent sized units. By contrast, one fully-loaded, smaller unit will be more fuel efficient and offer more flexibility than one partially-loaded, larger unit. Similarly, operating multiple, smaller compressors can achieve better overall fuel efficiency than a single larger compressor if the pipeline operates predominately at less than maximum throughput. The fuel savings, however, may not outweigh the installation costs of additional smaller units.

To illustrate this point, one pipeline company recently considered adding additional compression at one of its stations. Figure 10, below, shows the vast range of operating conditions that occurred at the compressor station in question. The pipeline company had a choice. It either could install a single larger centrifugal compressor with a high design efficiency at full-flow conditions (86 percent) but with poor efficiency at less than ideal flow conditions (77 percent), or it could install multiple smaller units that are not as efficient as larger units under full-load conditions, but provide the operator greater flexibility to meet the demand variability of its customers. In this case, the pipeline company chose the latter. Even though the single, larger unit was less expensive and had a higher design efficiency than the combination of the smaller units, in actual operation, the smaller units will achieve higher fuel efficiency and offer greater flexibility based on the station’s operating conditions. Another pipeline company, with different load variability, may select a different compressor mix, either in the number of compressors or the type of compressor.

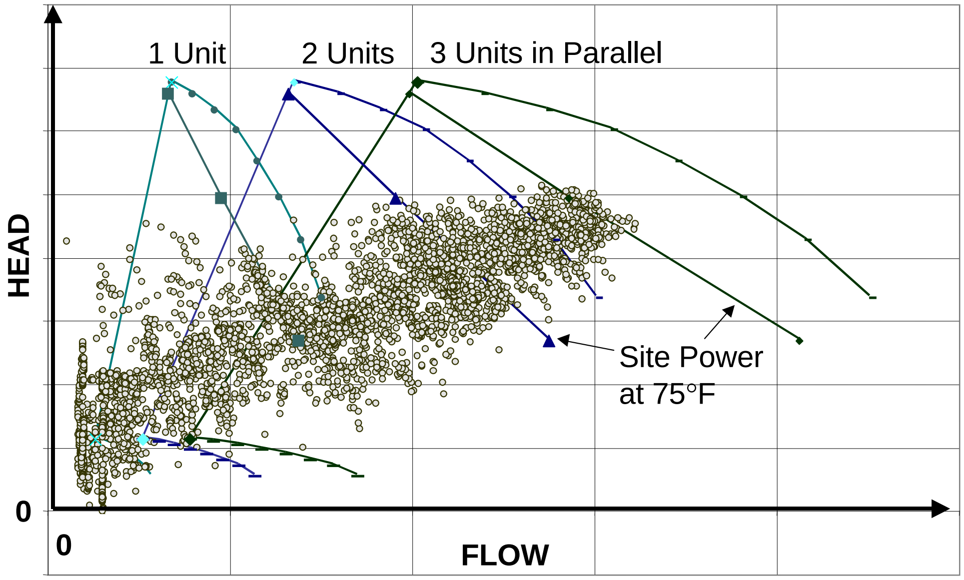

Figure 10. Depiction of the Scheduling of Multiple Compressor Units to Adjust for Actual Operating Conditions at a Pipeline Compressor Station

In addition to the number and size of compressors, pipeline companies also make choices when selecting types of compressors. There are inherent design tradeoffs between reciprocating compressors and centrifugal compressors, and the operating parameters and range of each technology vary greatly. In general, reciprocating compressors are more effective in situations with varying pressure ratios (i.e., where the ratio of discharge to suction varies substantially), while centrifugal compressors are more effective in situations with some flow variability and relatively constant pressure ratios. Therefore, for a pipeline with variable customer flow requirements, but fairly constant pressure conditions, a centrifugal compressor is the preferred technology. On the other hand, where a pipeline needs to respond to wide ranging pressure ratio conditions (given large changes in suction or discharge pressure or both), reciprocating compressors perform more efficiently than centrifugal compressors. Regardless of the type of compressor, when a pipeline operates outside the design parameters of the unit (either in terms of pressure ratio or flows), the compressor will use more fuel than it would have at design conditions because all compressors are less efficient when operating away from their optimum design conditions (either in terms of pressure ratio or flows). See Appendix B, Table B-1 for a comparison of advantages, disadvantages and efficiency ranges for each pipeline compressor technology.

D. PRIME MOVER SELECTION

Three primary types of prime movers (drivers) are used in pipeline applications: reciprocating gas engines, gas turbines and electric motors. The principal attributes and drawbacks of each are described below.

Reciprocating Gas Engines: Similar to an internal combustion engine used in a motor vehicle, the reciprocating gas engine uses a chamber, filled with natural gas, to drive a piston. The gas is ignited and combusted to cause the piston to move. Slow low speed and high speed engines are matched with compressors of corresponding speed. Legacy internal combustion, slow speed, engines have significantly less sophisticated controls and lower fuel efficiencies than state-of-the-art engines. While today's reciprocating engines are quite efficient, they do have power limitations and can have high vibration issues that affect reliability. Certain components may be high maintenance, and the engine units require ample spare parts and service contracts as back up.

Gas Turbines: Gas turbines rely on the hot exhaust gas produced from the discharge of a gas generator to drive a power turbine. The shaft output power from the power turbine is used to drive the pipeline gas compressor. Two types of turbine are used: (1) the aeroderivative engine, which is based on gas turbines developed for the aviation industry (the hot exhaust gas is used to push the aircraft through the air rather than through a power turbine) and (2) the industrial turbine which is designed specifically for industrial use. Aviation industry developments have contributed to the continual improvement in performance (in terms of power and efficiency) of both aeroderivative and industrial gas turbines.

Electric Motors: Electric motors are more reliable and more efficient as stand-alone pieces of equipment than either reciprocating engines or gas turbines. They are able to ramp up quicker than reciprocating engines or gas turbines. They also have an advantage where air quality regulations are an issue because they do not emit NO_x and CO_2 at the point of use. There are a number of competing factors, however, that affect the suitability of using an electric motor as the prime mover for a pipeline compressor. One is the requirement for variable speed and the resulting relatively high cost of an electric motor, variable frequency drive, auxiliary equipment, and the training and maintenance needed to support them. The availability and proximity of a suitable electric power supply or substation is also an issue, because it can be costly to install a new interconnecting electric power transmission line, and it may be difficult to obtain the necessary regulatory approvals. Reliability of the electric power transmission grid (overhead transmission lines are susceptible to damage in severe weather conditions), availability and cost of power from the local distribution company, and the obligation to pay electric demand charges even when the unit is not running are additional factors when considering installation of an electric motor. In addition, looking ahead to GHG regulations, the carbon footprint advantage that electric motors have over the reciprocating engines and gas turbines at the site is offset by high energy losses in the transmission of electric power and the higher carbon footprint of the electric generation power source (e.g., electricity from coal).

