Electricity Production from Natural Gas Pressure Recovery Using Expansion Turbines

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ABSTRACT

The transport of natural gas in the U.S. accounts for roughly 3.4% of U.S. natural gas consumption. Expansion turbines, which capture the energy from high-pressure gas transmission, can harness some of this transport energy. This paper provides an overview of expansion turbines and their use. We analyze three case studies and estimate the potential for expansion turbine use in the U.S. and find that expansion turbines have the potential to generate a theoretical maximum of 21 TWh in industrial and utility settings, recovering 11% of natural gas transport energy as electricity.

Introduction

In this paper we examine the use of expansion turbines to generate power using pressure from the natural gas transmission grid. Expansion turbines use the pressure drop when natural gas from high-pressure pipelines is decompressed for local networks to generate power. Most assessments of the potential for cogeneration—the combined generation of heat and power—focus on traditional forms that use natural gas-fired turbines or steam cycles with a variety of fuels. Expansion turbines (also known as generator loaded expanders) actually serve as a form of power recovery, utilizing otherwise unused pressure in the natural gas grid. In 1999, the U.S. consumed roughly 610 Bm^3 (22 Tcf) of natural gas (EIA, 2000). About 3.4%, or 20.8 Bm^3 (735 Bcf), of that natural gas was used as pipeline fuel (EIA, 2000), powering the compressors that provide transportation energy for natural gas through the pipeline system. While it is necessary to transport natural gas at high pressures, end-users require gas delivery at only a fraction of main pipeline pressure. Pressure is generally reduced with a regulator, a valve that controls outlet pressure. Expansion turbines can replace regulators. These turbines offer a way to capture some of the energy contained in high-pressure gas, not through combustion, but by harnessing the energy released as gas expands to low pressure, thus generating electricity. This paper examines the likely applications of expansion turbines, using case studies to help estimate their potential primarily in industry and the utility sector. This paper also provides overviews of natural gas production and transmission, which affect the potential for expansion turbine utilization.

Natural Gas Exploitation and Transportation in the United States

Natural gas is collected, treated in the field, compressed, and piped to a central processing facility. After gas is processed, it is moved to a pipeline system for transport. Gas is transmitted at high pressures, from 200 to 1500 PSI (14 to 100 atm), to reduce the volume of the gas and provide a propelling force to move gas through the pipe (NGSA, 2000). In order to maintain adequate pressure, natural gas needs to be compressed periodically as it moves through a pipeline. The 8,000 compressor stations in the U.S. are located about every 100 miles along a pipeline (NGSA, 2000). Most compressors are classified as reciprocating compressors. A portion of the natural gas flowing through the pipeline powers the compressors. The natural gas transportation process consumed roughly 3.4% of total natural gas use in 1999, most of which powered compressors (EIA, 2000). This is the energy that can be partially recovered by expansion turbines as electricity.

Local distribution companies (LDCs) deliver gas from interstate pipelines to local consumers. They are responsible for changing pressure for local users. LDCs are generally either privately owned by shareholders, or publicly owned by local governments of cities, counties, or by special utility districts. While some large gas users buy directly from marketers, most residential, commercial, and industrial customers obtain natural gas through LDCs. Some LDCs generate and distribute power along with natural gas. Many LDCs could incorporate expansion turbines into their gas-distribution network, as they have access to the large pressure drop as gas moves from an interstate pipeline to a local network.

The flow of natural gas in the U.S. is shown schematically in Figure 1. After gas is gathered and processed, it is compressed and shipped along interstate pipelines at an average of 48 atm (700 PSI). While a few large users take gas directly off interstate lines, almost all natural gas is routed through a local distribution company. When gas enters a local distribution main line, pressure is reduced via regulator to an average of 7 atm (100 PSI), then further reduced to an average of 1.4 atm (20 PSI). Large industrial facilities and utilities generally receive gas at pressures between 30 and 650 PSI (2 and 44 atm). Commercial facilities may receive gas up to 5 PSI (0.34 atm), while most house connections require gas to be delivered at 1 PSI (0.07 atm).

