Challenges Facing Combined Heat and Power Today:
A State-by-State Assessment

Anna Chittum and Nate Kaufman

September 2011

Report Number IE111

529 14th Street, N.W., Suite 600, Washington, D.C. 20045
(202) 507-4000 phone, (202) 429-2248 fax, www.aceee.org

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EXECUTIVE SUMMARY

Background

For years, ACEEE has tracked which U.S. states have implemented policies designed to encourage greater deployment of combined heat and power (CHP). For the past four years this research has culminated in a dedicated CHP chapter in ACEEE's annual *State Energy Efficiency Scorecard*. However, CHP developers have noted that such an analysis does not always tell "the full story" when it comes to CHP. The CHP marketplace is affected not only by policies and regulations, but also by, among other factors, the business practices of utilities, the ideals of the local public service commission's, the market prices of different types of energy, and the availability of fuels for CHP systems. These types of issues are new areas of CHP research for ACEEE and are the focus of this report. The report attempts to capture the current status of the CHP market in each state, but does not attempt to address the longer-term need for additional technology research and development to make CHP more efficient, better performing, and lower cost.

CHP systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a technology, but an approach to applying technologies. Heat that would normally be wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. While the conventional, centralized method of producing usable heat and power separately has a typical combined efficiency of 45%, CHP systems can operate at levels as high as 80%. CHP confers many economic, environmental, and energy benefits to the facilities and localities that use it in place of more traditional power generation.

CHP is found across all sectors, but has historically served the industrial, large commercial and institutional sectors very well. Today it represents nearly 9% of the U.S.'s electric generating capacity. Federal agencies and CHP supporters widely agree that CHP could represent 20% of the U.S. electric generating capacity with the right policies in place. That substantial increase in CHP capacity could save the country 5.3 Quads of fuel—*almost half the total energy consumed by all U.S. households today*.

The history of CHP in the U.S. has been marked by important federal legislation. CHP received an important policy boost with the *Public Utilities Regulatory Policy Act of 1978*, which gave certain CHP facilities a guaranteed market for their power. This bill helped build a robust fleet of CHP systems across the country and marked the first time that federal legislation actively sought to encourage distributed generation and CHP.

The turn toward deregulation of the electricity sector in the 1990s, initiated by the *Energy Policy Act of 1992*, has been widely viewed as instrumental in the creation of barriers to CHP deployment in all sectors. Nonetheless, CHP faces economic, regulatory, and political barriers that have existed in the marketplace for some time, many at the state level. These barriers add significant costs and shape the types of CHP projects deployed in each state. Though some barriers can be overcome with good policy, other barriers are a reflection of the country's economic and financial realities, including the prices of electricity and natural gas (the favored fuel for CHP), which can heavily influence the economic viability of CHP systems.

Utilities interested in retaining their electric customer bases are generally not incentivized to support greater CHP, as new CHP projects would reduce customer demand. If they are to actively support the increased development of CHP in their service territories, electric utilities will require some external incentive or mechanism to recover the lost revenue associated with greater CHP deployment. Few utilities have these incentives or mechanisms in place.

In addition, few state energy offices and public service commissions prioritize CHP. CHP is often viewed by its advocates and supporters as a "homeless" suite of technologies in public policy. CHP is not well understood by regulators, not well-suited for renewable energy programs—because it often is powered by non-renewable fuels—and too expensive for most short-term energy efficiency programs—because its payback period is long and its upfront costs are high compared to many other efficiency measures. Consequently, few state administrations or lawmakers have taken up the cause of CHP, and in some areas of the country, there is almost no active support for CHP policies other than from one or two small not-for-profit organizations.

However, several states have developed policies and programs that support CHP, designing specific incentives or stipulating that CHP can count toward a portfolio standard or earn a healthy return on excess power. Moving CHP into the energy policy mainstream and maximizing its potential benefits to society requires the development of these kinds of policies at the state level and the removal of a multitude of barriers.

Due to the local nature of many of the barriers to CHP, the ability of the federal government to address them directly is limited. However, several important federal programs have made significant contributions to strengthening the CHP market. Most notable are the U.S. DOE Regional Clean Energy Application Centers and the federal CHP investment tax credit.

This Report

This report reflects conversations with over 50 individual CHP developers, supporters, state energy officials, public service commission employees, and managers of utility and public benefit efficiency programs (hereafter referred to collectively as “CHP developers and supporters”). These conversations were conducted over the course of 2010, primarily over the phone and with one or two individuals at a time. These primary sources hailed from across the country, from Alaska to Florida and most states in between. There were no standard questions asked of each individual. Instead, individuals were allowed to speak in an open-ended manner about their current perceptions of the CHP market in their states or regions. What these conversations yielded was a host of anecdotal and subjective information about the local CHP market as seen from the perspective of those most intimately familiar with it.

The collected findings from these conversations are presented in two sections: common findings applicable nationally—as they were noted by a preponderance of CHP developers and supporters across the country—and findings unique to a particular state or region. Economic barriers dominated these conversations, though the barriers themselves took slightly different shapes depending upon the area of the country with which a CHP developer or advocate was familiar. Finding a fair return on excess power—and having the ability to sell excess power—was another significant issue, also taking different shapes depending upon the region.