The pipeline company's compressor selection (centrifugal or reciprocating) usually dictates the choice of the prime mover (gas turbine, reciprocating engine, or electric motor). Natural gas-powered reciprocating engines generally are limited to driving reciprocating compressors. Natural gas-powered turbines generally are limited to driving centrifugal compressors. Electric motors may be used with either compressor technology, although pipeline companies have begun using electric motors to power centrifugal compressors on a more widespread basis than reciprocating compressors.

The upfront cost of component parts is an important consideration for pipelines when selecting compressors. Life cycle and avoided costs, where applicable, also are factors to be considered, however. Low speed compressor units powered by reciprocating engines are the most expensive option in terms of installation cost ($/hp). Gas-fired combustion turbines and electric motors have approximately the same installed cost.

E. COMPRESSOR UNIT SELECTION

Pipeline companies select the appropriate equipment for a particular service based on both technical (e.g., flow, pressure ratio, utilization, efficiency) and commercial considerations (e.g., delivered cost, contractual underpinning, etc). The weight given to these criteria varies from pipeline to pipeline or from application to application. What may improve system efficiency or be cost-effective on one pipeline system may not be cost-effective or practical on another system. Therefore, there is no one-size-fits-all efficiency prescription that will yield desired efficiency improvements on all pipeline systems.

The installed cost of a compressor unit may vary significantly depending upon whether it is a Greenfield installation (i.e., a brand new compressor station), an additional compressor unit installed at an existing station, or the replacement of an existing compressor unit with a state-of-the-art unit. Generally, an additional compressor at an existing station is the least expensive option, followed by a state-of-the-art replacement unit; a Greenfield unit is the most expensive option.

Based upon an actual case study, Table 2 below compares the upfront capital cost of various compressors and prime movers for a 14,400 horsepower compressor replacement project in 2010. Typically, installed costs for a mid-sized natural gas compressor powered by a combustion turbine at a Greenfield location is $2,500 to $3,500 per horsepower.

Table 2. Relative Driver / Compressor Cost Comparison for 14,400 Horsepower Compressor Station

	Estimate for Initial Cost on Site				
	Single GT Turbine / Centrifugal Compressor	Multiple GT Turbines / Centrifugal Compressors	Electric Motor / High Speed Reciprocating Compressor	High Speed Engine / Reciprocating Compressor	Slow Speed Engine / Reciprocating Compressor
Total Installed Cost	100%	129%	130%	132%	154%

In this particular case, the pipeline company elected to purchase a slow speed engine/ reciprocating compressor unit, even though it was the most expensive option, because of the potential fuel savings. However, when the price of gas dropped below $7/Dth, this project became less attractive. The project was canceled when gas prices dropped below $4.50/Dth and the load factor of the pipeline dropped approximately 50 percent. The pipeline company is looking for other locations to install the slow speed engines and to allocate the dollars spent.

As illustrated above, initial cost is not the only criterion for selecting a compressor unit. A pipeline company may select a more expensive unit rather than select a lower cost compressor unit for a variety of reasons. For example, a pipeline company may select a more expensive unit if it anticipates that the lower cost unit will operate frequently outside of its optimum operating range and will not provide the operating flexibility the pipeline requires. Also, a pipeline company may select a more expensive unit if the unit provides greater reliability or will be more fuel efficient. In addition, a pipeline company may select a more expensive unit rather than having to install additional equipment to reduce emissions on a lower cost unit, which would increase the overall cost. Furthermore, a pipeline company may be driven to select a more expensive, variable speed, electric motor-driven compressor unit over a less expensive gas-fired compressor unit if it needs to site a compressor in an area with strict emission limits.

A. PIPELINE OPERATIONS

Pipeline systems often outlast the transportation market conditions for which they were designed. Notwithstanding the criteria that dictated the original design of a pipeline facility, pipeline companies must adapt their operations in response to changes in delivery markets, supply sources, and possibly new regulatory requirements and business practices.

As a result of FERC's competitive initiatives in Orders 636 and 637, customers have substantial flexibility in how they use pipeline capacity. For example, customers actively use flexible receipt and delivery point rights and the ability to segment their capacity into many transportation paths. They also may nominate transportation quantities at a minimum of four times per day. Gas controllers, who could previously anticipate demand based on weather or typical usage patterns and efficiently "pack the pipeline" to get ahead of events, now must anticipate shipper nominations that reflect day-to-day commodity market conditions, which may have no relation to historic usage patterns on which the pipeline company previously relied. Further, with the increased use of capacity release, the pipelines now transport gas for new customers, who may have very different usage patterns than the original shipper. A pipeline company must schedule customers' transportation requirements, even if the customers' requested schedule/demands do not reflect the most efficient path to move the gas to where it is most needed.

Flow patterns on natural gas pipeline systems have become a lot "peakier." Most pipeline companies with a traditional LDC and industrial customer base designed their pipelines to serve their customers during a winter peak. The pipeline often did not run at full capacity the rest of the year. Now, industrial load has decreased and there are new peaking electric generation customers. For example, peak shaving power generation has created a summer peak load with large swings in flow from morning to afternoon when air conditioning load peaks. This compares to the traditional winter peak heating loads that had two daily peaks, morning and evening. The electric power generators are dispatched with very little notice from their Independent System Operators (ISOs) and, accordingly, the generators provide the pipeline company with very little notice when they need service, thus placing greater demands on the system. As a result, some pipelines recently increased the number of daily nomination windows to 96 (i.e., every 15 minutes) to accommodate power plant demands for no-notice and short-notice service. The rapid response required to meet this demand often causes the compressors to operate outside their optimal efficiency zone, increasing fuel consumption and decreasing thermal efficiency.

In short, due to the obligations to meet customer contractual commitments, real world pipeline performance often falls short of the efficiencies that could be achieved in optimal, steady state conditions. Both the LDC that experiences a cold snap and the electric generator that must be dispatched quickly generally are less concerned about fuel efficiency and more concerned about receiving gas when they need it most.

Pipeline companies employ a number of techniques and procedures to maximize system efficiency while satisfying the level of required customer flexibility and fulfilling contractual commitments:

- Flow simulation software allows transient and real time modeling to help operations that rely on higher linepack. This allows the pipeline to flow gas more efficiently, but requires greater operator vigilance and may require quicker and more frequent shutdowns of compression to avoid over-pressure.
- Shortening the outage time of high efficiency equipment. When high efficiency equipment is out of service (either planned or unplanned), the pipeline company either uses less efficient back-up equipment, or else runs the system less efficiently by increasing the load on downstream compressors. Outage times can be reduced significantly by bringing high efficiency equipment back on line sooner. This can be accomplished, for example, by paying overtime to have maintenance staff work longer hours or weekends, or by paying a premium to have OEMs expedite repair work.
- Consistent with the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's (PHMSA's) regulations, pipeline companies may seek authority to increase their pipeline's MAOP to increase throughput and thereby reduce

compressor fuel usage. Increasing the MAOP increases the pipeline's system transportation capacity and efficiency.[17]

B. PIPELINE MAINTENANCE AND RETROFIT OPPORTUNITIES

Pipeline maintenance has evolved over time, from fixing broken components to preventive maintenance that avoids equipment failure, to predictive maintenance that uses sophisticated data collection and interpretation technology to prioritize maintenance based on computerized analysis. Innovations that the pipeline industry has adopted as best practices prevent damage to the system, ensure reliability and safety, and maximize component life and operating efficiency. This has helped reduce the outage time and increase the availability of high efficiency equipment.