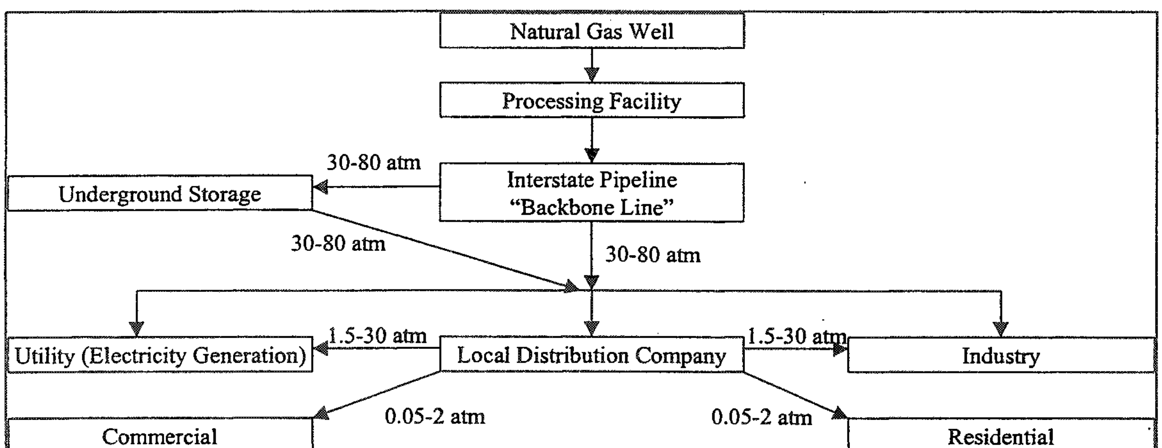

Figure 1. Schematic Overview of Natural Gas Transport and Distribution

Natural gas use in the U.S. increased at 2.3% per year between 1986 and 1999, rising from 450 Bm^3 (16 Tcf) to 610 Bm^3 (22 Tcf). Natural gas use is expected to increase at 1.8% per year through 2020, with demand forecasted to reach 900 Bm^3 (32 Tcf) in 2020 (EIA, 2000). Pipeline expansion has accompanied the increased demand for natural gas. Pipeline companies made major investments to the U.S. pipeline system during the 1980s and early 1990s, improving capacity and efficiency. Pipeline capacity grew 16% between 1990 and 1999, and pipeline use rose from 68% to 72% average daily use of capacity over the same period. While interregional pipeline capacity grew at 3.3% per year between 1990 and 2000, it is predicted to grow at only 0.7% per year between 2000 and 2020 (EIA, 1999). Much of the growth in consumption is forecast in the electricity generation sector, which will increase system load factor, and result in less need for capacity expansion. Overall, natural gas consumption, pipeline capacity, and pipeline utilization are all increasing. While the growth in pipeline use will not necessarily entail growth of available pressure resources at the same rate, the necessary infrastructure for expansion turbines is in place and growing.

Of the approximately 614 Bm^3 (21.6 Tcf) of natural gas consumed in 1999, 563 Bm^3 (19.9 Tcf) was delivered to customers. Industry used roughly 41%, residential locations 22%, and commercial and utility locations used 14% each (EIA, 2000). The difference was used as pipeline fuel (used to power compressors), and lease and plant fuel. The 3.4% used to transport natural gas amounts to roughly 200 TWh of primary energy per year. This quantity of natural gas is comparable to the amount used in the primary metals industries (MECS, 1997), and is worth $2 billion at 1999 prices.

Technology Description

In this paper, an expansion turbine is defined to include both an expansion mechanism and a generator. Simply put, in an expansion turbine high pressure gas is expanded in a manner where it is made to produce work. Energy is extracted from pressurized gas, which lowers gas pressure and temperature. Created in the 1930s, these turbines have been used for air liquefaction in the chemical industry for several decades (MTC, 1997). The application of expansion turbines as energy recovery devices started in the early 1980s (SDI, 1982b). In this paper, we discuss the use of expansion turbines both to lower gas pressure through expansion and to generate electricity.

