The Combined Heat and Power Market for Small

Commercial End-Users in North Carolina

By

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ABSTRACT

Combined heat and power (CHP) is an approach to generating both electricity and usable thermal energy than can offer numerous environmental and economic benefits over more conventional generation methods. Previous research has made clear that the technical potential for additional CHP is huge, yet questions still remain as to how much of this potential is actually economical, and therefore likely to be adopted by end-users.

This report evaluates the economic potential for CHP in the commercial and institutional sectors of North Carolina, with a focus on the relatively small (<1 MW average electric demand) end-users. Using prevailing and projected energy prices and equipment costs for CHP units commercially available in 2007, the likely returns on investment were assessed for the purchase of reciprocating engine CHP systems ranging from 100 kilowatts (kW) to 1,000 kW in capacity. The effect of various financial incentives on investment returns, including rebates and long term, low interest rate loans, was also evaluated.

This assessment finds that given prevailing and projected energy prices, CHP at present would not be an attractive investment for most commercial sector facilities in North Carolina. Facilities that require an uninterrupted source of power, or that are capable of producing their own source of fuel, are likely exceptions, and could potentially benefit economically from CHP even given the state’s relatively low spark spread. While various incentives and low interest loans could significantly improve the economics of CHP for much of the sector, the financial outlay required to do so would likely be on an order of magnitude not currently seen in any state. Taken together, these findings suggest that CHP will likely play a limited role in meeting the state’s energy needs, at least for the foreseeable future.

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I. Introduction

Combined heat and power (CHP) has yet to achieve significant market penetration in the commercial and institutional sectors of most states, despite its many advantages over more conventional generation methods. In North Carolina, only five commercial sector facilities making up a combined 47 megawatts (MW) of capacity have adopted CHP to date. It is estimated, however, that the state's commercial and institutional sectors have the technical potential for over 2,400 MW of CHP (OSEC, 2000; Hedman, 2005). Although substantial, it is important to note that this value was estimated taking only technological constraints into account. It is difficult, without any consideration of economics, to assess the share of this potential likely to be adopted by end-users and the role that CHP is likely to play in meeting the state's future energy needs.

A limited number of studies (e.g. DOE, 2002; EEA, 2005; ERG & EEA, 2007) have previously evaluated the economic potential for CHP for a select number of applications, but considerable change has occurred since the publication of these assessments. Specifically, the cost of natural gas (the predominant fuel utilized by CHP systems) has increased significantly, while forecasts for natural gas and retail electricity rates have been revised. In addition, the cost and performance of various CHP technologies have improved. In general, the potential for additional CHP in the southeast has not been documented as extensively in comparison to other regions (Hedman & Hampson, 2004).

This study is intended to complement the previously published CHP market assessments.
Its primary objectives are to (1) evaluate the economic potential for CHP in the commercial and institutional sectors of North Carolina and (2) determine under which sets of circumstances the

economics of CHP in these sectors are favorable. Probable returns on investment were calculated for the purchase and operation of CHP units under a range of scenarios differing primarily in terms of the natural gas and retail electricity rates that were assumed, as well as in terms of the incentives or subsidies offered for the deployment of CHP. This assessment focuses primarily on the relatively small (<1 MW average electric demand) commercial end-users due to the fact that the largest shares of technical potential were found for this size category (OSEC, 2000).

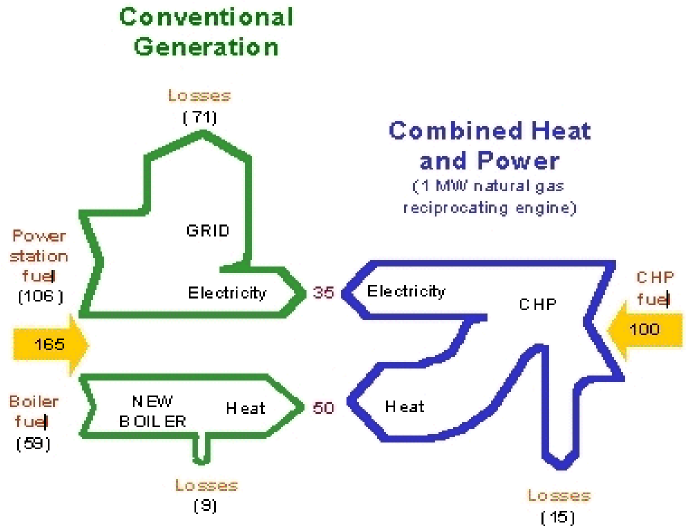
This report finds that CHP is not likely to be an attractive investment for most of the commercial facilities in North Carolina, given prevailing and projected energy prices, as well as the existence of what some would call market barriers to distributed generation. Financial incentives and subsidies could significantly improve the economics of CHP in the state, but would require outlays on an order of magnitude not currently offered by any state. Facilities that are capable of producing their own sources of fuel (e.g. wastewater treatment facilities) or that require an uninterrupted source of power (e.g. brokerage houses) are probable exceptions to these findings and could likely benefit economically from CHP even given prevailing energy prices, perhaps with little or no financial assistance from the state.

II. Background

CHP is a remarkably efficient way of producing both electricity and usable thermal energy. The production of electricity necessarily involves the generation of significant quantities of heat, and in most fossil-fueled, centralized power plants, this thermal energy is simply discharged to the atmosphere or a waterway. In a CHP setup, the heat that is produced along with the electricity is instead recovered and can then be used in a variety of applications, such as space conditioning, steam and hot water production, and drying and cooling. As Figure 1 helps to illustrate, the efficiency of a CHP system can approach 85%, considerably higher than the 50% efficiency typically associated with more conventional generation methods. Put another way, the conventional setup depicted in Figure 1 would require 65% more energy than the CHP unit to produce the same quantities of electricity and usable heat. The location of the CHP system at or near the end-user, as is typical, will result in additional energy savings by avoiding the transmission and distribution losses associated with the generation of electricity at centralized power stations (Brooks et al., 2006; EPA, 2007). The increased energy efficiency of CHP can help to reduce a facility's energy costs, given a sufficiently high spark spread, and also help in reducing emissions of carbon dioxide and other pollutants.

CHP offers numerous other benefits, as well. The typical placement of CHP units at or near the end-user can make the need for costly upgrades to the power grid's transmission and distribution infrastructure unnecessary (Brooks et al., 2006), and can also help to improve the quality and reliability of a facility's electricity (EPA, 2007). For a number of market sectors, including hospitals, telecommunications centers, airports, various manufacturers, brokerage operations and credit card operations, power outages or voltage surges can be remarkably costly or damaging (USCHPA, 2001). For example, it is estimated that power outages can cost brokerage operations on the order of $6,480,000 each hour; credit card operations $2,580,000 an hour, and airline reservations centers $90,000 an hour (SE CHP, 2006). Power quality disruptions may also impose direct costs on businesses by damaging sensitive equipment (Darrow et al., 2005).