The second half of the report profiles individual states, highlighting the unique CHP environments of each. The more localized barriers identified included frustrations with particular utilities, interconnection challenges, problems accessing certain fuel sources, and other peculiarities of local or state laws or regulations. These more local barriers are noteworthy, as they tend to heavily influence the type and amount of projects developed in each state.

While ACEEE’s annual *State Energy Efficiency Scorecard* provides an assessment of which policies and regulations at the state level are viewed as favorable or unfavorable to CHP, and has scored states accordingly, some states show a weak correlation between strong policies and CHP deployment. The state profile section examines each state’s unique barriers, in some cases helping to shed light on why more CHP is not being developed, despite relatively good policies. Maine, for example, received four out of five points in the CHP chapter of ACEEE’s *Scorecard* but has seen only two new CHP installations in the past five years. This dearth of CHP development is in large part due to a lack of access to natural gas supplies in much of the state, as is detailed in the state’s profile page. Other somewhat “anomalous” states whose CHP environments are discussed in this report include Ohio, Indiana, Florida, Vermont, and North Carolina.

A key finding of this research is that, while there are some unique regulatory barriers in each state, CHP suffers generally from its high upfront cost, inexpensive and widely available electricity, and a lack of prioritization by regulators in all capacities. In addition, a clear market for excess power—and long-term expectation of such a market—would help enhance CHP deployment substantially. CHP developers feel that existing technologies can meet most current market needs, and that the opportunities for new CHP projects are significant. However, they still view certain projects as economically risky, and find that few areas of the country offer clearly favorable long-term economic and regulatory markets for CHP.

This report concludes with suggestions for how CHP stakeholders could further the development of the CHP market in the U.S. and individual states, building on existing successes. Though substantial progress has been made, the country has not realized the full economic potential for CHP. Doing so would bring substantial economic and environmental benefits to those facilities that use CHP as well as to society at large.

Acknowledgments

The authors thank, first and foremost, the CHP developers, supporters, state regulators, state energy office employees, and utility program managers who provided background information for this report for their candid descriptions of the current environment for CHP in their respective states and regions.

We thank the U.S. Department of Energy's Industrial Technologies Program for their support of this new research. This research built upon previous state-level research at ACEEE funded by the U.S. Environmental Protection Agency and U.S. Department of Energy. The authors would also like to thank Renee Nida for her careful editing of the final product and Neal Elliott for his help in developing the report's scope and focus.

Author Nate Kaufman, formerly of ACEEE, is now with OPOWER.

GLOSSARY

American Recovery and Reinvestment Act of 2009 (ARRA): Commonly referred to as the "stimulus" act, this piece of federal legislation dedicated substantial funds toward the research and deployment of energy efficiency and renewable energy technologies, including $156 million in funds for CHP and waste energy projects. This legislation also enhanced the offerings of several federal tax incentives relevant to CHP.

British Thermal Unit (BTU): A BTU is a unit of energy. It is, strictly speaking, the amount of heat necessary to raise the temperature of one pound of water by one degree Fahrenheit. In the world of CHP and electric generation, BTUs are used to represent the heat rate or conversion efficiency of given generators. For instance, a CHP unit might convert fuel to energy at a rate of 4,000 BTU/kWh. This would be a more efficient system than one with a heat rate of 5,000 BTU/kWh.

Combined Heat and Power (CHP): Also known as cogeneration, CHP is a method of simultaneously generating thermal energy (heat) and electricity (or mechanical energy) in a single, integrated system, often from a shared source of fuel.

Decatherm (DTH): A unit of energy frequently used in the natural gas industry. 1 DTH = 10 therms, or 1 million BTUs of energy.

Decoupling: The separation of a utility's profit from its sales of electricity as a commodity. Instead, a utility's revenue is met by setting a revenue target, then adjusting electricity rates to meet that target.

Demand-Side Management (DSM): DSM programs incentivize energy consumers to reduce their demand for energy at certain times in exchange for financial incentives or other benefits.

Deregulation: Electricity market deregulation allows a rate payer to choose other electricity providers over a local provider. These efforts can reduce or completely eliminate a local monopoly on electricity.

Distributed Generation (DG): Electric power generation located at or near the point of use.

Energy Efficiency Resource Standard (EERS): An Energy Efficiency Resource Standard (EERS) is a simple, market-based mechanism to encourage more efficient generation, transmission, and use of electricity and natural gas. An EERS consists of electric and/or gas energy savings targets for utilities, often with flexibility to achieve the target through a market-based trading system. All EERS's include end-user energy saving improvements that are aided and documented by utilities or other program operators. Often used in conjunction with a Renewable Portfolio Standard (RPS).

Federal Energy Regulation Commission (FERC): Federal agency that "regulates and oversees energy industries in the economic, environmental, and safety interests of the American public." (FERC Web site)

Heat Rate: The rate at which an energy generator converts heat (BTUs) to energy (kWh). The heat rate of a system is a measure of its inherent efficiency.

Independent System Operator (ISO): An ISO is tasked by FERC to monitor the electricity flows and coordinate activities of the local transmission grid. ISOs often act as a marketplace for power sales in deregulated markets. They typically cover a single state or region, such as the Midwest.