A simple expansion turbine consists of an impeller (expander wheel) and a shaft and rotor assembly attached to a generator. High-pressure gas is routed from a pipeline through an expander casing, which leads to the expander wheel. The high-pressure gas spins the expander wheel, which spins the rotor and shaft assembly, which in turn produces electricity via the generator. Gas is exhausted at a lower pressure. Expansion turbines are generally installed in parallel with the regulators that traditionally reduce pressure in gas lines. If flow is too low for efficient generation, or the expansion turbine fails, pressure is reduced in the traditional manner.

The drop in pressure in the expansion cycle causes a drop in temperature. While turbines can be built to withstand cold temperatures, most valve and pipeline specifications do not allow temperatures below −15°C. In addition, gas can become wet at low temperatures, as heavy hydrocarbons in the gas condense. Gas generally enters an expansion turbine at ground temperature, and expansion from this temperature leaves gas too cold for further transmission upon exiting the expansion turbine. This necessitates heating the gas just before or after expansion. The heating is generally performed with either a combined heat and power (CHP) unit, or a nearby source of waste heat. Using a CHP unit may reduce the economic performance of electricity generation, as part of the gas flow must be burned to generate heat. The efficiency of power generation is still much higher than conventional natural gas electricity generation, however. Using waste heat improves the efficiency of the system beyond that of CHP-heated electricity generation. It is also possible to use the refrigeration energy from expansion, where applicable. One of the facilities in the case studies uses natural gas for the heating process, while the other two installations use waste heat for heating of gas. The expansion process is shown in Figure 2. Figure 2 shows both a CHP heating unit and a waste heat source, though only one is needed. While the heat exchange process can take place either before or after expansion, preheating is shown in Figure 2.