Figure 1: Conventional Generation Versus CHP



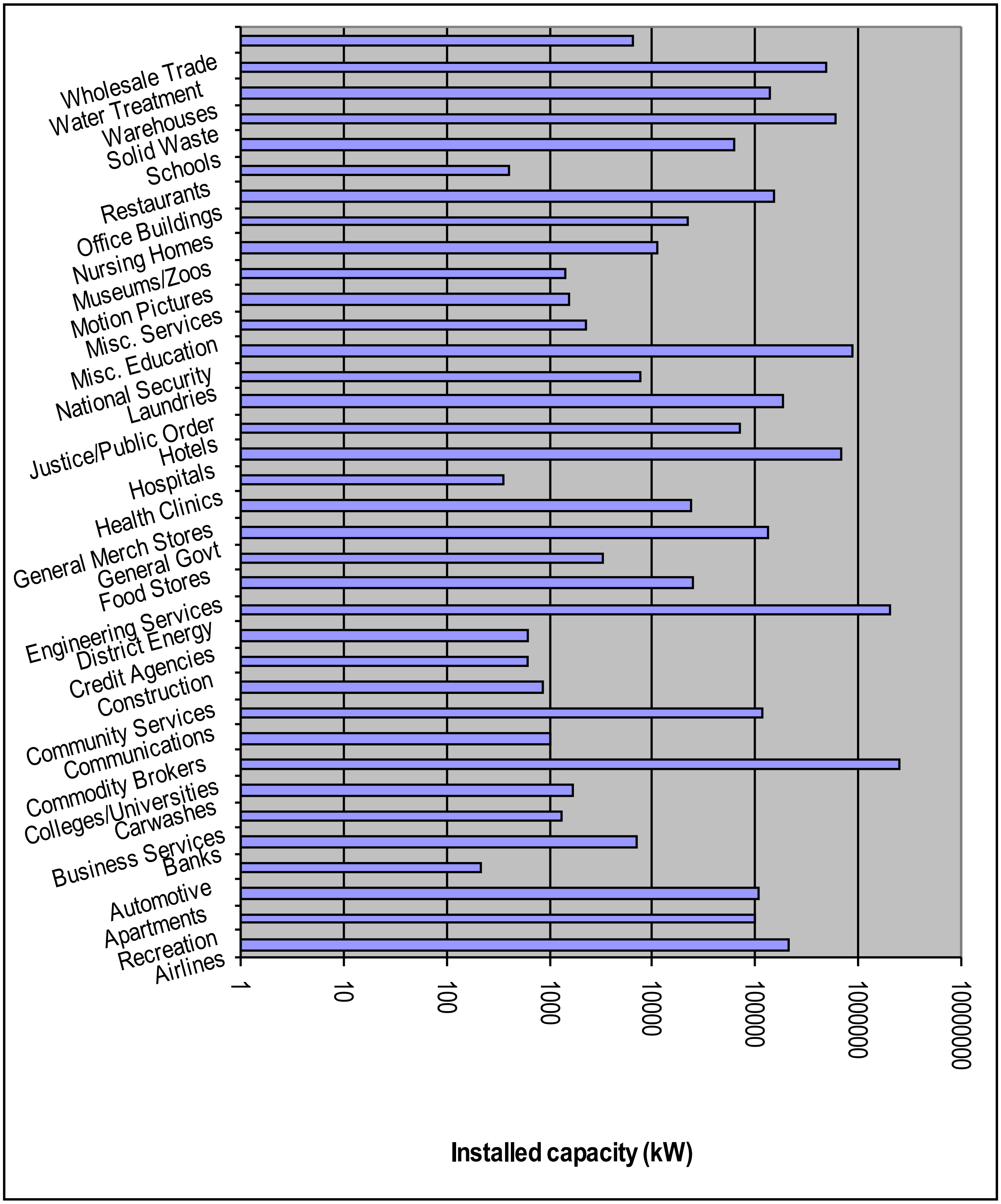
Source: Southeast Combined Heat and Power Application Center.

Despite these potential economic and environmental benefits, the nation's existing CHP represents only a modest share, roughly 7.5%, of the nation's total electric generating capacity (EEA, 2007; EIA, 2007). These CHP systems have been installed at over 3,100 facilities across all 50 states, range in size from several kilowatts (kW) to several hundred megawatts, and combined make up over 84,000 MW of capacity. Almost all of the installed capacity has been installed in the industrial sector, and at present, the chemical, petroleum refining, and paper industries represent 60% of the nation's existing CHP capacity. Furthermore, over half of the nation's CHP has been installed across just five states, including Texas, California, Louisiana, New York, and Florida. The market penetration of CHP in North Carolina has been much more limited by contrast. To date, 45 facilities across the state have installed a combined 1,480 MW of capacity. The textile, chemical, and paper industries have installed the largest shares of this capacity (EEA, 2007).

CHP has yet to achieve the same degree of market penetration in the commercial sector as it has in the industrial sector. Although more than 1,600 commercial facilities across the country have installed CHP to date, these units make up just 10% of the nation's existing capacity. Moreover, roughly one third of this capacity has been installed across two states, New York and California. A diverse set of commercial sector enterprises has adopted CHP, however, as summarized in Figure 2. Colleges and universities as well as district energy facilities have clearly installed the most CHP to date, and together account for over half of the sector's existing capacity. Installations at hospitals, solid waste facilities, and military facilities combined represent another quarter of the existing capacity (EEA, 2007).

The deployment of CHP in the commercial sector of North Carolina has been quite limited. A total of five commercial facilities representing a combined 47.3 MW of capacity have adopted CHP within the state so far. A large share of this total, 28 MW, has been installed at the University of North Carolina in Chapel Hill. Another relatively large system, over 10 MW in size, has been deployed at a solid waste facility. Two installations at military facilities make up a combined 7.5 MW of capacity while another system at a hospital makes up the remaining 1.8 MW of capacity (EEA, 2007).

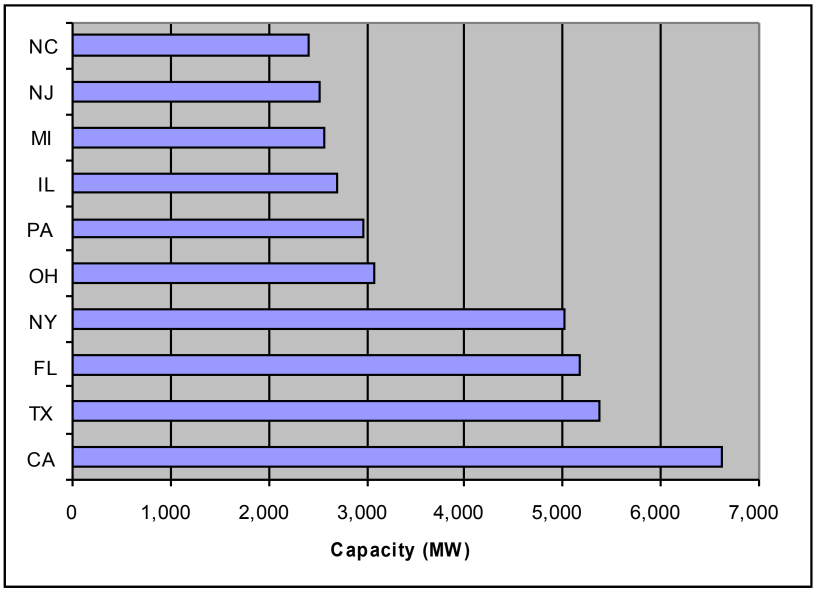
Figure 2: Existing Commercial Sector Capacity, United States



Source: Derived from EEA (2007) data.

The potential for additional CHP within the commercial sector is great. A comprehensive analysis of the sector (OSEC, 2000) found that some 230,000 sites nationwide have the electric and thermal loads necessary to support an estimated 75,000 MW of additional capacity, assuming the systems were sized to meet the average electric demands of each site. Almost all states were found to have the technical potential for at least several hundred megawatts of added capacity, with the potentials for some states estimated to be on the order of 2,500 MW (Figure 3). California and the northeast were found to have the most substantial potential for additional CHP, over 20,000 MW altogether. This assessment found significant opportunities for CHP development in North Carolina's commercial sector, as well. Estimated at 2,400 MW, the state's technical potential is actually among the nation's highest. As previously noted, however, the market penetration of CHP in the state's commercial sector is currently quite low; most of the capacity has been installed at one location. California and the northeast, on the other hand, have so far seen the installation of much more CHP in their respective commercial sectors.