Pipeline companies monitor their systems in a variety of ways to determine if the system is running efficiently, and to establish the optimum maintenance and repair schedule. For example, companies regularly pig lines to remove liquid and solid impurities or obstructions that increase friction and reduce throughput capacity. Pipeline companies launch instruments so-called "smart pigs" to look for potential problems such as metal loss, wall deformations, cracks, and corrosion. This avoids taking a pipeline segment out of service, which would result in less efficient operation. When new connections are need, a procedure known as "hot tapping" allows the work to be conducted without removing the line from service.

Pipeline companies routinely maintain and replace wearable parts such as compressor valves. Compressor valve failures are the single largest cause of unscheduled downtime and maintenance at a reciprocating compressor station. The primary reason that pipeline companies shut down reciprocating compressors, whether scheduled or unscheduled, is to replace a compressor valve. Pipeline companies often match certain valve types with compressor types to create the best seal. There are trade-offs between valve types such as durability, efficiency, maintenance requirements, and cost. Due to advancements in technology, valves now can accommodate compressors that run faster and at higher temperatures. Valves now incorporate condition monitoring systems and other longer life technologies (using semi-active control

[17] One INGAA member company received a special permit from PHMSA to increase the MAOP of its pipeline to 80 percent SMYS rather than 72 percent. This led to an eight to nine percent improvement in transportation efficiency when operated at peak conditions.

methods to reduce impact velocities). If individual components (e.g., compressor poppet valves) improve with new technology, they are incorporated in legacy compressor units.

Pipeline companies also consider the following upgrade or retrofit opportunities:

1. Re-wheeling a centrifugal compressor: This process involves changing the internals of a compressor with an impeller of different diameter or capacity – a bit like changing the gear ratio of an automobile's gearbox to suit different driving conditions. If operating conditions vary significantly from original design conditions, a centrifugal compressor will operate less efficiently and re-wheeling may be economic. These operating conditions sometimes change over a yearly seasonal cycle, while other times the changes are attributable to longer term supply and demand changes (e.g., supply basin depletion).

2. Retrofitting a reciprocating compressor with a new cylinder: Reciprocating compressors can be retrofitted with an improved compressor cylinder design, rated for higher pressures or designed to accommodate new load steps.

3. Advanced pulsation control system designs: The pulsation control system also can be modified at the same time using advanced pulsation controls designed for higher efficiency and less horsepower loss.

4. Engine controls improvement: New engine controls will increase the thermal efficiency of some older reciprocating engines.

5. Electric motor options: Replacing an engine-driven system with an adjustable speed drive electric motor is a retrofit option to accommodate the wide throughput range through speed variation more efficiently than other reciprocating compressor capacity control techniques. This is not commonly done because of limits on the electric motor auxiliary systems or availability and cost of electric power.

C. THE ECONOMICS OF EFFICIENCY UPGRADES

As described above, efficiency opportunities are readily incorporated into new pipeline design. Once built, pipeline companies monitor system components, including compressor stations, to determine whether to repair, modify or, if necessary, replace an entire compressor unit or other system component or otherwise add new technology to improve fuel economy. The industry operates over 6,000 natural gas-fired reciprocating engines, 1,000 natural gas-fired combustion turbines, and 200 electric motors.[18] Yet, just as a car owner does not automatically replace the car or the engine just because a more fuel efficient model has been introduced, a pipeline company cannot justify economically replacing system components to keep in lock step with every state-of-the-art efficiency development.

For example, because the installed costs of natural gas pipeline compressor units have about doubled over the past 15 years, and they are long-lived assets, the cost of a new state-of-the-art replacement compressor unit typically far exceeds the cost of the original unit or the expected fuel savings over a 10 to 15 year period. Accordingly, replacing a legacy unit often is not necessary (since older, properly maintained units can work for many years) or cost-effective even though there is more efficient equipment available. Efficiency upgrade or retrofit decisions can be quite complicated.

Replacing a representative compressor unit with a 10,000 horsepower automated compressor unit with average efficiency may cost $35 million. See Table 3 below. A more efficient compressor unit costs almost $44 million (approximately 25 percent more, and with multiple units to provide greater efficiency the costs jumps upwards of 50 percent more). When gas prices are $4/Dth, it would take 15.6 years to recover the cost of the more efficient compressor, a time period that may not be acceptable to some pipeline companies. Even if the pipeline company wished to invest in the more efficient compressor, the pipeline company may purchase the less expensive, albeit less efficient, alternative if it was competing against other pipelines for business based on the lowest transportation rate.

[18] The actual number of compressor stations is far fewer than the number of engines and motors, because multiple engines or motors typically are grouped at a single compressor station.

Table 3. Compressor Replacement Comparison

Gas Cost	$4.00/Dth		
Compressor size	10,000 hp		
	Heat rate	**Annual Fuel Cost**	**Capital Cost**
Average efficiency	8,000 Btu/hp-hr	$2,242,560	$35,000,000
Best efficiency	6,000 Btu/hp-hr	$1,681,920	$43,750,000
Annual savings		$560,640	$8,750,000
Payout in years if unit operates at 80%		15.6 years	

In order for a pipeline company to recoup the cost of such an investment, a pipeline company either may file a general rate case to recover the cost of the investment in its rates or it may decline to file a rate case and be at risk for recovering those costs either through fuel savings (if the pipeline is on a stated fuel rate) or through additional throughput if the compressor provides relatively cheap expansibility. In either scenario, the investment must be economically justified.

There are a number of reasons why a pipeline company may be hesitant to file to recover these increased costs through a general section 4 rate case. Most prominently, a rate increase likely may be resisted by customers, who will look for rate reductions to offset these cost additions. Further, should the rate increase be too high, customers may take the first opportunity to leave the system for a lower cost pipeline or demand rate discounts (leaving the pipeline company at a risk of under-recovery for those costs) to remain on the system. So, even if a pipeline company could justify its rate increase and charge higher rates, customers with competitive alternatives could demand deep discounts, effectively negating the pipeline company's ability to collect the cost of the efficiency improvement. As discussed above, the competitive market for natural gas transportation has given customers substantial bargaining power. Further, a pipeline company cannot raise the rates charged under negotiated rate contracts to cover the cost of an efficiency improvement through a section 4 filing. The pipeline company only can achieve a rate increase for "recourse" customers—i.e., those paying the generally applicable rate pursuant to Part 284 of FERC's regulations. Moreover, unless the NGA section 4 proposal can be confined to cost recovery for a specific efficiency improvement – which it generally cannot – the section 4 filing opens up all the pipelines' costs and revenues for reevaluation and potential litigation.[19] That is a great disincentive to propose a section 4 rate increase to recover the cost of a discrete efficiency investment in, for example, a replacement compressor, because it effectively turns the economic analysis from that investment into an economic and risk analysis of the overall finances of the pipeline in the section 4 context.