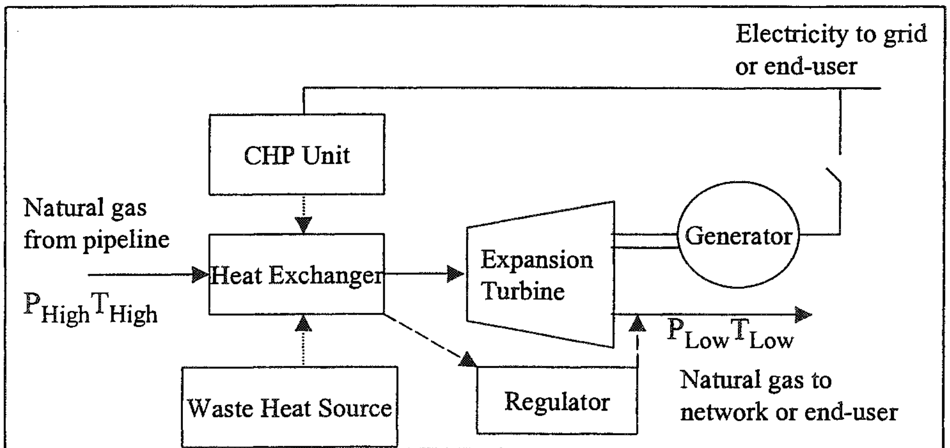

Figure 2. Natural Gas Flow, Electricity Production Using an Expansion Turbine

Gas enters an expansion turbine at a specific temperature and pressure state, which impart it energy (enthalpy). Enthalpy is the product of the internal energy, pressure, and volume. Turbine-expanded gas has a lower pressure and temperature combination, and thus a lower enthalpy. The turbine captures the enthalpy change to generate electricity. While expansion turbines are capable of generating power even with a low change in enthalpy, the required flow becomes very large. For a typical turbine, the low end of acceptable enthalpy changes is 10-20 kJ/kg of natural gas. The high end is roughly 120-150 kJ/kg of gas. The greater the enthalpy change, the greater the potential for power extraction. A typical pressure for gas entering a turbine is 40 to 70 atm (580 to 1020 PSI), with an exit pressure (back pressure) of 5 to 10 atm (70 to 150 PSI) (Pozivil, 2001). The back pressure is dictated by the gas end-use. A typical entry temperature is between 70 and 90°C (160 and 190°F), with an exit temperature between 0 and 10°C (30 and 50°F). These pressure and temperature conditions are not absolute, only typical. Turbines are available for a variety of conditions. The minimum acceptable flow for an expansion turbine is roughly 3000-4000 cubic meters per hour (Pozivil, 2001). Turbine generation potential can be calculated using the enthalpy change and the natural gas mass flow. Multiplying the enthalpy change across the turbine (kJ/kg) times the mass flow (kg/hr) gives energy output in kJ/hr. For power recovery applications, turbines are generally rated from 150 kW to 2500 kW. While expansion turbines are designed for high efficiency at partial loading, they are not as efficient at flows well below design capacity. Generally, expansion turbines can tolerate a 10 to 1 fluctuation in gas flow while still recovering energy efficiently. Maximum enthalpy capture (efficiency) by expansion turbines ranges from 90 to 92% (Cryostar, 2001). While suitable enthalpy changes vary significantly, the most important factor is the flow—how many kilograms of gas are passing through to drive the turbine. Even with a large enthalpy difference, low flow will produce low electricity output. Generally, larger units are more economical than smaller units.

Expansion Turbine Experiences

Most recent state-of-the-art expansion turbine installations are found outside the U.S. We review three case studies for our analysis, two in the Netherlands, and one in Japan. One of the projects in the Netherlands uses a gas pressure drop to generate power for the utility grid, while the other generates power for onsite use. The project in Japan utilizes the pressure and temperature drop of expanding gas in a district heating and cooling facility both to generate power and to cool water.

Energie Bedrijf Amsterdam, Amsterdam, The Netherlands

The first expansion turbine installation we examine is located at a gas and electricity distribution utility in the Netherlands. The national gas company, Gasunie, transports gas to local utility companies and generally handles pressure drops in a conventional reduction line (using regulators). The Amsterdam Utility Company, with permission from Gasunie, installed an expansion turbine in October 1991 in parallel with an existing pressure-reduction line. The expansion turbine draws gas from the regional grid at 40 atm (580 PSI) and expands it through an expansion turbine to 8 atm (120 PSI). The flow rate of natural gas through the turbine varies between 25,000 and 110,000 m^3/hr (0.9 to 3.9 million ft^3/hr). The mass flow for the system is 6.1 to 27.7 kg per second. The gas enters the system with an average temperature of 8°C (46°F), and is preheated to 80 to 95°C (175 to 200°F) before entering the turbine. Six gas-fired CHP units, along with three auxiliary boilers, manage the preheating. The gas passes through the turbine and is expanded, powering the turbine, which is rated at 4000 kW at maximum flow (CADDET, 1994).

The turbine generated 12,022 MWh of electricity in 1992, while the CHP plant produced 8,421 MWh, along with the heat required by the installation. The system generated a total of 20,443 MWh, with an input of 27,861 MWh of natural gas energy to the CHP plant (CADDET, 1994). The combination of gas-fired CHP units and an expansion turbine produced electricity with an efficiency of 73%. We used National Institute of Standards and Technology (U.S. DOC, 2001) data to calculate the enthalpy change in natural gas (assuming 100% methane) before and after passing through an expansion turbine. The expansion turbine captures roughly 89% of the available energy in the natural gas flow as electricity.

The total cost of the installation was roughly $6.8 million, with annual operation and maintenance costs of $160,000 per year. The natural gas used to fire the CHP plant costs roughly $400,000 per year, while the turbine and CHP plant produce $1.5 million of electricity each year, at the 1992 Dutch electricity price of 7 cents per kWh. Natural gas costs for preheating amounted to roughly 30% of electricity revenues. With total annual costs of $560,000 per year, there is a net income of $940,000 per year, which results in a simple payback period of 7.6 years (CADDET, 1994).