Figure 3: Commercial Sector Technical Potential, Top 10 States



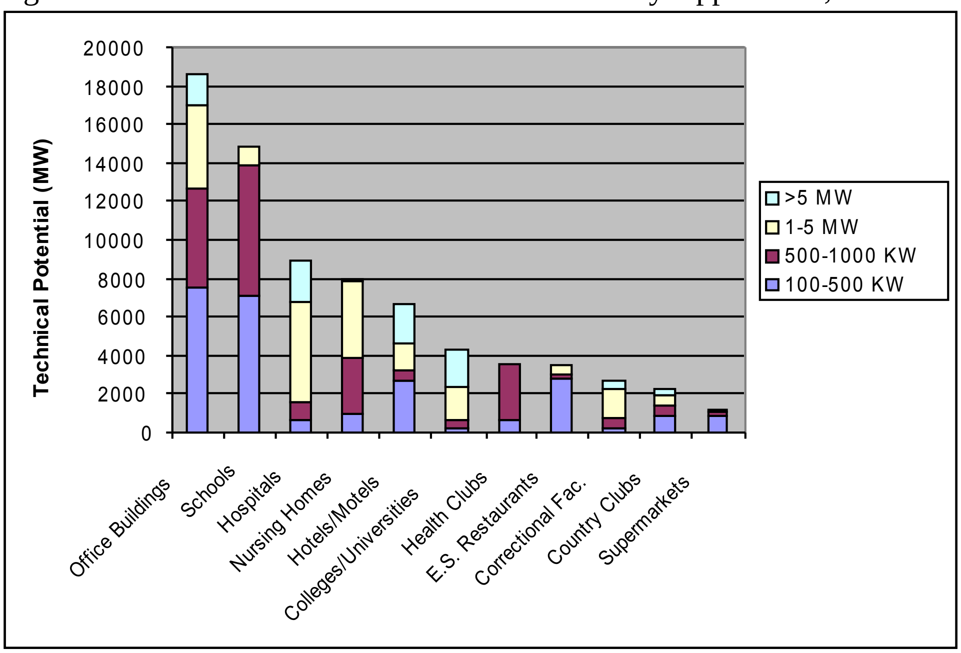
Source: Derived OSEC (2000) data.

Figure 4 lists the eleven commercial and institutional applications found to have the most substantial potential for CHP. While significant opportunities for further deployment clearly exist across a wide range of applications, three applications, including office buildings, schools (to be distinguished from colleges and universities), and hospitals, account for about 55%, or an estimated 41,600 MW, of the nation's CHP potential in the commercial sector. Nursing homes and hotels and motels, which together represent nearly 15,000 MW of potential, are also good markets for CHP. These five applications combined represent roughly three quarters of the commercial sector's technical CHP potential, and of these applications, only hospitals currently have significant existing capacity. Although not included in Figure 4, commercial laundries, car washes, museums, water treatment facilities, and refrigerated warehouses also have a combined 2,800 MW of CHP potential. These types of facilities have little existing CHP capacity (OSEC, 2000).

Similar to the nation as a whole, the largest opportunities for additional CHP development in North Carolina are found for schools and office buildings. An estimated 466 MW of technical potential exists in the state's schools alone, with another 424 MW of potential in office buildings. North Carolina's nursing homes and hospitals are also amenable to CHP, each with an estimated 300 MW of potential. These four applications account for over 60% of the state's total technical potential. Hotels and motels, colleges and universities, health clubs, correctional facilities, and extended service restaurants are also good candidates for CHP in the state (Figure 5).

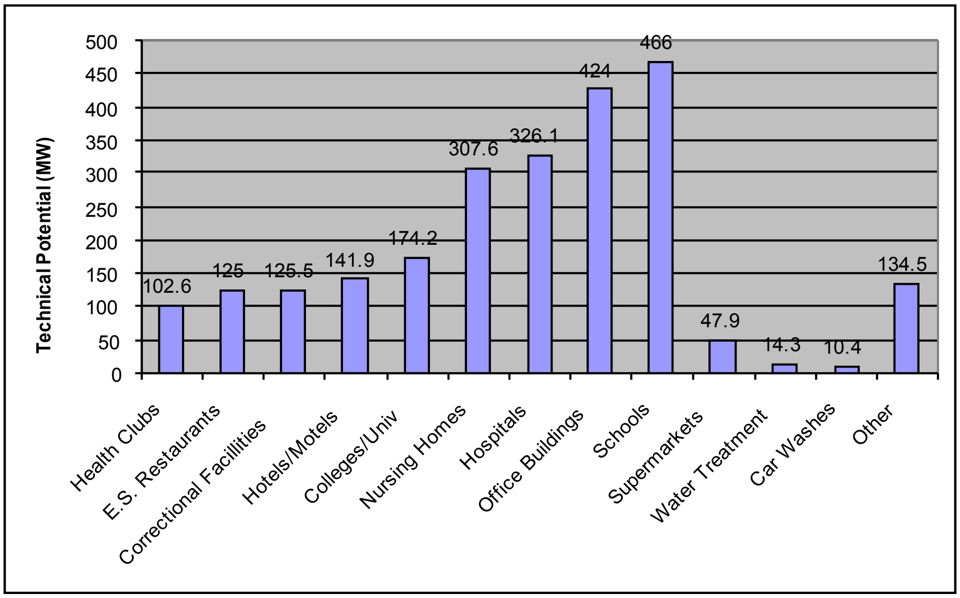
It should be noted that a remarkable amount of the potential for additional CHP is in smaller systems. The electric and thermal loads for the applications found to have the greatest technical potential for CHP, including office buildings, schools, hotels and motels, and nursing homes, could typically be satisfied with CHP systems ranging in size from 100 KW to 1 MW. For the nation as a whole, nearly 48,000 MW of technical potential exists at facilities that have average electric demands under 1 MW. The bulk of the technical potential in North Carolina, over 1,500 MW, is also found in the 100 to 1000 kW size range (OSEC, 2000). To date, however, most of the nation and state's commercial sector CHP has been in larger sized systems at colleges and universities, military/national security sites, hospitals, district energy facilities, and solid waste facilities (EEA, 2007).

Figure 4: Commercial Sector Technical Potential by Application, United States



Source: Derived from OSEC (2000) data.

Figure 5: Commercial Sector Technical Potential by Application, North Carolina

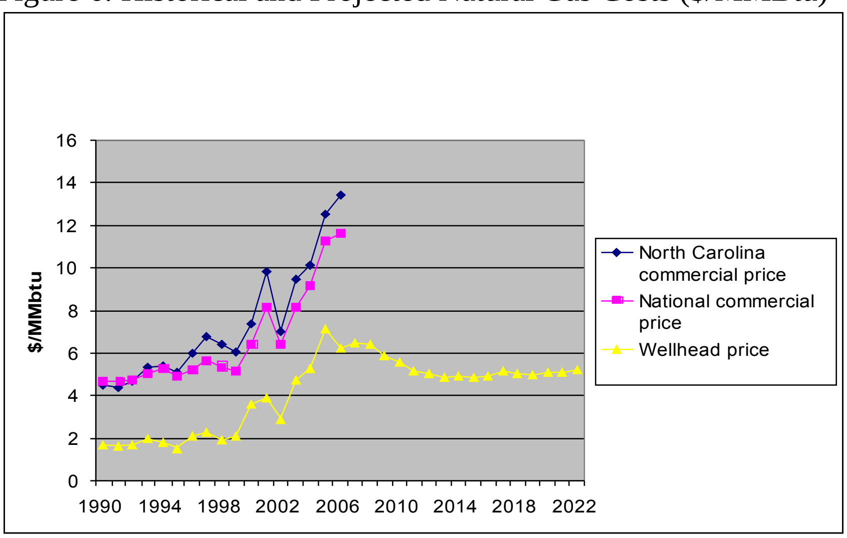


Source: Derived from OSEC (2000) data.