With these caveats in mind, the following cases illustrate some of the calculations involved in the retrofit-replacement-upgrade decision. One INGAA member company considered replacing 16,000 hp with new state-of-the-art internal combustion engines that were 34 percent more efficient (thermal efficiency) than the existing engines at design conditions. The return on investment in fuel savings alone was estimated to require 20 years – much too long to justify this type of investment, which would normally be undertaken on a two to five year return. Other variables affecting the decision included natural gas prices, unit utilization, off-design efficiency and frequency of off-design conditions. Due to these other factors, the efficiency advantage is not always sufficient to justify the upgrade cost. In this case, the pipeline could not justify going forward with the replacement and the project was cancelled.

As with any retrofit/replacement, a pipeline's cost savings or other operational benefits from a newer unit can change if the pipeline's design assumptions change or later prove to be inaccurate. Specifically, a change in the assumed price of natural gas can dramatically affect the fuel saving payback period of a more fuel-efficient compressor. Similarly, if the pipeline company must discount its rates during the payback period greater than expected, the length of the payback period will increase. Further, if the compressor unit is not utilized as assumed because of changes in flow patterns (due to declines in local gas production, change in customer usage, etc.) the payback period for the investment may be much longer than assumed, making the investment not as economic as it should have been. Finally, because pipelines do not operate at design conditions year round, a replaced compressor unit will not always achieve design efficiency if it either operates less than expected or operates at off-peak conditions. A pipeline

[19] *But see Columbia Gulf Transmission Company*, Order on Technical Conference and Proposed Rates, 131 FERC ¶ 61,156 (2010), where the Commission clarified that "pipelines may establish, in limited section 4 filings, an incentive fuel mechanism whereby the pipeline agrees to charge customers fixed fuel rates below the cost-based level the pipeline could otherwise justify, in exchange for a share of the savings that result from the capital improvements made under the incentive mechanism." Order at 61,690.

will not see the savings from the new compressor during the anticipated payback period if the compressor operates less than projected. Similarly, the reliability and estimated maintenance savings for the unit may have to be adjusted to reflect actual operational usage as discussed above. Lower run times result in lower fuel savings. If the design assumptions change prior to installation, the pipeline may decide not to move forward with the replacement/retrofit. If the compressor unit is installed already, the investment obviously will not achieve the desired return on investment and may make the investment uneconomic.

All retrofit options must be evaluated on a case-by-case basis to consider the installed cost, the long-term viability of the station, expected changes in operating conditions and maintenance cost savings. While technologies developed over the last 30 years have created means to improve the efficiency of drivers and compressors, each case must be looked at individually to assess whether the realizable efficiency gains for the expected operational range of the units justify the return on investment.

CONCLUSION

Throughout its history, the interstate pipeline industry has adopted and invested in technology that has produced continuous gains in the overall efficiency of the natural gas pipeline network. Moreover, pipeline companies have responded to the newly competitive environment by implementing additional efficiency gains that have benefited consumers.

The greatest opportunity for maximizing both the economic and transportation efficiencies of a pipeline system is during the initial design and construction stage, when the optimum combination of pipe size, compression, and compressor unit components is chosen to meet projected demand. Once a pipeline has been built, initial design choices limit the ability of the pipeline company to improve transportation efficiency later by replacing individual system components or by modifying the pipeline system. Key considerations in the decision whether to undertake efficiency upgrades are the upfront investment cost, the degree of efficiency to be gained and the cost recovery period. Those calculations in turn depend on the remaining useful life of compressor stations and compressor components, whether new equipment can be incorporated into the existing system, changes in operating conditions and maintenance cost savings, and fuel or other cost savings.

The competitive commercial environment created by the restructuring of wholesale natural gas markets and FERC's open access transportation program has substantially affected the industry's ability to make transportation efficiency investments. In this competitive industry, with pipeline-on-pipeline competition, customers have considerable bargaining power and may be unwilling to pay for efficiency investments that do not have a tangible benefit to them. A pipeline that seeks to recover the investment through a rate increase risks losing customers with competitive alternatives, or risks alienating the customers without alternatives on whom the cost increase would fall. Moreover, as a result of the many additional service options available to customers, many customers are unwilling to commit to the long-term transportation contracts that previously prevailed in the industry, adding additional risk for the pipeline company to recover its capital investments in long-term efficiency improvements.

Throughput levels and off-design operation also can have an important impact on efficiency. When pipelines respond to rapidly shifting customer demand – as they frequently must do today to meet electric power generation load – compressors operate outside of their optimal efficiency zone, increasing fuel consumption and decreasing thermal efficiency. On the other hand, the interstate pipeline industry's ability to ramp up quickly to meet that demand through off-design operation serves the broader energy efficiency interests of the Nation insofar as it meets the need of peaking power plants and renewable (but intermittent) fuel sources.

Stringent environmental regulations also affect efficiency by, for example, influencing route, compressor station siting, and compressor selection (whether the pipeline must install an electric motor-driven compressor versus another selection which may be more efficient under the circumstance). Moreover, uncertainty over the timing and content of proposed climate change regulations affect equipment choices and may deter investment in efficiency improvements.

In sum, each pipeline system is a unique product of its initial design, the technology available at the time of construction, subsequent expansions and modifications, and market and regulatory conditions that shape the demand and expectations of pipeline customers. As a result of this evolution, technologies that may improve efficiency or be cost effective on one system may not be feasible or economic on another. Therefore, a one-size-fits-all approach to transportation efficiency in not practical.

Appendix A: Pipeline Efficiency Background

The transportation efficiency of the pipeline system (η_{sys}) is a combined product of the pipeline hydraulic efficiency ($\eta_{pipeline}$), which measures losses between compressor units, and the compressor unit efficiency ($\eta_{station}$), which includes both driver (thermal) efficiency and compressor efficiency. See Figure A-1.