Interconnection and **Interconnection Standards**: For all distributed generation—solar, wind, CHP, fuel cells, etc.—interconnection with the local electric grid provides back-up power and an opportunity to sell or receive credit for excess power when such opportunities are available. It's important to most distributed generation projects to be interconnected with the grid, but adding small generators at spots along an electric grid can produce a number of safety concerns and other major headaches for a utility. Utilities, then, generally work with their state-level regulatory bodies to develop interconnection standards that clearly delineate the manner in which distributed generation systems may be interconnected.

Investor-Owned Utility (IOU): Also known as a private utility, IOU's are utilities owned by investors or shareholders. IOU's can be listed on public stock exchanges.

Kilowatt-hour (kWh): Basic unit of electrical energy; amount of energy consumed by 1 Watt for 1 hour = 3,412 Btu.

LEED: Leadership in Energy and Environmental Design is the preeminent green building rating system, developed by the U.S. Green Building Council (USGBC) in 1998. It provides a suite of standards for environmentally sustainable construction in both residential and commercial building sectors based on a scoring system comprising a set of required "prerequisites" and a variety of "credits" in six major categories. The six categories are siting, water use, energy use and local emissions, materials, indoor environmental quality, and design process.

Mcf: One thousand cubic feet. A volumetric unit of measure in the oil and gas industry for natural gas. 1 Mcf of natural gas is equal to approximately 1 Dth.

Net Metering: Net metering allows DG owners to receive credit for the energy generated by their distributed resources. A meter monitors the total outflows of energy (from the DG system) and the inflows of energy (from the grid) and thus calculates the "net" energy use/energy production from a system. In many states, DG owners can receive credit for generation when their DG meters are net positive.

Nonattainment Area: A designation required by the Clean Air Act and made by the U.S. Environmental Protection Agency (EPA). These are areas of the country where air pollution levels persistently exceed the National Ambient Air Quality Standards, which are set by the EPA.

Output-Based Emission Regulations: Air quality regulations that set pollutant limits based upon the useful output of a generator (in pounds of pollutant per kWh, for instance) are output-based emission regulations. More traditional regulations set pollutant limits based upon the input fuel burned in a generator to produce energy. CHP and other highly efficient equipment can produce more useful output from the same amount of fuel when compared to less efficient generators. Therefore, CHP benefits from output-based regulations, which that take into account the system's high levels of fuel efficiency.

PJM Interconnection: PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

Public Benefit Fund (PBF): A state fund dedicated to supporting and advancing energy efficiency and/or renewable energy projects. Funding comes generally from small charges on customer energy bills.

Public Utility District (PUD): A district created by a municipality, county, or other local governing body to provide electricity, waste removal, water, and other utility services. PUDs are typically governed by a commission, either elected or appointed by local government leaders.

Quad = quadrillion Btu = 1,000,000,000,000,000 Btu, about 1% of current U.S. total energy use on an annual basis; enough energy to heat about 22 million homes for one year or to power 15.7 million cars annually (driving an average of 14,000 miles per year at 27.5 miles per gallon).

Regional Greenhouse Gas Initiative (RGGI): RGGI is a cooperative effort by Northeastern and Mid-Atlantic states to reduce carbon dioxide emissions. To address this important environmental issue, the RGGI participating states will be developing a regional strategy for controlling emissions. Central to this initiative is the implementation of a multi-state cap-and-trade program with a market-based emissions trading system. Similar initiatives are set up in the Midwest through the Midwestern Greenhouse Gas Accord and in the West through the Western Climate Initiative.

Regional Transmission Organization (RTO): An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size.

Renewable Portfolio Standard (RPS): An RPS is a legally binding goal that requires that electricity suppliers within the included area use renewable energy resources to supply a certain portion of their electricity. RPSs are usually enacted on the state level and can sometimes include CHP or waste energy recovery as eligible renewable energy resources.

Spark Spread: Spark spread, as used in the CHP community, describes the difference between the cost of fuel needed to create heat and power onsite with CHP and the cost of purchased power from the grid to offset that same load if a CHP system were not in place.

Synchronous Generator: A synchronous generator is one that can generate power entirely on its own or in parallel with the local electric grid. Synchronous generators offer generator owners more flexibility in the operation of their system, but can present technical challenges when synching with the local grid. For this reason, synchronous generators can be more challenging to interconnect and sometimes must meet more requirements before being allowed to interconnect.

INTRODUCTION

Combined heat and power (CHP) offers many economic, environmental, and energy benefits to the individuals, companies, and localities that use it in place of more traditional power generation. CHP can be built quickly compared to central power plants and is more easily sited, thus quickly contributing to system reliability when increased capacity is urgently needed. Despite these benefits, considerable barriers to the greater deployment of CHP exist. These barriers are regulatory, economic, and political in nature, and vary significantly among U.S. states. Consequently, CHP deployment itself varies from state to state, and CHP project developers prioritize development in states with fewer barriers. Though some states have moved to eliminate some of these barriers, many barriers remain that inhibit greater CHP deployment across the country.

This report discusses the most significant current barriers to CHP deployment, primarily from the perspective of those most intimately familiar with the challenges of CHP development—the CHP project developers and supporters working to move a variety of CHP projects forward throughout the U.S. This report attempts to identify the greatest barriers to CHP project development today through personal conversations with developers and supporters from across the country.

This report profiles the current perceived environment for new CHP projects in all 50 U.S. states and the District of Columbia. It calls out the states in which the market for CHP project development is viewed as more favorable, and identifies the particular policies and programs that are being successfully used to move CHP projects forward in those states. The report also attempts to identify why particular states have not recently seen substantial CHP project development and, in some cases, suggests potential policy changes that might encourage greater CHP deployment.