Since the technical potential for CHP is estimated taking only technological constraints into account, it is difficult to state with certainty the share of this potential that is economical, or, in other words, that would actually provide a return on investment attractive enough to warrant the purchase of a system. Many factors influence the economic viability of CHP, and since natural gas is the predominant fuel for CHP units, foremost among these factors are prevailing and projected natural gas prices. All else equal, an increase in the cost of natural gas will usually make CHP more expensive and therefore less attractive. Facilities that are capable of producing their own sources of fuel, such as wastewater treatment facilities, are exceptions to this rule. For such facilities, research has illustrated that rising natural gas prices make CHP more attractive (EEA & ERG, 2007). In recent years, the cost of natural gas for commercial sector facilities has increased significantly in North Carolina, from an average of \$5.63/MMBtu in the 1990's to an average price of over \$10.00/MMBtu since 2000. A similar trend has been observed for the country as a whole, as costs have risen from \$5.22/MMbtu in the 1990's to just over an average of $9.00/MMbtu since 2000 (EIA, 2007b). These trends, for both North Carolina and the country as a whole, are shown in Figure 6.

Also shown in Figure 6 are historical and projected wellhead gas prices for the country. Over the long term, it is clear that wellhead prices are projected to decrease from current levels, due in part to the expected construction of new LNG terminal capacity and the increased importation of natural gas. The anticipated construction of an Alaskan gas pipeline to transport natural gas to the lower 48 states as well as the increased production of unconventional gas resources will also help to reduce prices over the longer term. The Energy Information Administration (EIA) expects that commercial natural gas prices will follow the same downward trend as wellhead prices, but as Figure 6 suggests, it is not anticipated that commercial rates will return to the levels seen in the 1990's (EIA, 2007c).

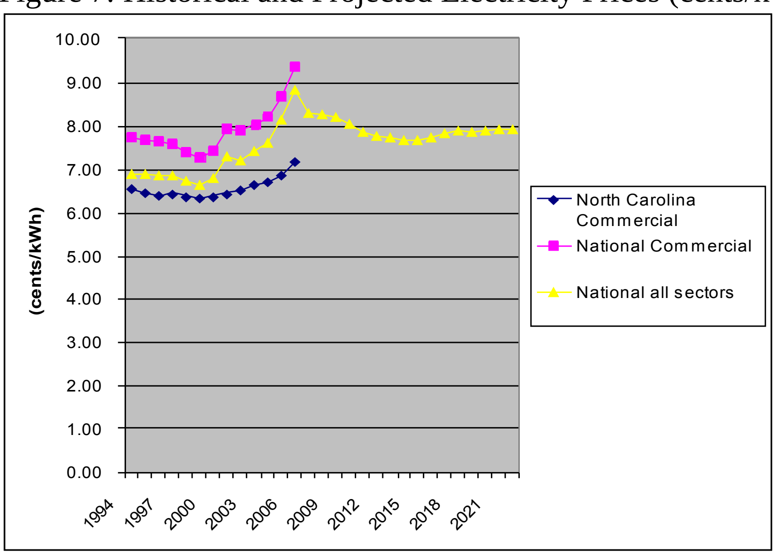
Figure 6: Historical and Projected Natural Gas Costs ($/MMBtu)



Source: Derived from EIA (2007b) and EIA (2007c) data.

The cost effectiveness of CHP is also influenced by electricity rates. Normally, as the price of electricity increases, the economics of CHP will improve. As Figure 7 indicates, commercial rates in North Carolina over the past two decades have been relatively low in comparison to the rest of the country. From 2000-2006, commercial sector rates for the state averaged under \$0.07/kWh, and over the last year, the cost of electricity in North Carolina for commercial customers has averaged \$0.0717/kWh, well under the national average of \$0.0936/kWh (EIA, 2007d). High natural gas prices will likely exert upward pressure on retail electricity prices in North Carolina, but coal prices over the long term are expected to remain low, on the order of \$1.70/MMBtu through 2030. Coal prices will likely help to keep retail electricity rates in North Carolina relatively low into the future, since most of the state's electricity is generated from coal (EIA, 2007c). On the other hand, electricity prices would probably increase significantly over the longer term if carbon emissions were regulated.

Figure 7: Historical and Projected Electricity Prices (cents/kWh)



Source: Derived from EIA (2007d) data.

Besides the price of fuel and electricity, the cost effectiveness of CHP is highly dependent on equipment costs and performance. CHP systems are by convention identified according to the prime mover, or engine, that drives the electricity generator. Prime movers in production today include steam turbines, gas turbines, microturbines, fuel cells, and reciprocating engines. Site energy requirements, market application, and the type of fuel utilized are among the parameters that dictate the type of prime mover that is employed (EAPC, 2001). While all of these technologies have achieved some degree of market penetration in the commercial sector, reciprocating engines are by far the most common prime mover for CHP, having been installed at 1,138 commercial sector facilities to date nationwide. These engines tend to be small in size, and at present, the average system size for facilities equipped with reciprocating engines is 858 KW; the median system size is only 150 kW. Over 450 of these facilities are equipped with systems less than 100 kW in capacity and nearly 800 commercial sites are running reciprocating engine CHP systems under 500 kW in capacity. The largest reciprocating engines in operation are on the order of several megawatts in capacity (EEA, 2007).

Cost and performance data for a variety of CHP systems amenable to the relatively small commercial users are presented in Table 1. Reciprocating engines currently have the lowest installed costs by a significant margin. Total installed costs ($/kW) generally decrease as the capacity of the reciprocating engine increases. Quoted installed costs include not only the cost of the equipment but also typical project and construction management fees, engineering fees, and labor costs. Equipment costs at present represent the largest share of the total installed cost. Also included in Table 1 are operating and maintenance costs. These costs include maintenance labor, engine parts and materials, and overhauls. The performance of the unit will also vary by system size, and electric efficiencies typically improve as the size of the unit increases. In a typical reciprocating engine, heat from the generation of electricity can be recovered from the engine’s exhaust gas, engine jacket cooling water, lube oil cooling water, and turbocharger cooling, and used for portable water heating and spacing, making it possible for these units to achieve overall energy efficiencies on the order of 70% and greater (EPA, 2007b; Energy Nexus Group, 2002).

Table 1: Cost and Performance, Small CHP Systems

Prime Mover	Capacity (kW)	Installation cost ($/kW)	Electric efficiency, %	Overall efficiency, %	O&M costs ($/kWh)
Recip engine	100	1708	29.7	78.3	0.018
Microturbine	100	2425	25.3	61.4	0.017
Fuel cell	150	5951	36	72	0.029
Recip engine	300	1378	31	77.3	0.013
Recip engine	800-1000	1323	32.5	68.8	0.009
Fuel cell	250	5511	43	65.1	0.032
Microturbine	250	2204	28.8	59.4	0.016

Source: EPA (2007b).

Taking all these variables into account, a limited number of studies have previously evaluated the economic potential for CHP for a select number of applications. A DOE (2002) study quantified the economic CHP potential at federal sites for six different building types. Assuming the full utilization of all recoverable waste heat and average 2000 energy prices, the study estimated the nation's economic CHP potential of these six building types to be on the order of 1,230 MW, with an estimated 17 MW of potential in North Carolina. For this study, only potential systems with a simple investment payback period under 10 years were considered economical. The marked increase in the price of natural gas since the publication of this study will have significantly reduced these estimates. Using the same screening criteria, another, more recent study (EEA, 2005) evaluated the economic viability of CHP at hotels. The assessment found that CHP would be an attractive investment for a large number of hotels across the country representing a combined 1,456 MW of capacity, with 5 MW of economic potential in North Carolina. The assessment further indicated that in North Carolina, CHP would only be a worthwhile investment for very large hotels (1,000+ rooms). Although a relatively recent study, energy prices have changed significantly since the time of its publication. For North Carolina, the economic viability of CHP was evaluated assuming a natural gas price of $6.46/MMBtu, now much lower than prevailing energy prices.