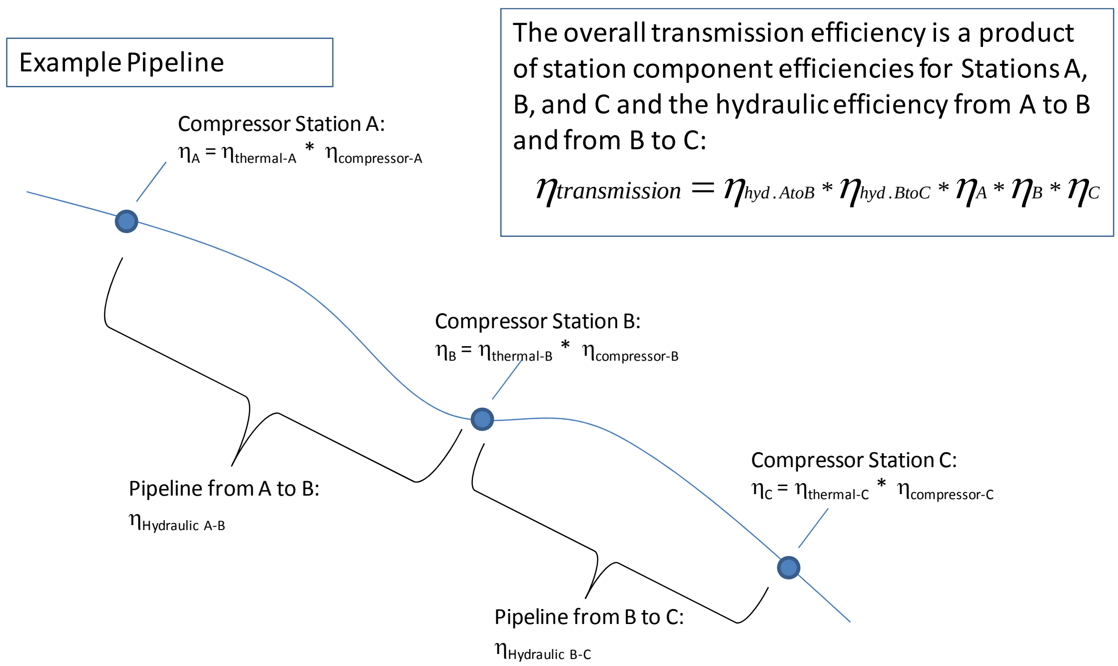

Figure A-1. Example Pipeline Related Efficiencies

Pressure loss along the pipeline is relevant to transportation efficiency because pressure loss will add to the total energy cost of transporting the natural gas, causing actual work to be further from the ideal work used to transport the gas. Higher pressure loss equates to more actual work, which lowers the transportation efficiency. Compressor stations located along the pipeline keep the gas flowing by boosting the pressure of gas to compensate for pressure losses along the line. Higher gas pressure in the flowing pipeline means that the molecules are packed together more tightly and more gas can be transported at the same velocity. Using higher gas pressure and maintaining relatively low velocities is an effective means of increasing hydraulic efficiency (e.g., reducing pressure loss) for the same throughput since the velocity of the gas has a greater influence on pressure loss. The pressure loss is related to friction, the length and diameter of the pipe and the individual pressure losses due to obstructions such as bends, valves or flow meters. Larger diameter pipelines have less surface area per unit of volume than smaller diameter pipelines and, therefore, result in less pressure drop. A smoother internal pipe surface (utilizing internal wall coating) will cause less pressure loss due to friction. Also, the shorter the distance the gas travels and the straighter the pipeline in which it flows, the less the pressure will drop. Correspondingly, fewer obstructions (valves, flow meters, etc.) in the pipeline will reduce pressure loss. Still, pipeline diameter is the biggest single variable in hydraulic efficiency for a given design load. For example, a 24-inch diameter pipeline can move four times the volume of gas as a 12-inch diameter pipeline at a given gas velocity and pressure through the pipe, yet costs only about twice as much to construct and costs virtually the same to operate.

The compressor unit efficiency (a product of the driver and compressor efficiencies) and the pipeline hydraulic efficiency between compressor stations are variables that affect the overall system transportation efficiency. It also is worth noting that there is a minimal pressure drop affecting the compressor station efficiency due to hydraulic losses in the station piping on the suction and discharge sides of the station. When designing its system, a pipeline company tries to optimize hydraulic efficiency through pipeline routing, diameter and operating pressure selections, and unit efficiency through its compressor unit selections (including the engines, turbines, or electric motors that power the compressors).

Appendix B: Compressor Technology Operating Characteristics

Different types of compressors are suited for different applications or services conditions, as depicted in Figure B-1, below. This figure illustrates how reciprocating compressors (single or multi-stage), centrifugal compressors (single or multi-stage) and axial flow compressors at a specified pressure ratio and flow requirement. The y-axis shows the discharge pressure variation considering a constant inlet suction pressure. This effectively represents the range of compression pressure ratios. The x-axis shows the flow rate range for each compressor. Reciprocating compressors are used for high differential pressures and lower flow rates. Multi-stage centrifugal compressors can reach a larger overall flow rate but lower compression ratio compared to multi-stage reciprocating compressors. Axial machines typically are used for very high flow rates with small pressure ratios.

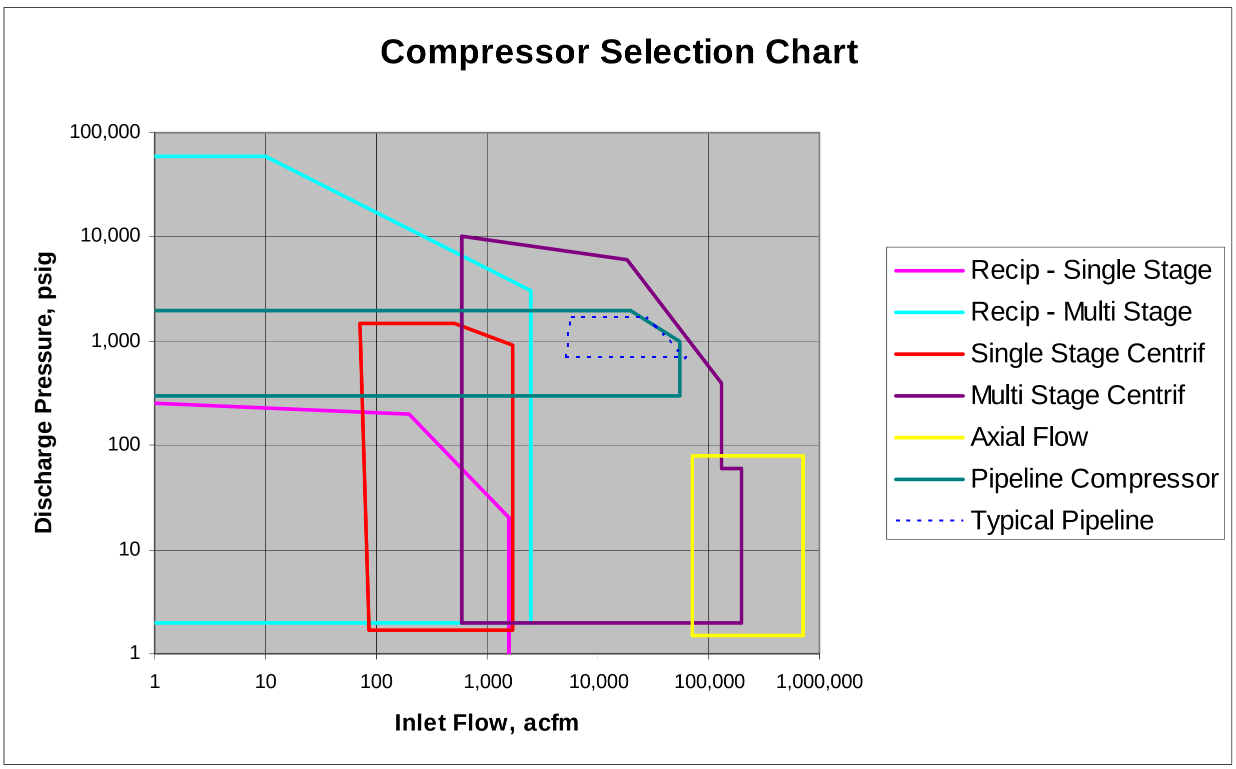

Figure B-1. Compressor Selection Chart

Reciprocating compressors are best suited for low-flow, high pressure ratio scenarios; centrifugal compressors for higher flow low and medium pressure ratio scenarios. Multiple units in series or parallel permit operation of either type at higher flows and pressure ratios.