Corus, IJmuiden, The Netherlands

The second case study we examine is a 1994 turbine installation at a Corus integrated steel mill. The mill receives gas at roughly 63 atm (930 PSI), preheats the gas, and expands with the turbine to 8 atm (120 PSI). The maximum turbine flow is 40,000 m^3/hr (1.4 million ft^3/hr), while the average capacity is 65%, resulting in an average flow of 26,000 m^3/hr (0.9

million ft^3/hr), or 5.8 kg/second. The primary difference between this project and the Amsterdam Utility Company (EBA) project is the source of preheating energy. While the EBA project requires a CHP plant to preheat gas prior to expansion, the Corus project uses waste heat from a hot strip mill, in this case cooling water of approximately 70 °C (160°F), to preheat the gas (van Ginkel, 2000).

The 2 MW turbine generated roughly 11,000 MWh of electricity in 1994, while the strip mill delivered a maximum of 12,500 MWh of waste heat to the gas flow (de Jong, 2001). Thus, roughly 88% of the maximum heat input to the high-pressure gas emerged as electricity.

The cost of the installation was $2.6 million, and the operation and maintenance costs total $110,000 per year. Unlike the EBA case, there is no gas cost, as the strip mill's waste heat is provided at no charge. With total costs of $110,000 per year and income of $710,000 per year from electricity generation (at the 1994 Dutch electricity cost of 6.5 cents per kWh), the payback period for the project is 4.4 years (de Jong, 2001).

Osaka Gas Company, Ltd., Japan

Osaka Gas supplies natural gas and liquefied natural gas to the Kansai region of Japan. In an effort to improve energy efficiency through utilization of waste energy, Osaka Gas installed an expansion turbine in a district heating and cooling facility (DHC) in Osaka in 1994. The DHC supplies cold water of 7°C (40°F), and hot water of 80°C (180°F) to the surrounding area, and is adjacent to a large gas pressure regulator station. Gas enters the system at roughly 6 atm (80 PSI) and is expanded with the turbine to 2 atm (20 PSI). There are two temperature modes for expansion. When there is demand for cooling energy, gas enters the turbine at 20°C (70°F), and exits at –30°C (-90°F). This is normally too cold an exit temperature, but the gas is heated after expansion, before re-entering the distribution network. Cool water of 13°C (55°F) is used to heat the gas after expansion. This heat exchange cools the water to the desired 7°C (40°F) for DHC distribution. Thus, the gas is heated while providing refrigeration work. When there is little demand for cooling energy, the gas needs to be preheated before expansion. In this case, waste heat from the DHC (cooling water of 80°C [180°F]) is used to heat the gas to 65°C (150°F), and it emerges from expansion at 10°C (50°F) (Sugiyama, 1998). When the gas is preheated, there is no cooling energy generated. Pre- or after-heating is determined by demand for cooling energy. The maximum flow rate for the system is 53,000 m^3 (1.9 million ft^3) per hour, with an average capacity of about 30% (Matsumoto, 2001).

The case study documents the period between July 1996 and April 1997, when the expansion turbine was run for roughly 2600 hours and generated 1400 MWh of electricity. The turbine was expected to run 5,000 hours per year and generate 2750 MWh of electricity, along with 1900 MWh of energy into cooling water, for a total of 4650 MWh of energy per year. The afterheater provides a maximum of 3,800 MJ of heat, and the preheater a maximum of 5,700 MJ of heat, per hour (Sugiyama, 1998). Osaka Gas provided no information on the proportion of the use of the two heaters, so we assume each is used about 50% of the time. At a use of 5,000 hours per year, the maximum total heat input to the gas is 6600 MWh per year. The conversion of heat to electricity in this system occurs with an efficiency of 42%, while the conversion of heat to electricity and cooling energy has an efficiency of 70%. The expansion turbine captures roughly 74% of the enthalpy change in the natural gas.