Another recent analysis (ERG & EEA, 2007) assessed the economic potential for CHP at wastewater treatment plants with anaerobic digesters. Anaerobic digestion generates biogas, which can be used as a fuel for CHP systems. The study concluded that anaerobic digestion at these facilities could produce enough biogas to generate between 225 MW and 340 MW in CHP systems. The recovered thermal energy could then be used to maintain digester heat loads and to displace natural gas purchased for a portion of the facility's thermal needs. According to the assessment, power could be generated at a net unit cost ranging from $0.001/kWh to just over $0.10/kWh, depending on the price of the CHP technology and the amount of fuel that is displaced. The study assumed an avoided fuel cost of $7.00/MMBtu, which for some regions of the country, including North Carolina, is likely on the low side. Recent increases in the price of natural gas will have worked to make such systems more attractive from an economic perspective due to their ability to displace the amount of fuel used elsewhere (e.g. for heating or hot water) on site.

III. Methods

In order to evaluate the likelihood of increased CHP market penetration in the commercial sector of North Carolina, net returns for the purchase of CHP units ranging in capacity from 100 kW to 1 MW were calculated. Net returns for each system size were defined to include the value of the electricity and usable thermal energy generated by the CHP unit, less capital costs, interest payments, the cost of fuel, and operating and maintenance expenditures. Other potential benefits of CHP, including emissions reductions, reduced transmission and distribution congestion, and improved power quality and reliability, which are much more difficult to quantify, were not considered in this evaluation. In addition, the assessment was conducted under the following assumptions:

(1) the CHP unit would be sized to meet the facility's average baseload electric demand;
(2) reciprocating engine CHP systems, as opposed to microturbines or fuel cells, would be the prime mover of choice for the facilities;
(3) the units would operate continuously except for any downtime due to repairs or maintenance, and;
(4) all electricity and useful thermal energy would be used on-site

It was assumed that the CHP unit would be sized to meet the facility's average baseload electric demand so as to make the findings of this assessment consistent with those from previous studies, namely OSEC (2000), which made the same assumption in quantifying the sector's technical CHP potential. Furthermore, although prime movers other than reciprocating engines, such as microturbines and fuel cells, would likely also be amenable to commercial market applications, such technologies are at present substantially more expensive than would be a reciprocating engine of comparable size, and will likely remain so for the foreseeable future. All net returns were also calculated under the assumption that the system would periodically go down for maintenance. Typical capacity factors for natural gas reciprocating engines were obtained from the EPA Combined Heat and Power Partnership and used in the calculation of the investment returns. For the systems under 800 kW in capacity, a capacity factor of 0.94 was used. For the larger systems, a capacity factor of 0.912 was assumed. These capacity factors reflect typical availabilities for natural gas reciprocating engines (Energy Nexus Group, 2002).

Benefits, which include the unit's electricity and thermal outputs, were calculated for each system size using performance data obtained from the EPA Combined Heat and Power Partnership for reciprocating engines commercially available in 2007, and summarized in Table 1 of the preceding section. The value of the electricity generated was determined by multiplying each system's electricity output by the average price of electricity for commercial customers in North Carolina as reported by the EIA. In 2006, retail electricity rates averaged $0.0717/kWh for the sector. The value of the usable thermal energy was calculated in a similar fashion, using average commercial gas rates for the state. Due to the recent volatility in natural gas prices, the value of the system's thermal energy was calculated and reported for two different sets of natural gas costs: 2006 prices, which averaged $13.45/MMBtu for commercial facilities, as well as 2000-2006 prices, which averaged just under $10.00/MMBtu.

Next, total CHP costs, defined to include (1) equipment and installation costs, (2) interest payments, (3) the cost of fuel, and (4) operating and maintenance-related expenditures, were determined as follows:

(1) Equipment and installation costs were obtained from the EPA Combined Heat and Power Partnership for reciprocating engines commercially available in 2007. These costs, summarized in Table 1 of the previous section of this report, include the cost of the equipment as well as engineering fees, construction management fees, and labor

costs.

(2) Interest payments were calculated assuming that a sum equal in value to the cost of the equipment and installation was borrowed at an annual interest rate of 6% and amortized over the lifetime of the equipment, typically 15 years for a reciprocating engine.

(3) Fuel costs for each system were assessed based on each engine's electrical efficiency and output using two sets of prices: average 2006 natural gas rates for commercial customers and average 2000-2006 rates ($13.45/MMBtu and $10.00/MMBtu, respectively).

(4) Operating and maintenance expenditures per kilowatt-hour of electrical output were obtained from the EPA Combined Heat and Power Partnership for each system size. These figures capture typical expenditures, per kilowatt-hour generated, for system maintenance, engine parts and materials, unit overhauls, and labor.

Finally, the net return of each CHP system was determined by subtracting total CHP costs (installation costs, fuel, operations and maintenance expenditures, interest payments) from the value of the system's outputs (electricity and the usable thermal energy). To make this analysis consistent with previous research, it was assumed that all of the electricity and waste heat generated would be used on-site.

In order to better understand the prospects for CHP in the state's commercial sector, a sensitivity analysis was conducted for each system size. Net returns were calculated in the same manner as described above, but for a set of natural gas prices ranging from $4.00/MMBtu to

$13.50/MMBtu. Electricity prices, which have historically been much less volatile, were held constant for the purposes of the analysis and in order to illustrate the relationship between the economics of a potential CHP project and natural gas prices. The sensitivity analysis helped to determine the level to which the price of natural gas would have to drop in order for each unit to "break-even," or for a net return of zero to be achieved. These prices were then compared to current and projected natural gas prices, shown in Figures 6 and 7 of the preceding section. Several additional sensitivity analyses were then conducted in the same manner, but assuming different electricity prices, in order to determine the effect of changing retail electricity rates on the economics of a CHP operation. Specifically, the break-even points (e.g. the price of natural gas yielding a net return of 0) for the following scenarios were calculated, with all prices relative to 2006 levels: (1) electricity prices decline by 5%; (2) electricity prices increase by 5%; (3) electricity prices increase by 10%, and (4) electricity prices increase by 20%.

So as to assess the sets of circumstances required for an economically feasible CHP operation, net returns were calculated for each state using the same framework that had previously been used for North Carolina. For this assessment, fuel costs as well as the value of electricity and heat produced by the system were determined using average 2006 commercial gas and electricity rates specific to each state, obtained from the EIA. The spark spreads of the ten states with the highest net returns were calculated and the policy (i.e. the offering of financial CHP incentives) environments of these states were characterized using the DSIRE database, which contains an up-to-date listing of any federal, state, or local CHP incentives, and is maintained by the North Carolina Solar Center at NC State. Existing commercial sector CHP as well as the technical potential for additional CHP were also evaluated for each of these states. The same assessment was then conducted for the ten states having the lowest net returns.

IV. Results

Installation and equipment costs, as well as the annual operating costs and fuel expenditures for reciprocating engine CHP systems up to 1000 kW in size and assumed to be operating in North Carolina's commercial sector, are tabulated in Table 2. Installation and equipment costs were seen ranging from $170,800 for the smallest system size, to over $1,300,000 for the1000 kW system. These expenses would be paid off over the lifetime of the units in annual payments and at an assumed interest rate of 6%. Annual payments amounted to $17,586 for the 100 kW unit; $42,564 for the 300 kW system; $108,976 for the 800 kW system; and $136,220 for the largest system. Annual operating costs for the systems ranged from nearly $15,000 for the 100 kW unit to over $70,000 for the largest system size, and would clearly constitute a significant expense for the potential CHP operation. Annual fuel expenditures, at over $125,000 for the smallest unit to well over $1,000,000 for the largest unit, tended to be comparable in magnitude to the one-time installation costs of these systems. To reiterate, the fuel expenditures in Table 2 were determined using the average price of natural gas for commercial sector facilities in North Carolina, $13.45/MMBtu. The total annual expenditures required to operate these units amounted to $159,790 for the smallest system size and $1,336,798 for the1000 kW system.