Finally, this report discusses the role that state and federal policymakers could play in leveling and strengthening the playing field for CHP. The report suggests policy changes and improvements that should be made, in light of the current needs of the CHP developers and supporters consulted through this research.

Combined Heat and Power Today

Combined heat and power (CHP) systems generate electricity and useful thermal energy in a single, integrated system. Heat that is normally wasted in conventional power generation is recovered as useful energy, avoiding losses that would otherwise be incurred from the separate generation of heat and power. While the conventional method of producing usable heat and power separately has a typical combined efficiency of about 45%, CHP systems can operate at efficiency levels as high as 80%.

CHP has the potential to greatly reduce energy consumption, while also decreasing criteria pollutant emissions, increasing the competitiveness of businesses that use it, easing grid congestion, and enhancing reliability and ancillary electricity system benefits. Distributed energy resources such as CHP also provide economic development benefits, create jobs, and increase overall energy security.

The most substantial benefits from CHP are derived from the more efficient use of fuel inputs. A 2008 Oak Ridge National Laboratory report noted that more than *two-thirds* of the fuel used to generate power in the U.S. is lost as heat (ORNL 2008). Though that wasted fuel is never developed into useful power, it is still burned, producing superfluous emissions and wasting dollars. CHP systems can produce substantially more useful power by burning the same amount of fuel as conventional power generating systems—meaning that the more power that comes from CHP, the cleaner and more cost-effective it is. By operating the in-place CHP systems in the U.S. today alone, we are avoiding the consumption of 1.9 quads of fuel (ORNL 2008), which is more than the total annual renewable[1] energy production of the entire United States (EIA 2009).

[1] Not including hydropower and biomass-fueled renewable energy.

The 3,300 individual CHP sites throughout the U.S. represent almost 85 gigawatts (GW) of electricity, comprising 8.6% of U.S. electric generating capacity. If the CHP generating capacity were to reach 20% in the United States (an achievable goal), 5.3 Quads of fuel could be saved —*almost half the total energy consumed by all U.S. households today* (ORNL 2008). CHP can be used in all building sectors, and can be scaled to serve a single household's load (often called micro-CHP) or a large university campus' load, and every size load in between. CHP is not a specific technology, but an application of currently available technologies, and is typically composed of mechanical components manufactured in the United States.

A multitude of opportunities exist for CHP throughout the United States, and a great number of CHP project developers are working to install systems in all sectors of the economy. Unlike other alternative and renewable energy products and solutions, CHP is often—when presented with a level playing field—cost effective on its own, absent incentives or rebates of any kind. It generally uses established technologies that have been available to the marketplace for some time, and it has been proven to be an excellent fit for a wide variety of applications.

A Federal-Level Framework

Over the past several decades, states and federal agencies have, at various points, identified CHP as an important energy resource. CHP was given a critical federal policy boost with the adoption of the *Public Utility Regulatory Policy Act of 1978* (PURPA), which required regulated utilities to purchase power from qualifying CHP facilities (QFs). Utilities were required to buy this power at their avoided—marginal—cost, which guaranteed a reliable price for CHP-produced power (EIA 2000). This reliability, and the additional breakdown of in-place barriers to CHP afforded by PURPA, reduced the risk of investing in CHP systems. As a result, installed CHP capacity in the U.S. increased dramatically during the following years, growing 340% from 1980 to 1993 (Elliott and Spurr 1999).

While PURPA built a low-risk policy footing for CHP and largely insulated CHP projects from the vagaries of the energy marketplace, the *Energy Policy Act of 1992* (EPAct 1992) served to deregulate parts of the U.S. electricity market, introducing new market barriers to CHP. EPAct 1992 became law concurrent with a general trend towards electricity market deregulation across the U.S., opening access to transmission grids around the country and allowing a new type of generation resource—exempt wholesale generators (EWGs)—to compete for customers. These new generators were not necessarily CHP, and were not required to become "PURPA qualified." The influx of competition due to EPAct 1992 and the general deregulation of the industry lowered power prices, making PURPA QF contracts less attractive to generators. Without a PURPA QF contract, new CHP units faced barriers that had been rendered moot by PURPA and the development of CHP projects slowed considerably (Elliott et al. 2003).

The widespread deregulation of electric utility markets and the consequent open access to electricity transportation by utilities altered markets across the country. States stopped requiring utilities to provide contracts to developers of non-utility energy generation projects. PURPA has been amended considerably since its enactment, and now affects only a smattering of CHP projects around the country, usually those greater than 20 MW in capacity. The *Energy Policy Act of 2005* further codified the demise of the traditional PURPA QF in many markets by allowing the Federal Energy Regulatory Commission (FERC) to determine that particular regional markets are fully competitive, thus relieving certain utilities from the "must buy" requirement of PURPA (Stoel Rives 2006). FERC determined that such markets could be found, generally, in most of the areas served by either an independent system operator (ISO) or a regional transmission organization (RTO). In effect, this officially relieved utilities in the Northeastern quadrant of the U.S. from PURPA "must buy" requirements. Today, very few new CHP developments are QFs, and in general, in-place CHP projects that are QFs gained that status years ago. Non-QF CHP projects face a number of hurdles that, in today's deregulated market, are in large part the result of utilities protecting their assets and their profit margins in an effort to remain competitive and attractive to shareholders.