The turbine installation in Osaka cost roughly $1.7 million, with operating costs of $40,000 per year (not including labor costs, which were unavailable). The waste heat used for pre- and afterheating is provided free of charge. The project produces $400,000 of electricity per year (using Japan's 1997 electricity price of 14.5 cents per kWh), resulting in a payback period of 4.6 years (Matsumoto, 2001). We do not assign a monetary value to the cooling energy, which would reduce the payback period.

In each of the cases, we have seen that heat input is converted to electricity or other useful work at over 70% efficiency. For the Corus and Osaka Gas projects, the efficiency is probably higher. Thus, it makes sense to put as much waste heat into the gas flow before expansion as possible, especially if the heat is cost-free. In these calculations, we used maximum yearly waste heat consumption figures, as opposed to waste heat figures scaled by average flow capacity, in order to avoid overestimating efficiency. Table 1 summarizes the conditions and results of the case studies we examined.

Table 1. Summary of Case Study Indicators

Indicator	Units	EBA	Corus	Osaka Gas
Pressure In	PSI	580	930	80
Temperature In	K	361		293 (338)
Energy (Heat) In	GWh/year	27.9	12.5	6.6*
Pressure Out	PSI	120	120	20
Temperature Out	K	281		243 (283)
Energy (Electricity) Out	GWh/year	20.4	11.0	2.8*
Maximum Flow	'000 m^3/hour	110	40	53
Average Flow Capacity	%	34%*	65%	30%
Generation Efficiency (heat/output)	%	73%	88%	42%*
Turbine Efficiency (enthalpy /output)	%	89%		74%*
Fuel Expenditures	'000 US$/year	$410	0	0
Electricity Revenues	'000 US$/year	$1500	$710	$400
Installation Costs	'000 US$/year	$6800	$2600	$1650
Operation/Maintenance Costs	'000 US$/year	$160	$110	$40
Simple Payback Period	Years	7.6	4.4	4.6

*- calculated () – preheating - Osaka Gas electricity revenues not including chilled water output

U.S. Experience

There are few current data available on the use of expansion turbines in the U.S. A spokesman for the Interstate Natural Gas Association of America (INGAA) offered that the high gas prices of the early 1980s led to "a lot of work" with expansion turbines. Many installations proved uneconomical due to demand-driven pressure and flow variability. Recent international projects, however, have proven successful.

Expansion Turbine Potential in the United States

We estimated the potential for expansion turbines to recover the energy used in natural gas transmission in the U.S. as electricity, using the EBA and Corus installations as models. The first estimate assumed the use of onsite CHP gas engines for gas preheating, which also supplement expansion turbine electricity production. The second estimate assumes that waste heat was used for preheating, and thus all power generation was a result of gas expansion. By assuming a constant enthalpy change across the turbine, we were able to estimate energy output based on flow.

In order to assess theoretical energy recovery potential in the U.S., we used total customer (563 billion m^3 [19.9 Tcf]), total industrial (88 billion m^3 [3.1 Tcf]), and total utility (power generation) (255 billion m^3 [9.0 Tcf]) gas consumption figures for 1999 (EIA, 2000). We assumed that all of the gas used in each sector would be run through a turbine at a set enthalpy change. In actuality, the gas would come from a combination of proportions of these sectors.

In the EBA example, the turbine and CHP unit produced roughly 62 MWh per million cubic meters of gas passing through the turbine. We assumed a set of conditions similar to the EBA example in the U.S., using total 1999 U.S. gas flows as multipliers[1]. Under these conditions, expansion turbines could potentially generate 35 TWh for the total U.S., including 16 TWh in industrial locations, and 5 TWh in utility locations. These electricity totals are equivalent to $1.4 billion, $600 million, and $200 million in electricity, for the U.S. total, industry, and utilities, respectively, using 1999 electricity prices. The two most suitable sectors, industry and utilities, could produce a maximum theoretical sum of 21 TWh of electricity generation. This is equal to roughly 0.6% of 1999 U.S. net electricity generation (EIA, 2001c). However, roughly 40% of this electricity would be produced by CHP units, with associated gas costs. In the EBA example, about 30% of the electricity revenues were used for gas purchase, which would offset generation revenues. We used the Corus data to calculate a flow multiplier of 48 MWh per million cubic meters of gas. This flow multiplier generated theoretical electricity production estimates of 27 TWh for the U.S., including 12 TWh in industry settings, and 4 TWh in utility settings, equivalent to $1.1 billion, $480 million, and $170 million in 1999 prices, respectively. The electricity generation data are summarized in Table 2. This scenario required no gas input for combustion. The first example generated more electricity than did the Corus scenario, but required gas purchase and combustion for preheating and electricity generation. These estimates are rough approximations of the theoretical limit of expansion turbine electricity production potential. Since pressure drops vary from grid to grid, and the availability of waste heat is unknown, it is impossible to estimate the number and potential capacity of sites favorable to turbine installation. Without a site-by-site review, it is impossible to accurately assess the potential for energy generation and cost savings using expansion turbines.