Also shown in Table 2 are the values of the electricity and usable thermal energy generated by each system. While these outputs are valuable, for none of the system sizes do they actually exceed the total annual costs required to operate the system given prevailing electricity and natural gas prices. Consequently, the net annual returns for all of the system sizes examined were negative to a significant degree.

Table 2: North Carolina: Annual returns ($) Given Prevailing Energy Prices

	100 KW	300 KW	800 KW	1000 KW
Installation and equipment cost	170,800	413,400	1,058,400	1,323,000
Operating cost	14,904	32,114	57,522	71,902
Gas cost	127,300	365,885	902,941	1,128,676
Value of electricity	59,040	177,121	458,256	572,820
Value of usable heat	61,867	169,405	325,962	407,452
Net annual return (including interest expense)	-38,882	-94,037	-285,221	-356,527

Note: Net returns calculated assuming average 2006 natural gas cost of $13.45/MMBtu and average 2006 electricity cost of 7.17 cents/kWh.

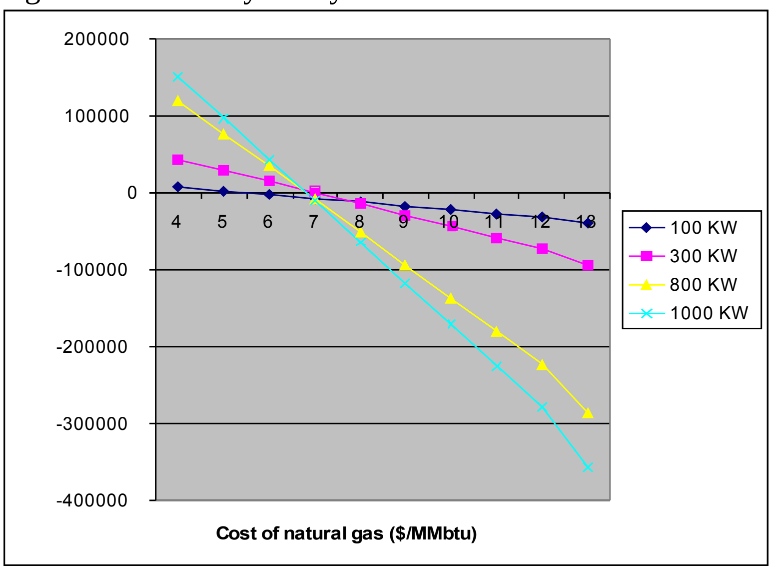
Table 3: North Carolina: Annual returns ($) Given 2000-2006 Average Gas Price

	100 KW	300 KW	800 KW	1000 KW
Installation and equipment cost, $	170,800	413,400	1,058,400	1,323,000
Operating cost, $	14,904	32,114	57,522	71,902
Gas cost, $	94,456	271,485	669,976	837,470
Value of electricity, $	59,040	177,121	458,256	572,820
Value of usable heat, $	45,906	125,697	241,861	302,327
Net annual return , $ (including interest expense)	-22,000	-43,344	-136,356	-170,446

Note: Net returns calculated assuming average 2000-2006 gas cost of $9.98/MMbtu and average 2006 electricity cost of 7.17 cents/kWh.

Table 3 shows net annual returns for the same range of system sizes in North Carolina, but assumes average 2000-2006 natural gas prices of only $9.98/MMBtu as opposed to prevailing costs. While the reduced natural gas prices do improve the economics of the potential systems notably, the net annual returns for all sizes are still well below zero. In fact, results of the sensitivity analysis, shown in Figure 8, indicate that natural gas prices in North Carolina would have to fall considerably from current levels in order for the economics of CHP in the state to become favorable. The returns for the systems tended to not break even until the price of natural gas dropped to the $6.80/MMBtu range. At this price, a net annual return of $3,128 would be achieved for the 300 kW system. For the 800 and 1000 kW units, net returns of $115 and $144 could be achieved, respectively, at gas costs of $6.80/MMBtu . At a price of $7.00/MMBtu, only the 300 kW unit could break even. The 100 kW system would not break even until the cost of natural gas dropped to about $5.00/MMBtu.

Figure 8: Sensitivity Analysis for North Carolina



Note: Net annual returns calculated for a 7.17 cents/kWh electricity cost.

Moreover, when assuming 2006 natural gas prices, electricity rates would have to increase to an average of $0.1170/kWh before most of the units achieved positive returns. Even when much lower 2000-2006 average natural gas prices are assumed, retail electricity rates would still have to increase to roughly $0.0940/kWh before the units' returns became positive. The results of the sensitivity analyses are summarized in Table 4.

Table 4: Summary of Sensitivity Analyses

Scenario	Break even
average 2006 electricity price	$6.80/MMBtu
↓ P_{elect} by 5%	$6.20/MMBtu
↑ P_{elect} by 5%	$7.30/MMBtu
↑ P_{elect} by 10%	$7.85/MMBtu
↑ P_{elect} by 20%	$8.90/MMBtu
average 2006 natural gas price	11.70 cents/kWh
average 2000-2006 natural gas price	9.40 cents/kWh

Only for a few states were the net annual returns consistently positive across all the system sizes examined. As illustrated in Figure 9, the economics of CHP were found to be quite attractive in several states, including Alaska, California, New York, Connecticut, Vermont, Massachusetts, Rhode Island, New Hampshire, New Jersey, and Texas. These states in general were found to have relatively high spark spreads due to their low natural gas costs and relatively high retail electricity rates (Table 5). For a number of these states, including Alaska, California, New York, and Connecticut, the net annual returns averaged across all system sizes exceeded $100,000. The ten states shown in Figure 9 have installed a combined 5,405 MW of CHP within their commercial sectors to date and were found to have the technical potential for over 25,000 MW of additional capacity (EEA, 2007; OSEC, 2000). Six out of 10 of the states, including New York, Connecticut, Vermont, New Jersey, Rhode Island, and New Hampshire, currently have financial incentives promoting CHP. In addition, seven of the 10 states have standardized the process of interconnecting the CHP system to the utility grid (DSIRE, 2007).

Figure 9: Highest Net Annual Returns by State, Prevailing Energy Prices

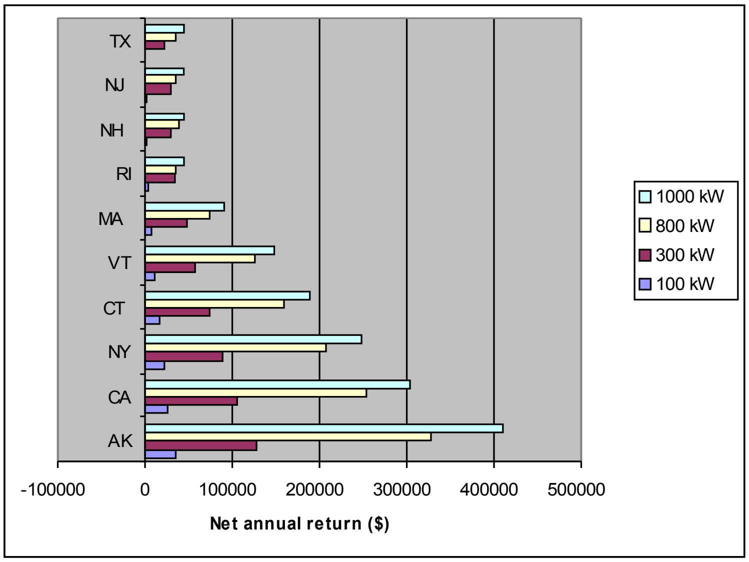


Table 5: Nation: Best Returns by State, Prevailing Energy Prices

State	Existing capacity (MW)	Technical potential (MW)	Spark spread ($/MMBtu)	Incentives	Standardized interconnection
AK	220	219	28.45728019		
CA	1,311	7,475	28.45182884		X
NY	2,008	6,092	28.09001172	X	X
CT	168	981	27.31410317	X	X
VT	2	179	23.49073857	X	X
MA	565	1711	25.50410317		X
NJ	265	2720	21.7710551	X	
TX	211	5829	18.71699883		X
NH	30	287	21.88998828	X	
RI	25	289	24.16485346	X	X

Source: Derived from DSIRE database (2007) and OSEC (2000).