Recent federal legislation has helped reduce some of the hurdles facing CHP today. The *Energy Policy Act of 2005* was instrumental in encouraging state regulatory bodies to open dockets to consider interconnection and net metering standards that would encourage CHP and distributed generation generally. According to recent ACEEE research, as a result of Section 1254 of that legislation, 16 states adopted new or stronger interconnection standards for at least some form of CHP. In addition, the bill authorized the continued funding of the U.S. DOE Regional Clean Energy Application Centers (RACs), which have been instrumental in promoting CHP at the regional and state levels for almost a decade.

The *Emergency Economic Stabilization Act of 2008* established a 10% investment tax credit for CHP, which is set to expire in 2016. The tax credit is seen as an important step to improving the economics of CHP projects, though the full extent of its potential impact has not been seen, due to the economic downturn that has prevailed since its initial availability in 2008.

The *American Recovery and Reinvestment Act of 2009* provided more than $155 million dollars in grants to industrial energy efficiency projects, approximately $100 million of which was awarded to CHP and waste heat recovery projects. The industrial grants were oversubscribed by a factor of 25, with $10 billion worth of projects soliciting funds (DOE 2009). As noted later in this report, the funds from this grant opportunity have been moving slowly into the CHP market, and many CHP projects were not developed as a result of their grant applications being denied.

In spite of this legislation, CHP developers and supporters feel that the federal government lacks a coordinated CHP policy. While several federal departments and agencies run programs that support CHP, policies have been piecemeal and limited. In addition, since CHP typically burns fossil fuels and/or produces some emissions (albeit far less than typical centralized energy generation), CHP has not been as widely embraced by the alternative and renewable energy communities as other types of decentralized generation such as solar or wind. Thus, CHP is often referred to as a "homeless" energy resource, not as highly prioritized in energy policies as are other energy resources.

The ability of the federal government to address many of the regulatory barriers to CHP is inherently limited due to jurisdictional constraints. States and local authorities have jurisdiction over the implementation of many utility and environmental regulations, and a long legacy of judicial rulings limits the federal government's ability to compel regulatory changes by states.

The resulting variations in regulatory and market landscapes from state to state complicate the market for CHP. Developers wishing to operate in multiple states enjoy few economies of scale in their work, as each state presents a unique set of regulatory and policy barriers. Over the past several years, however, the establishment of a national technical standard for interconnection and the U.S. Environmental Protection Agency's issuance of guidance on output-based emissions regulations have helped to mitigate some of CHP's regulatory barriers (Molina et al. 2010).

Despite the important advances made over the past several years, many barriers still add cost, uncertainty, and delay to projects. Economic barriers, especially, hinder the deployment of CHP projects around the country. As discussed below, access to retail markets for excess power and freedom from restrictions as to where and how CHP projects can sell excess power would substantially change the economics of most CHP projects. Overcoming these economic barriers requires leadership at the state or federal level to change the policy landscape created by several decades of federal and state energy policies.

Leadership on the State Level

Absent national policies promoting CHP, some U.S. states have taken the lead in promoting it as an energy resource. As is discussed in this report's "State Profiles" section, some states that have actively sought to remove market hurdles have seen substantial growth in CHP project development. State lawmakers and regulators can be instrumental in establishing interconnection standards, tariff designs, environmental regulations, and other policy measures that can dramatically impact the attractiveness of CHP projects. State activity is essential in creating a market environment that encourages CHP. Over the past several years, an increasing number of states have worked to develop and implement "CHP-friendly" policies, while others have done little.

For more than a decade the American Council for an Energy-Efficient Economy (ACEEE) has studied market barriers to CHP and over the past three years has tracked which states have the most supportive and effective policies for CHP as part of the annual *State Energy Efficiency Scorecard* (Molina et al. 2010).[2] Many states have improved their rankings in the *Scorecard*, as more and more have adopted policies to support CHP.

State regulations, either enacted by a state legislature, a public utilities commission, or an executive agency, can address some of the above-mentioned barriers. These bodies can set time frames for utility procedures, prohibit certain utility practices, mandate certain actions for utilities, or outline guidance on emissions standards. Legislatures can also alter tax codes or provide financial incentives for certain types of projects. State-level public utility commissions have substantial say in the practices of IOUs operating within state lines. They determine, often to a greater degree than federal regulatory bodies, how utilities must treat proposals for CHP in their service territories and how utilities are or are not encouraged to deploy CHP in their service territories.

However, there are also limitations to what state policies can accomplish. State utility commissions have no authority over interstate electricity sales or wholesale electric markets—authority that is vested in the Federal Energy Regulatory Commission (FERC)—so developers of projects exceeding a certain capacity who wish to interconnect with the transmission grid are left to wrestle any interconnection barriers themselves.

Public utility commissions are also typically empowered to regulate only the IOUs in their state. Many states, particularly those with significant rural lands, see power distributed and sold by municipal or public utility districts and cooperatives, which are regulated by elected or appointed commissioners representing the service area. Some state and municipal laws are applicable to these utility districts, but such districts are usually exempt from the most impactful energy policy laws in each state. While some notable municipal utilities and cooperatives throughout the country employ progressive policies with regard to encouraging CHP and energy efficiency—due in large part to a more progressive customer base—most of these non-regulated utilities do little to promote clean energy or to actively seek to reduce barriers to CHP.