Compressor technology tradeoffs can be depicted by plotting the efficiency curve against expected operating conditions (expressed in terms of either the expected flow range or pressure ratio range).

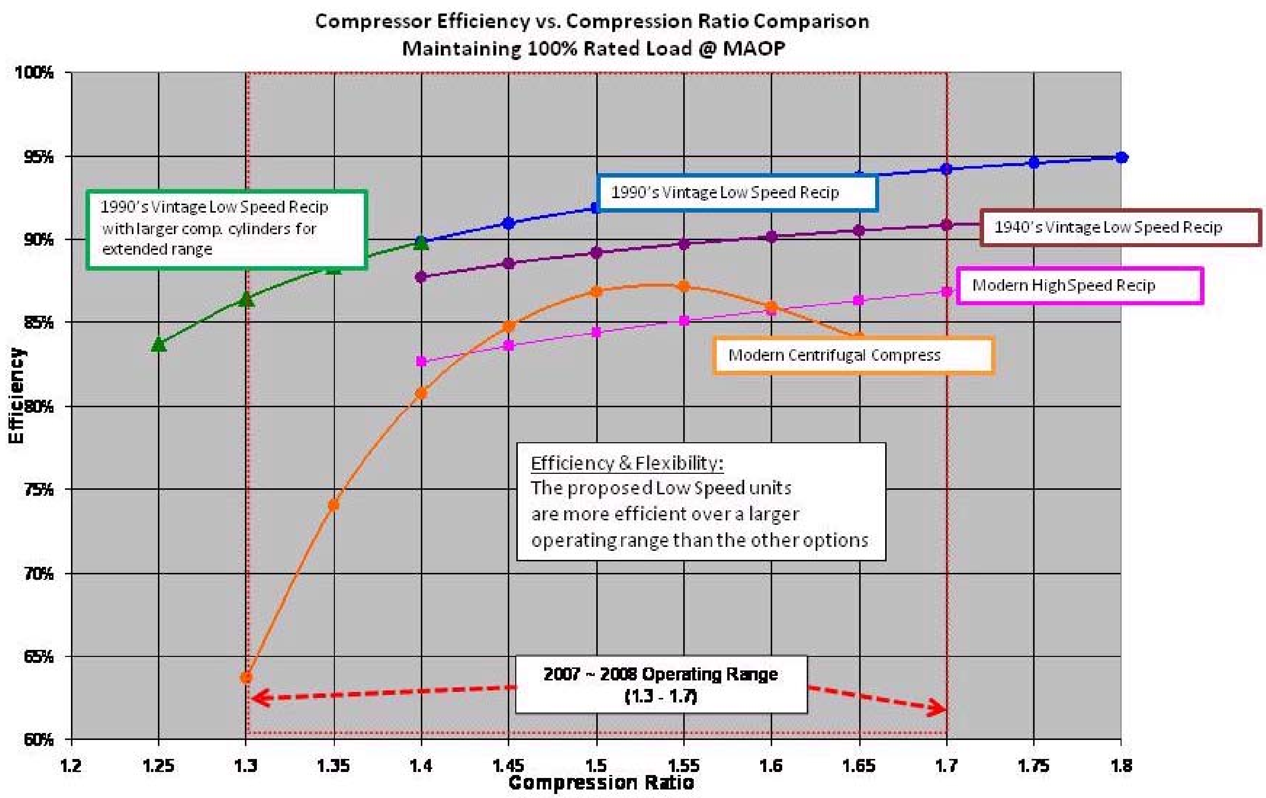

Figure B-2. Compressor Technology Efficiency versus Pressure Ratio

Figure B-2 plots the relationship in terms of efficiency versus compression ratio as the primary purpose of a compressor station is to boost the pressure. The comparison of compressor technologies includes older equipment and modern, high speed reciprocating compressors and centrifugals compressors. The operating parameters and range of each technology vary greatly. The lower speed reciprocating compressors offer a greater efficiency and range for compression ratios compared to modern high speed reciprocating compressors and modern, centrifugal compressors. Still, Figure B-2 assumes a constant flow rate. When operated at a constant speed at lower rates, the efficiency of reciprocating compressors will suffer more severely than the efficiency of centrifugal compressors.

A typical interstate pipeline operates with discharge pressures between 900 to 1750 psig and flows between 400 to 3,000 MMcf/d. For a pipeline with a large flow rate turndown, a centrifugal compressor is the preferred technology from an efficiency standpoint. Lower speed reciprocating compressors offer a greater efficiency and range for large variations in pressure ratio compared to modern high speed reciprocating compressors and modern centrifugal compressors.

When operated at a constant speed and lower flow rate than the design point, reciprocating compressors generally are less efficient than centrifugal compressors. If a pipeline operates outside of the design parameters of the unit (in terms of pressure ratio or flows), the compressor will use greater fuel than at design conditions because of diminished efficiency. This may be cause for modifying the unit. The primary advantage of a reciprocating compressor is its ability to produce high pressure ratios. Such compressors do, however, have high flow limitations. These characteristics make reciprocating compressors particularly desirable in gas gathering or storage injection services, which generally have relatively low flow requirements. Multiple units must be used for high flow service such as mainline interstate pipeline transportation.

Compared to centrifugal compressors, slow speed reciprocating compressors maintain higher efficiency over a wider bandwidth of operating pressure and gas flow conditions (operating range), but they are more costly to install. Reciprocating compressors have a wide range of operational flexibility. The efficiency of these compressors declines at lower flow rates, depending on capacity control options such as such as volume pockets, valve unloaders, and deactivators.

High speed reciprocating compressors (900 to 1200 rpm) often suffer more losses than low speed reciprocating compressors in the cylinder valves and pulsation control system. Lower speed compressors (200 to 400 rpm) tend to be more efficient for the overall compressor system, but may not be driven by the highest efficiency engine due to the age of the equipment. New slow speed reciprocating compressors can be paired with modified or new state-of-the-art reciprocating engines to deliver high compression efficiency within a wide range of operation, albeit at a higher up-front capital cost.

A centrifugal compressor can handle the very high flows that are characteristic of interstate pipelines, but they have pressure ratio limitations. Multi-stage units must be used for high pressure ratio service. Table B-1 briefly summarizes the advantages and disadvantages of reciprocating and centrifugal compressors and their associated prime movers.