An important factor in siting is the local price of electricity, which significantly affected the payback period in the EBA and Corus projects. As summarized in Table 3, calculations based on an electricity price of 5 cents per kWh (as prevails in parts of the U.S.) resulted in payback periods of 17, 16, and 6 years for the three projects. Calculations using

[1] The formula used to calculate U.S. expansion turbine energy recovery: turbine installation electricity output (MWh/yr) / (Gas Flow (m^3/yr)X flow capacity (%)) = Ratio of Output to Flow (MWh/m3). Multiplying this ratio by relevant gas flow (i.e. U.S. industry) (m^3/yr) gives potential output in MWh/year.

electricity prices comparable to those in Japan, 15 cents per kWh, resulted in payback periods of 4.5, 2.7, and 1.7 years for the three projects. Higher electricity prices make project economics more attractive. SDI (1982) found that electricity costs greater than 6 cents/kWh brought a payback period less than 3 years. SDI necessitated an electricity cost of only 4 or 5 cents/kWh for a 3-year payback when waste heat was available, or the refrigeration effect was salable. However, we found that payback period varied significantly by site, and that no general guidelines could be set for minimum electricity prices.

Table 2. Theoretical Expansion Turbine Electricity Generation Potential in the U.S.

	Output/Gas Flow (MWh/1e6 m^3)	Industry (TWh)	Utility (TWh)	U.S. Total (TWh)
EBA Model (with CHP)	62	16	5.5	35
Corus Model (waste heat)	48	12	4.3	27

Table 3. Simple Payback Period as a Function of Electricity Cost

	Payback Period (years)		
Electricity Price	**EBA**	**Corus**	**Osaka Gas**
5 cents/kWh	15	6.0	17
10 cents/kWh	4.6	2.7	7.1
15 cents/kWh	2.7	1.7	4.5

Discussion

Expansion turbines have the potential to recover a significant amount of natural gas pressure energy and convert it to electricity. It is difficult to make an accurate assessment of the total potential energy recovery within the U.S., as potential sites need to be evaluated on a case-by-case basis. Electricity generation from full expansion turbine exploitation of optimal industrial and utility sites could approach a theoretical maximum of around 21 TWh using CHP gas heating, and 17 TWh using waste heat. Electricity generation efficiency of expansion turbine systems ranged from 42 to 88% in the case studies we examined, equivalent to or more efficient than traditional power-generating systems.

There are several functioning installations currently in use. Manufactures supply high-quality site-specific turbines internationally for a wide variety of temperature, pressure, and flow situations. There are no additional safety hazards associated with the turbines, compared to traditional pressure reduction-technology. Osaka Gas uses a bypass regulator to reduce pressure if the turbine is stopped in an emergency. While early U.S. experience with expansion turbines may have been negative, changes in technology have increased reliability and cost-effectiveness of expansion turbine installations. The question is not whether the technology is available and effective, but whether the economics of the turbines make them appealing to users. As early as 1982, SDI found that "concern lay with the economics of the approach, not the technology". The three cases we examined had payback periods of 7.6, 4.4, and 4.6 years. The case that required a preheating installation had a payback period almost double those that had access to a free supply of waste heat. Obviously, reducing energy or operation and maintenance costs improves project economics significantly. Local electricity costs play a major role in determining the viability of a turbine installation as well. In the long term, expansion turbine electricity generation can be profitable, but the start-up costs and payback period may deter potential users.