States with lower spark spreads (i.e. high natural gas costs and low electricity rates) not surprisingly exhibited the lowest net returns. The net annual returns for Kansas, South Carolina, North Carolina, Virginia, Kentucky, West Virginia, Alabama, Missouri, Mississippi, and

Washington were among the lowest in the nation (Figure 10). Existing CHP across these states tended to be minimal and altogether totaled about 560 MW, as summarized in Table 6. The technical potential for additional commercial sector CHP for these states was found to be quite significant, however, totaling a combined 12,818 MW and exceeding 1,000 MW for six of the10 states (EEA, 2007; OSEC, 2000). Only three of the ten states, Washington, South Carolina, and Mississippi, were found to have financial incentives in place to promote CHP, while three of the states had standardized the interconnection process for distributed energy resources. These states included Washington, South Carolina, and North Carolina (DSIRE, 2007).

Figure 10: Lowest Annual Net Returns by State, Prevailing Energy Prices

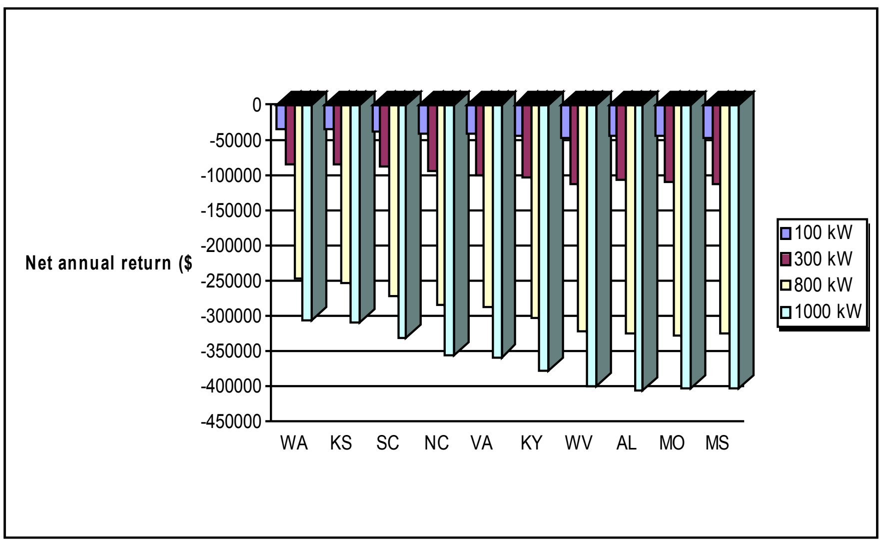


Table 6: Nation: Lowest Returns by State, Prevailing Energy Prices

State	Existing capacity (MW)	Technical potential (MW)	Spark spread ($/MMBtu)	Incentives	Standardized interconnection
WA	32	1640	7.586865894	X	X
KS	4	768	8.020788336		
SC	99	1194	8.331985434	X	X
NC	48	2408	7.561111155		X
VA	110	1858	6.065988522		
KY	0.8	901	6.159593309		
WV	72	424	4.354933891		
AL	3	1132	7.988467134		
MO	158	1639	5.162479218		
MS	33	854	4.060588474	X	

Source: Derived from DSIRE database (2007) and OSEC (2000).

V. Discussion

Despite its numerous advantages, the decision to adopt CHP is primarily a question of economics—whether or not the purchase of the unit will ultimately deliver an acceptable rate of return. Given prevailing and projected energy prices, CHP would clearly not be an attractive investment for most of the commercial facilities in North Carolina, at least for the foreseeable future. Assuming average 2006 natural gas and electricity prices, the 100 kW system would generate the best returns, nearly $-40,000 per year. When average 2000-2006 natural gas prices are assumed instead, the return improves to $-22,000 per year. Rates of return decreased significantly as the size of the unit increased, even though installation costs ($/kW) tend to decrease substantially with increasing system capacity. For the larger systems in the 800 kW to 1000 kW size range, returns averaged $-320,000 per year given 2006 natural gas and electricity rates. Even when 2000-2006 average natural gas prices were assumed, the returns for the larger 800 kW and 1000 kW systems still were on the order of $-150,000 on average. It is safe to assume that for most facilities, such returns would not be acceptable. The deployment of additional CHP in North Carolina's commercial sector is therefore unlikely, at least for the facilities with average electric demands below 1000 kW.

Average natural gas prices for the commercial sector would have to drop to around $6.80/MMBtu, well below the average 2006 price of $13.45/MMBtu and the 2000-2006 average price of just under $10.00/MMBtu, before CHP starts to become an attractive investment for most commercial sector facilities. Although the price of natural gas is anticipated to decline from current levels over the longer term, it is unlikely that commercial prices in North Carolina will drop as low as $6.80/MMBtu, at least for an extended period of time. With average natural gas prices of $13.45/MMBtu, retail electricity rates would have to increase to over $0.11/kWh before the returns would break even, well above current prices of $0.0717/kWh in the state.

The spark spread is not the only factor affecting the economics of CHP. Although a CHP system typically enables a facility to satisfy a significant portion of its energy requirements, interconnection with the utility grid in most instances is still be required for back-up or additional power needs. Utilities typically have their own sets of standards for the interconnection of CHP systems, intended to address concerns the utility has pertaining to grid safety and power reliability. Although justified to a certain extent, several recent studies (e.g. Hedman & Hampson, 2004; USCHPA, 2001; Alderfer et al., 2000; Brooks et al., 2006) have indicated that these standards often impose undue costs on CHP development in the form of expensive engineering and feasibility studies or the purchase and installation of certain types of equipment. In some cases, cogenerators have been required by the utility to purchase relatively expensive safety devices, even though equipment that provided the same level of protection was available for a significantly lower cost (Alderfer et al., 2000; Elliott et al., 2006). Such requirements would make the economics of CHP even less attractive by increasing the fixed costs associated with a potential operation.

The North Carolina Utilities Commission (NCUC) has addressed this issue to some degree by standardizing and simplifying the interconnection requirements of Progress Energy, Duke Energy, and Dominion North Carolina Power. These simplified standards, which have been in effect since 2005, apply only to distributed generators smaller than 100 kW in size and require a $250 application fee and that the commercial facility carry comprehensive general liability insurance with at least $300,000 of coverage. The standards also require the use of certain equipment, such as a redundant external disconnect switch, and prohibit the utilities from imposing indirect fees. The NCUC will soon have to establish interconnection standards for distributed generation systems up to 10 MW in capacity, as required by Senate Bill 3, which was enacted in August 2007 (DSIRE, 2007) It is hoped that such standards will make interconnection with the utility grid less of a barrier for potential cogenerators.

Utilities in North Carolina will typically require that facilities with CHP systems pay monthly "standby" tariffs. As an example, the standby charge for small customer generators in Duke Energy's North Carolina service territory is $1.03/kW per month. Since a facility with CHP will from time to time require additional power from the grid (for example, when the system must shut down for maintenance), a utility will have to maintain generation reserves sufficient in size to meet this supplemental demand while still ensuring adequate capacity to meet the needs of all its other customers. These fees are therefore justified insofar as they reflect, in theory, the cost of maintaining this additional capacity. By increasing an operation's fixed costs, however, these tariffs have the potential to make a potential project considerably less attractive. It has been argued by some (e.g. Elliott et al., 2006) that standby tariffs are "frequently set as though all CHP systems on a given utility system will fail at the same time, during a peak period, which is a highly unlikely scenario."   Elliot et al. (2006) also came to the conclusion that the "smaller systems do not impose costs that are any different from normal load variability with a given rate class." Whether justified or not, however, it is evident that these additional fees will affect the cost-effectiveness of potential CHP operations, and distributed generation in general.