Table B-1. Compressor Technology Operating Characteristics at Design Conditions

Prime Mover Technology	Prime Mover Efficiency (percent)	Compressor Type	Compressor Efficiency (percent)	Unit Efficiency (percent)	Advantages	Issues
Reciprocating Compressors						
Legacy slow speed IC engine (200-400 RPM)	27-30	Integral reciprocating	80-92	22-28	–	– Waste heat recovery not economic – Less efficient and higher maintenance cost than legacy slow speed engines
Legacy slow speed + low emissions retrofit (200-400 RPM)	33-35	Integral reciprocating	80-92	26-32	– Compact units	– Waste heat recovery not economic; heat dispersed between exhaust gases and cooling – No longer manufactured
New slow speed IC engine (200-400 RPM)	30-43	Slow speed separable reciprocating	80-92	24-40	– Multi-engine compressor station responds to demand variability more efficiently – Higher partial load efficiencies than turbines – More responsive to varying pressure ratios than centrifugal compressors – Slow speed unit are established infrastructure base with legacy of reliability – May be skid mounted for lower installed cost – Can be variable speed to maintain flexibility	– Larger compressor cylinder design (and more costly) required for similar throughput to high speed machine
Medium speed engine (500-900 RPM)	32-46	Medium speed separable reciprocating	75-90	24-39		– Higher initial unit cost than turbine units – Waste heat recovery not economic – Higher maintenance cost than legacy slow speed engines
High speed recip (900-1200 RPM)	32-43	Separable high speed reciprocating	70-82	22-35		– Lower initial cost than slow speed reciprocating engine – Losses in valves and pulsation bottles are high
Synchronous speed electric motor (360 RPM)	25-46*	Slow speed separable reciprocating	80-92	20-42	– No on-site emissions, simplifies permits	– Requires access to power – Torsional considerations – Speed fixed at 360 RPM (60 Hz)
Centrifugal Compressors						
Legacy gas turbine	22-27	Legacy centrifugal (1950-1980)	71-80	16-22	- only available technology at time for large power	– No longer manufactured
Turbine (< 5 MW)	24-31	Centrifugal	75-88	18-27	– Lower initial cost than reciprocating compressors – Waste Heat concentrated in exhaust gasses; CHP applications if a thermal host is nearby	– Heat recovery for electric generation requires 11+ MW – Lower partial load driver efficiency – Lower offload compressor efficiency
Turbine (5 - 20 MW)	27-36	Centrifugal	75-88	20-32		
Large Turbine (>20 MW)	29-40	Centrifugal	80-88	23-35		
Large Turbine with waste heat recovery (ORC) for electric power generation	33-47	Centrifugal	80-88	26-41	– Electricity may provide revenue stream – Demand for "green" power – Organic Rankine Cycle is more compact with no fluid condensation	– Requires large turbine (11+ MW) – Requires high load factor – Requires close grid access – Possible revenue pass-through requirements – Capital investment requires long-term contract with utility – Regulatory and permit complications. – ORC is less efficient than a steam cycle
Large Turbine with waste heat recovery (steam-based) for electric power generation	34-55	Centrifugal	80-88	26-48	– Electricity may provide revenue stream – Demand for "green" power – Increases efficiency	– Issues listed above for ORC system – Freeze-up in cold weather – Require 24/7 steam operator – Capital investment requires long-term contract with utility
Large Electric motor driven off electrical grid (3600 RPM)	25-46*	Centrifugal	80-88	20-40	– No on-site emissions, simplifies permits – Low capital cost – Low maintenance for motor	– Requires access to power – Cost associated with interconnection and transformer – Power provider may have minimum demand charge – Supply reliability – Generation of electricity at power plant may produce high emissions – Transmission of power also involves high losses especially if distances are great

*Heavily depends on source power generation losses. Electric motor site efficiency can reach 90 to 95 percent efficiency.

Source: INGAA

Appendix C: Internally Coated Pipe Comparison

Internally coated pipe is a design option for reducing the pressure losses and increasing hydraulic efficiency of a pipeline system. Internal coating is most beneficial when a pipeline is operating near 100% of design capacity. The fuel savings associated with low flows does not offset the initial cost of the internal coating, which can explain why many variable or lightly loaded pipelines were not internally coated. Its benefit must be weighed against the significant cost of the coating. Figure C-1 compares pressure drop versus flow rate for internally coated and uncoated pipe. In this example, internally coated pipe required less horsepower than uncoated pipe, reducing fuel from 1.627 to 1.452 MMcf/d. The cost of internal coating can vary between $2 to $8 per foot, depending on pipeline diameter and the type of coating, e.g., fusion bond epoxy. Additional costs may arise if the pipe mill where the steel was ordered is unable to coat the pipe and the pipeline company must ship the pipe to another manufacturer for coating, possibly resulting in construction delays. Under most circumstances, the cost of replacing old vintage steel pipe with newer, more efficient internally coated pipe would be prohibitive because the efficiency gains would not justify the cost.

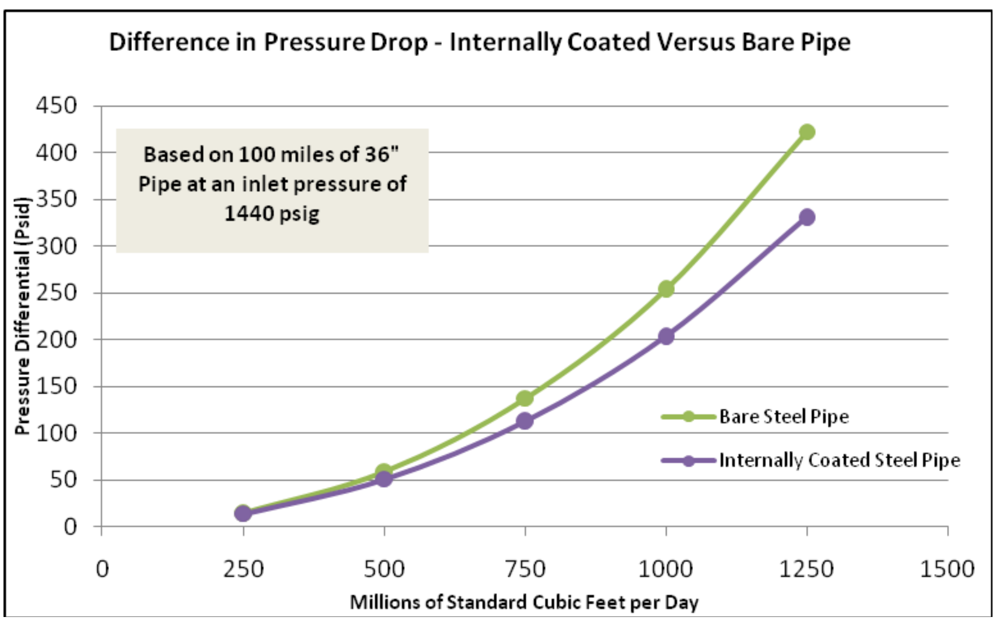

Figure C-1. Pressure Drop on Internally Coated Pipe as a Function of Flow

Appendix D: Compressor Station Location Effect on Efficiency

The location and spacing of compressor stations is another important factor in overall pipeline transportation efficiency. Pipeline companies use advanced simulation programs to determine the best compressor station locations and spacing, considering cost as well as physical space availability, permitting, and reliability needs (for stations at closer locations). The simulation illustrated in Figure D-1 provides an example of the trade off between delivered transportation cost for natural gas vs. pipe mileage that can be used to determine optimal station spacing. The chart shows how the smaller, 30-inch diameter pipelines require shorter spacing between the compressors stations (approximately 60 miles) to achieve the lowest toll because of the increased pressure drop associated with the higher velocities in the smaller diameter pipe. The larger, 36-inch and 42-inch diameter pipelines have a lower pressure drop and therefore can accommodate a wider spacing between stations (80 miles and 100 miles, respectively) to achieve the lowest toll. Still, such decisions cannot be made solely on the basis of reducing cost while optimizing efficiency. Environmental, landowner, and other siting considerations often dictate spacing that is less than optimal from an engineering perspective.