THIS REPORT

In response to ACEEE's annual *State Energy Efficiency Scorecard*, some CHP developers and supporters from around the country noted that, despite the presence of some CHP policies that are "good on paper", it is still very difficult to develop CHP projects in many of the highly ranked states. Additionally, the authors of this report heard anecdotal evidence that CHP projects were being developed without substantial setbacks in states that ranked lower in the *State Energy Efficiency Scorecard.* ACEEE concluded that the selected metrics used in the *Scorecard* were not capturing all the realities of the CHP marketplace in some states.

The *State Energy Efficiency Scorecard* considers whether or not the following policies are in place, and whether they are explicitly designed to apply to and encourage CHP:

- Interconnection standards
- Net metering policies
- Output-based emissions regulations
- Financial incentives
- A renewable portfolio standard or an energy efficiency resource standard
- Utility rates for standby power

[2] Visit aceee.org/research-report/e107 for the full results of the 2010 *Scorecard.*

The feedback from the *Scorecard* suggested that, even if a state had strong policies in place in the above categories, it could still be very difficult to move a CHP project forward. CHP developers and supporters noted several types of barriers that the *Scorecard* does not attempt to describe or analyze. These include but are not limited to:

- Low electric rates and resultant poor "spark spread" and project economics
- Utility business practices that stymie or stall CHP projects
- Lack of access to adequate financing
- Aversion to perceived risk and longer payback periods by potential host companies/facilities
- Lack of access to local markets for excess power
- Lack of technical knowledge or general awareness of CHP technologies and benefits
- Difficulty obtaining necessary permits

These barriers add to project cost and project risk. CHP projects require substantial capital investments, and in the current economic climate, additional risk and project cost can kill a CHP project that may have otherwise made good economic sense. Though CHP supporters exist in every state, and CHP projects make good economic sense in many applications, projects are far from ubiquitous. This disconnect appeared to warrant additional research.

Concurrent with the development of the 2009 *Scorecard*, ACEEE's CHP team began analyzing CHP project activity trends across the country using ICF International's CHP database. This database, funded by DOE, contains comprehensive information on CHP installations throughout the United States by operation year and by state. The database includes data on every CHP system installed, including location, capacity, fuel, prime mover, application, and the year in which it began operating. These data have provided a quantitative indication of how effective state policies have been in bolstering CHP markets.

ACEEE's analysis of CHP installation data reveals that the states ranked highest in ACEEE's *Scorecard* rankings for CHP-favorable policies tend to have a relatively high number of new installations and total installed capacity. Likewise, states ranked lowest in the *Scorecard* tend to have a lower number of new installations and little total installed capacity. However, there are some exceptions to this trend, and the spectrum between the highest-ranked states and the lowest-ranked states exhibits a very weak correlation between the ACEEE policy ranking and the installation data. With this in mind, along with an awareness of other limitations of the *Scorecard*, the authors saw a need for a state-by-state assessment of CHP markets.

Methodology

The goals of this research were to identify states viewed as most attractive to CHP project developers and states viewed as unattractive to developers, and why. To paint the most accurate picture of how friendly or unfriendly a particular state is toward new CHP projects, the authors sought the opinions of CHP developers and supporters throughout the country who are intimately familiar with the day-to-day challenges of moving forward new CHP projects.

"CHP developer" is a term loosely used throughout this report, but refers to individuals working to deploy CHP as turnkey project developers, equipment vendors, project owners, engineering firms, construction firms, third-party project financers, and general energy project developers. "CHP supporters" refers to individuals working to encourage CHP and employed by environmental organizations, state energy offices, federal energy agencies, utilities, research institutions, or state regulatory bodies.

CHP project developers that were actively involved in current or recent CHP projects were preferred, as were CHP supporters that were currently or recently engaged in policymaking. In all, over 50 CHP developers and supporters provided candid assessments of the CHP environment in their states and regions through telephone conversations and in-person discussions. Supporters and developers hailed from Alaska to Florida, and most states in between. Every region of the country was represented, and every state was represented by at least one individual. Many developers and supporters were familiar with the CHP markets in multiple states or regions.

Typically, these individuals easily identified the biggest hurdles to increased CHP development in their states. They identified utilities that are easy to work with, and those that are more difficult. They identified the policies that have been helpful to the bottom line of their projects, and those that look good on paper but actually do little to move a project forward. And they identified specific policies and regulations that have stalled or killed otherwise promising projects. This kind of on-the-ground knowledge is what seemed to be missing from previous assessments of CHP barriers, and is what the authors have sought to summarize in the remainder of this report.

PART I: GENERAL FINDINGS

This section will discuss findings that were identified by individual developers and supporters across multiple states. It will also discuss findings relevant to particular regions. These findings are separate and distinct from the state-by-state findings found in the *Part II: State Profiles* section of the report, begun on page 24. This section discusses policies, regulations, economic issues, and other barriers that affect CHP projects today.

Statements presented are not necessarily the opinions of the authors, but instead a reflection of the general opinion of those interviewed. Sentences or phrases within quotation marks are direct quotations from particular developers or supporters, and every attempt to convey the original context of the quotation has been made.