Such disincentives to CHP and distributed generation in North Carolina are not all that surprising given the structure of the state's regulated electricity markets. When a utility's profit is determined by the amount of electricity sold, it will often be in the utility's best interest to oppose any form of on-site generation, or else see a decrease in sales and therefore profit (Hedman & Hampson, 2004). In addition, although deregulation has likely led to increased retail electricity prices in some states, electricity prices in North Carolina would have to increase to roughly $0.094/kWh, assuming average 2000-2006 natural gas prices, or to over $0.115/kWh, assuming average 2006 natural gas prices, before investment returns broke even for most of the system sizes examined. As Figure 7 suggests, it is unlikely that electricity prices in North Carolina will increase this substantially over the next decade or so, as coal prices are expected to remain sufficiently low over this period of time.

Some types of commercial facilities in North Carolina may still be able to benefit economically from CHP, however. A power outage of just one hour would cost a brokerage house several millions of dollars on average in lost revenue and other damages (Hedman & Hampson, 2004). Hospitals, telecommunications centers, credit card operations, and airline reservations centers also generally require an uninterruptible power supply. It has been suggested that a CHP system operating continuously could help to reduce the economic losses associated with grid outages (Hedman & Hampson, 2004). These sorts of facilities could therefore justify the purchase of a CHP unit, even given the state's low spark spread.

CHP may also prove an attractive investment for a facility that is capable of generating its own source of fuel. As an example, wastewater treatment facilities with anaerobic digesters can produce biogas that could be used to fuel a reciprocating engine CHP system. Since the anaerobic digester gas will have a lower energy content than that of natural gas, the engine would require some modification so as to accommodate this type of fuel. It is estimated that these modifications will increase the capital costs of a CHP system altogether by 15 to 25 percent. Operating and maintenance costs for a system designed to operate on biogas will also be on the order of 80% higher than for a standard reciprocating engine, due to increased wear and tear, more required cleaning, and the need for more frequent oil changes (RDC, 2004). A recent study (EEA & ERG, 2007) found that there are 17 different wastewater treatment facilities in North Carolina which operate at least one anaerobic digester and have total influent rates in excess of 5 million gallons per day. If used to fuel a CHP system, it is estimated that this biogas could generate over 4,500 kW of electricity throughout the state. For facilities such as wastewater treatment plants that are capable of generating their own fuels, CHP becomes increasingly cost-effective as the price of natural gas increases.

Solid biomass, such as crop residues and wood, could also provide a usable source of fuel for CHP. Although North Carolina has significant biomass reserves, estimated to be on the order of 11,000,000 tons, it is unlikely that most commercial facilities would find its use very cost effective due to transportation costs and the fact that the solid biomass would have to be gasified prior to its combustion in a reciprocating engine unit. Transportation costs would range from $30 to $35 per dry ton for the facilities relatively close to the biomass source and over $50 per dry ton for those farther away, or roughly $2.50 to $4.20 per MMBtu (RDC, 2004). With prevailing and projected prices of natural gas expected to be substantially higher, transportation costs alone would not pose a significant barrier to the use of biomass. The major hurdle to the use of biomass for fuel would be the purchase of a gasifier. With capital costs on the order of $1,000/kW, such systems could only be implemented cost-effectively at the largest facilities, typically industrial applications where the biomass is produced on-site (RDC, 2004).

A comparison of North Carolina and the other states having relatively low spark spreads with the several states whose average annual returns were in excess of $10,000 revealed some interesting differences. Of the ten states with the highest returns, six have financial incentives in place to promote CHP, including New York, Connecticut, Vermont, New Jersey, New Hampshire, and Rhode Island, and seven of the ten have standardized interconnection procedures. Some of the financial incentives designed to promote CHP are quite aggressive. California’s Self Generation Incentive Program offers rebates ranging from $1.00 to $4.50/Watt to facilities that generate electricity with reciprocating engines, while New York’s Enhanced Commercial Performance Program, recently established in February 2007, offers incentives of $1.50/therm of natural gas saved and $0.02 per kWh of electricity saved. In addition, Connecticut offers grants on the order of $450/kW to facilities that install distributed generation equipment. A number of these states also offer low interest loans and long term financing for the purchase of CHP equipment. California's Energy Efficiency Financing Program, for example, provides loans at a 3.95% fixed APR for schools, government facilities, and public hospitals. Half of these states, including California, Connecticut, New Jersey, New Hampshire, and Rhode Island have also set energy standards for public buildings which could help to encourage the adoption of CHP (DSIRE, 2007).

The states with the relatively low spark spreads and therefore low returns were less likely to offer financial incentives for CHP. Of the ten states with the lowest returns, only three, Washington, Mississippi, and South Carolina, are currently offering financial incentives for CHP. None of these incentives, however, seems particularly aggressive in promoting CHP. Both South Carolina and Mississippi offer low interest loans for potential CHP projects; South Carolina's ConserFund Loan Program will provide $25,000 to $500,000 low interest loans to non-profit organizations, public colleges, universities, and schools, as well as state agencies and local government facilities. Washington has enacted energy standards for public buildings with the ultimate goal of achieving a 10% reduction in energy purchases (DSIRE, 2007).

It would take huge financial incentives, in the form of rebates and long-term, low interest loans, to encourage the deployment of additional CHP in North Carolina's commercial sector. Assuming average 2006 natural gas prices, even if North Carolina, like California, were to offer cogenerators a rebate of $1 per Watt of installed capacity, as well as a low interest, long-term loan at a 4.00% fixed APR, net returns for all system sizes up to 1,000 kW would still be well below the point of breaking even, as illustrated in Table 7 below. Similarly, even if the state were to offer a rebate equal in magnitude to the equipment and installation costs of the potential system (e.g. $170,800 for the 100 kW unit, $413,400 for the 300 kW unit, and so on), average annual net returns for all the systems would still exceed $-100,000, assuming 2006 energy prices. If this subsidy were offered and the price of natural gas were to drop to average 2000-2006 levels, net returns would still remain negative. The spark spread is simply too low to justify the purchase of the equipment, even with these generous incentives in place. Even if all equipment and installation costs were fully reimbursed, it would take roughly an 8% increase in the price of electricity before the systems' average net returns broke significantly above zero, assuming 2000-2006 average natural gas prices.

Table 7: The Effect of Various Financial Incentives on CHP Economics

Incentive	Average Return
$1/Watt and low interest loan, 2006 natural gas prices	$-134,537
Equipment & installation costs reimbursed 2006 natural gas prices	$-117,330
Equipment & installation costs reimbursed, 2000-2006 natural gas prices	$-17,221
Equipment & installation costs reimbursed, 2000-2006 natural gas prices, Price of electricity increase to 7.7 cents/kWh	$6,196

VI. Conclusion

This report evaluated the economic potential for additional CHP in North Carolina's commercial sector. The attractiveness of CHP from an economic perspective will be significantly influenced by retail electricity rates, the price of natural gas, and the cost of the CHP equipment. With electricity prices expected to remain low and natural gas prices expected to remain relatively high as compared to historical levels, it is apparent that either (1) generous financial incentives would have to be offered to encourage the deployment of CHP or (2) equipment costs would have to fall significantly in order for CHP to become an economically sound investment for most commercial sector facilities in North Carolina. Over the longer term, two emerging technologies, microturbines and fuel cells, may help to improve the prospects for CHP in North Carolina's commercial sector. While these technologies would at present be substantially more expensive than a reciprocating engine system of comparable size, costs are expected to drop significantly in the future as production increases. Even given prevailing energy prices, certain types of facilities may find CHP an attractive investment. These facilities include those capable of producing their own fuel source, such as wastewater treatment plants, and those requiring an uninterrupted source of power. Although biomass reserves are significant in North Carolina, the cost of gasification currently presents a significant hurdle to its use at most, if not all, commercial facilities.

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