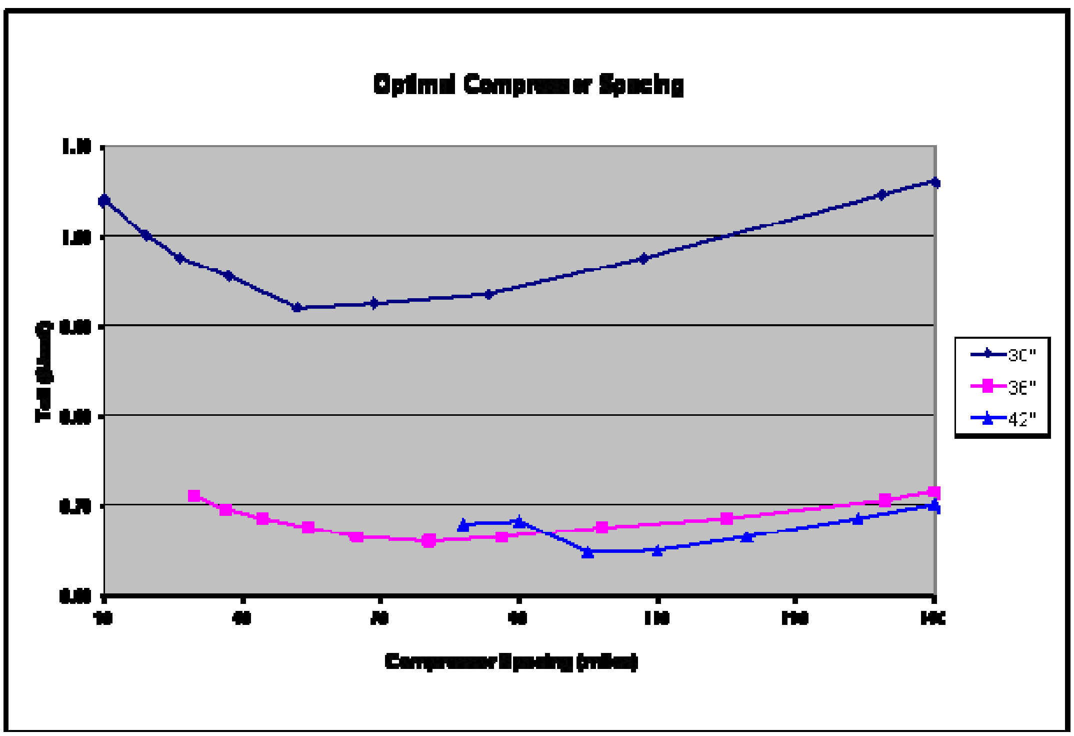

Figure D-1. Optimal Compressor Spacing for Lower Cost per Transported Mcf of Gas per Mile

Appendix E: Recent Research and Development Studies

Study Title	**Contractor**	**Year**
Ultrasonic Meter Testing for Storage Applications	SwRI, DOE	1998
Introduction to Smart Pigging in Natural Gas Pipelines	GRI, INGAA, Battelle	2000
Reciprocating Compressor Valve Design: Optimizing valve life and reliability	Derek Woollatt, Dresser-Rand	2002
Turbocharger Center Helps Advance Natural Gas Compression	K.S. Chapman, Pipeline and Gas Journal	Oct 2002
Additional Studies of the Effects of Line Pressure Variations on Ultrasonic Gas Flow Meter Performance	GTI	2003
Increased Flexibility of Turbo-Compressors in Natural Gas Transmission Through Direct Surge Control	SwRI, DOE	2003
Development of an Inspection Platform and a Suite of Sensors for Assessing Corrosion and Mechanical Damage on Unpiggable Transmission Mains	DOE, Northeast Gas Association, Foster-Miller, Inc.	2004
Development of Low-Cost Inferential Natural Gas Energy Flow Rate Prototype Retrofit Module	SwRI, GRI, DOE	2004
Field Testing of Remote Sensor Gas Leak Detection Systems	DOE NETL	2004
Metering Research Facility Program: Additional Studies of Orifice Meter Installation Effects and Expansion Factor	GTI	2004
Metering Research Facility Program: Effects of Turbine Meter Cartridge Change-out on Measurement Uncertainty	GTI	2004
Metering Research Facility ISO Uncertainty Analysis	GTI	2004
Metering Research Facility Program: Pressure Effects and Low Flow Tests on 8-Inch and 6-Inch Ultrasonic Flow Meters	GTI	2004
Practical Guidelines for Conducting an External Corrosion Direct Assessment (ECDA) Program	GTI, Corrpro Companies, GRI	2004
Remote Detection of Internal Pipeline Corrosion Using Fluidized Sensors	NETL, SwRI	2004
Advanced Reciprocating Compression Technology	SwRI, DOE	2005
Airborne, Optical Remote Sensing of Methane and Ethane for Natural Gas Pipeline Leak Detection	DOE NETL, Ophir Corporation	2005
Improvement to Pipeline Compressor Engine Reliability through Retrofit Micro-Pilot Ignition Systems – Phase III	Colorado State University, DOE	2005
Metering Research Facility Program: Line Pressure and Low-Flow Effects on Ultrasonic Gas Flow Meter Performance	GTI	2005
Metering Research Facility Program: Natural Gas Sample Collection Handling – Phase V	GTI, SwRI, GRI	2005
Technologies to Enhance the Operation of Existing Natural Gas Compression Infrastructure – Manifold Design for Controlling Engine Air Balance	SwRI, DOE	2005

Virtual Pipeline System Testbed to Optimize the U.S. Natural Gas Transmission Pipeline System	Kansas State University, DOE	2005
Guideline for Field Testing of Gas Turbine and Centrifugal Compressor Performance	GMRC, SwRI	2006
Gas Storage Technology Consortium	DOE, Pennsylvania State University, PRCI	2009
Surge Prevention in Centrifugal Compressor Systems	Rainer Kurz and Robert White, Solar Turbines	2007
Evaluate Existing Hydrocarbon Dew Point Measurement Methods & Equipment	PRCI	2008
Alternatives to Gas Expansion Starters	PRCI	2009
Gas Turbine Emissions Compliance	PRCI	2009