Economics

CHP projects are expensive, labor-intensive capital investments. Typical CHP projects come in all shapes and sizes, but with a reported initial average capital cost of anywhere from $700 to $3,000 per kW, they represent a large investment for any type of facility. These investments compete with other capital investments for priority and must generally be sold to company or facility decision-makers on their economic merits alone. It is the rare facility that installs CHP primarily for the environmental or other non-economic benefits. Furthermore, as will be discussed, potential future regulation of carbon dioxide has yet to strongly impact the CHP market. CHP projects are chosen over other heat and power options because they make good economic sense, even if the upfront cost can initially be staggering.

The good news is that CHP developers report that, in general, they currently have the technologies they need to implement most projects in the marketplace. While important opportunities continue to exist for improving the performance and cost of CHP equipment, especially for smaller systems, the immediate priority for many developers is to address other barriers to CHP deployment.

Past problems with equipment lead-time seem to have diminished. It appears that equipment manufacturers have developed lasting relationships with CHP developers, yielding better matches between the equipment supplied and the equipment demanded by customers. Some developers have also established lasting relationships with the manufacturers, helping developers understand which technical components work best together. This development has helped to usher in a new generation of CHP projects, wherein customers with multiple facilities have become familiar and comfortable with CHP and have identified it as a priority for other facilities around the country and world.

CHP equipment is, however, still very expensive, and the ratio of upfront capital cost to future energy and other cost savings is the greatest determinant of a project's viability. Our research identified economic challenges to be the greatest or second-greatest barrier to project implementation in every state. But economic barriers are not limited strictly to the high first cost of equipment or low forecasted future energy savings. Rather, many regulations and policies have a substantial impact on the economic returns of CHP projects. In general, these regulatory and policy barriers have made projects less economically attractive. Complicating this assessment, is the recent economic recession, which made borderline economic projects completely uneconomic and caused projects that would have been "no-brainers" several years ago to be dead on arrival. The following sections will discuss the most important factors impacting the economics of CHP projects today.

Market for Excess Power

Most CHP projects are sized to a facility's thermal load. By definition, this means that in most cases, there exists a mismatch between the facility's electric load and the system's electric output, since the project was not designed to meet a given electric base load. According to one developer, because of that mismatch, a CHP project seeking to maximize the return of the system's electric output is often thwarted to some degree, "confronted by the rules of the electric power industry," and tangled in franchise agreements, private wires laws, and high fees for sending excess power over privately owned distribution lines.

CHP developers around the country reported frustrations with limitations of where, when, and how they can sell the excess power from their systems. A common refrain among CHP developers was, "If we could get access to retail prices, we wouldn't need financial incentives." In most states, CHP projects are limited in how they can sell any excess power. While the most advantageous option is to sell excess power to another customer and charge retail rates, most states prevent CHP projects from doing just that. Typically this is because only regulated utilities may sell power to retail customers at retail rates. CHP projects are generally limited to selling their excess power back to the grid at a wholesale rate, which is far less economically beneficial. In some states, CHP projects can sell power to nearby facilities via private wires, at negotiated rates that may more closely resemble retail rates.

In general, CHP developers wish to be treated more as small independent distributed generators, able to sell power to whomever, than as passive elements of a utility's existing grid, able only to sell and buy power to and from the grid or to nearby facilities. CHP developers envision an ideal transmission and distribution grid that resembles today's federal highway system. Phrases like "level playing field" and "true free market" were often used to describe the ideal market structure in which a developer could sell excess power to anyone at a market-based rate. In fact, in most states, utilities own and manage the transmission and distribution infrastructure, and CHP developers must pay a regulated price for moving their excess power over a utility's private wires. For a CHP project to sell excess power to another retail customer at retail rates, that project would have to violate the regulations that protect the local utility's business model.

One developer offered this example:

> On average, a retail customer next door to me may be paying the utility 12 cents per kWh. I have excess power to sell. Even if I am located *right next to* a building that could use my extra power, I can't legally sell them my power. The only place I'm legally allowed to sell my power is to the grid, for 5 cents per kWh. So I do that, because I have excess power to sell. Ideally, I'd be allowed to strike a deal with my neighbor to sell my power. Maybe I charge 10 cents per kWh. I make some money, my neighbor saves some money, and we're both burning less fuel than we would be had we both just been buying our power from the utility.

While his experience is not representative of the situation in all states, it's a common one. CHP developers cited their inability to maximize their return on excess power as one of the top two specific economic barriers. Most developers identified it as the top issue that could be addressed by policies or regulations. Nearly a third of the CHP developers offered that taking down barriers associated with power export would completely change the economics of most CHP systems, dramatically altering the economic landscape. One developer in the Midwest said that a lack of good options for selling excess power "kills projects all the time."

Many developers cited a new rule in New Jersey that allows an entity to sell electricity to any facility to which it is also selling thermal energy services, even if that facility is located across a street or other public thoroughfare. Importantly, this rule also explicitly requires that such CHP systems be allowed to use existing electrical infrastructure to transport the power, and that the area utility only be allowed to charge a standard transportation tariff to provide the transportation service (New Jersey 2009). CHP supporters and developers in other states commented that they would be thrilled to have such a law in place in their states.