The costs of gas pressure energy are currently incorporated into transport costs. Estimates of transport costs to residential end users range from 38% (EIA, 2001a) to 66% (EIA, 2001b) of total gas costs. Transport costs for industry and utilities are likely lower, but still substantial. The technology needs to exploit the pressure energy, thereby recapturing part of the transport costs, in an economically favorable manner.

Siting of expansion turbines is important. As more installations appear, it will be easier to assess and identify ideal sites. These sites must have access to a substantial gas pressure drop, a consistent gas flow, a heat source for preheating gas, and some way to use or transmit electricity. While pressures must almost always be stepped down for end-use, not every pressure reduction is appropriate for expansion turbine use. Some gas lines drop pressure in small increments, while some end-users drop pressure little if at all. A consistent gas flow ensures adequate exploitation of the site enthalpy change. Turbines maintain efficiency with partial loading to a point, but even with a large enthalpy change, an uneven or inadequate supply will severely limit turbine efficiency. Heat can be supplied to the natural gas with some sort of fuel-fired heating system, or with by-product heat from another source. While it is possible to add a CHP heat source along with a turbine, having access to waste heat improves the economics of a turbine installation markedly.

Expansion turbine users must also be able to use generated electricity on-site or in some way put it into the grid for sale. Electricity demand and access to the utility grid makes utilities and industrial locations favorable sites. Both these groups must lower the pressure on large amounts of high-pressure natural gas used on-site, and often have access to waste heat. They also have substantial electricity demand or are interconnected to the electricity grid. LDCs represent another viable turbine location. Many of these are classified as utilities, as they both produce power and distribute natural gas. However, LDCs that do not produce or distribute electricity may not be feasible locations for expansion turbine use. While LDCs have access to the majority of high-pressure natural gas in the U.S., they may not have access to waste heat or grid connection. While not all LDC, industrial, or utility sites are ideal for turbine utilization, they represent the most likely sites to explore.

Future Research

The next steps in more accurately evaluating expansion turbine potential and encouraging their use lie in identifying likely sites and installing pilot projects. Is it possible to install expansion turbines anywhere in the gathering and processing stages of natural gas production? What are the optimal conditions with regard to pressure drop and flow rate for expansion turbine use? Is it possible to consolidate multiple gas systems for maximum energy recovery? A model for site analysis and suitability could be developed, which would take into account the various factors necessary for successful turbine installation. Working pilot project demonstrations would assist in identifying sites. It would also be worthwhile to explore whether utilizing the temperature drop in expanding gas is feasible in the U.S., as in the Osaka Gas case study. Is it possible, for instance, that the chemicals or food processing industries, which use substantial amounts of natural gas, could use a turbine installation for both electricity generation and refrigeration energy? As we understand which sites are most suitable for turbine use, we can begin to more accurately estimate the potential of this technology in the U.S.

Conclusions

The preceding discussion of expansion turbines has shown that their operation is technically feasible, with the potential to generate up to 21 Twh in optimal locations, or the equivalent of 11% of natural gas primary energy transmission losses, as electricity. The economics and efficiency of expansion turbine power generation are subject to a variety of local factors. Most important among them are the pressure drop and flow rate of natural gas. The economics of turbine use are much more favorable with a supply of inexpensive waste heat.

The natural gas industry has been growing steadily since the mid-1980s, with gas consumption, and pipeline capacity and utilization increasing overall since 1990. The infrastructure for turbine use is in place and is projected to grow for several decades. As the use of natural gas increases in the U.S., so too does the potential for expansion turbine use. Improving technology and accuracy of site assessment would improve expansion turbine projects. Increased use of expansion turbines in the U.S. will help us more accurately assess their generation and cost-savings potential in the future.

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