In Texas, where most of the electricity market has been effectively deregulated for nearly a decade, CHP developers are able to compete with larger centralized generators to sell power to a variety of end-use customers at market prices. Though a number of barriers remain to increased CHP deployment in Texas, developers report that the deregulated marketplace has been advantageous for CHP. The state now boasts the greatest amount (in MW) of CHP in the country (Cooney et al. 2008). To be sure, CHP's full potential in the state has not been reached, and Texas' industrial mix is particularly well-suited to CHP.

Spark Spread

The other most frequently cited barrier to CHP deployment was an unfavorable local spark spread. Spark spread—the difference between the cost of fuel required to power the CHP system and the cost of grid-provided heat and power to a facility had the CHP system *not* been installed—varies widely across the country and across sectors. Poor spark spread is one of the few barriers that policy and regulatory changes cannot directly address.

Spark spread is a product of external realities that extend far beyond the realm of CHP. The price of natural gas, which fuels well over half of the CHP installed since 1990, is set in the largely deregulated natural gas market (ORNL 2008). The price of grid-purchased power, which varies tremendously from state to state, is at least partially set by state utility regulators. In a regulated marketplace, the commodity price of power is set taking into account all the current capital and operating costs of each generation utility. In all markets, regulators set the delivery charge for power taking into account the cost of delivery infrastructure. Most of the states in which spark spread was cited as the primary barrier to CHP development have notably low electricity prices. Throughout the Southeast, parts of the Midwest and Great Plains, and into the Northwest, cheap power serves to imbalance the economics of potential CHP projects. While a poor spark spread cannot be "fixed" with policies and regulations, it can be somewhat mitigated by policies and regulations that favorably alter the economics of CHP projects.

Making the economics work for a CHP system can be very challenging in states with an unfavorable spark spread, as is noted in some of the following state profiles. One stakeholder said that she sometimes works through a scenario with a prospective CHP developer during which she asks, "If you were given this system for free, would it be economic to run it?" Too often, she said, the answer is no. In her state of Oregon, which boasts some of the cheapest electric rates in the country, the cost of fuel alone could be enough to make the project uneconomic to build and run.

Spark spread can be impacted by the overall and specific electric efficiency of the CHP equipment itself, so CHP developers facing poor spark spreads often find themselves asking, "How can I close the spark spread with a better heat rate?" More efficient equipment will only go so far, however, and highly efficient CHP equipment cannot overcome a very poor spark spread. In some states, industrial electric rates are as low as three or four cents per kWh. Such rates would make most CHP projects appear uneconomic from a strict payback analysis standpoint, even if substantial incentives were available. However, payback analysis, as discussed below, does not always paint the most accurate picture of CHP project economics.

Payback, Risk, and the Recession

Simple economic payback for a CHP project is the length of time required for the annual project savings to equal the initial capital investment. Though economic payback is a very simplistic measure of a project's value to a company or facility, it remains a common metric used by facility managers and other decision-makers. Payback period is used as a "first cut" benchmark, and decision-makers have a desired payback period in mind when prioritizing new capital investments. Projects that do not immediately appear to offer a payback within the desired period are generally not considered. This is especially true in the current economic climate.

Stakeholders reported calculated payback periods on today's *potential* CHP projects as ranging from 1.5 to 12 years, with 4 to 6 years representing the most typical range. This means CHP projects are currently non-starters for most facility managers or other decision-makers, who are only comfortable with projects with very short payback periods, most frequently 6 months. CHP developers and supporters said that all investments with energy efficiency as the primary investment driver must come in at a payback of less than 1 year to even be considered by most facilities in the current economic climate. However, they also reported that in cases where energy efficiency investments or CHP projects help meet other, more pressing essential business needs—such as relieving thermal capacity constraints or production shortages—investments with longer paybacks have occurred. But this has been the case *only* when some other business need is the primary investment driver.

The aversion to longer payback projects has had a tremendous dampening effect on CHP project development, particularly in the industrial sector, according to developers. While several years ago, a CHP project boasting a 4-year payback might be viewed as attractive, today it is viewed as too risky by many private firms, and a "non-essential" investment for a company loath to invest in anything that will tie up capital for more than 6 months. Institutional customers, such as educational and healthcare, can accept longer payback periods, as they take more long-term approaches to their capital budgeting processes.

In the industrial sector, where the current desired payback for energy efficiency investments may be 1 year or less, CHP competes for attention from facility managers with other, more immediately cost-effective energy efficiency projects. CHP supporters and developers report that even energy efficiency investments boasting payback periods of far less than 1 year are not currently being made in the industrial sector. They say also that the most substantial energy efficiency investments at the moment are being made by companies with a strong environmental focus.

The current economic downturn has caused companies and institutions to become very conservative with their cash and wary of unnecessary risk. Taking on projects that will not return their initial investment within five years can feel risky to a company that is not sure it will be able to employ the same number of staff a year from now. Compounding the actual risk of some CHP projects is the perceived risk that may or may not be grounded in fact. CHP developers report that a number of potential clients still believe that the price of natural gas is highly volatile, despite its 20-month plateau (EIA 2010a). When a piece of equipment like a boiler needs to be replaced, investing in a new type of technology can feel riskier than investing in the same type of equipment already being used.

The current economic downturn exacerbates what was already a challenge for CHP developers. They argue that the "boiler vs. CHP" comparison is not the right one to be making. They believe simple payback is not a sufficient methodology to determine whether a CHP project should be considered. Comparing payback of a boiler to a new CHP system ignores all the additional costs that a CHP system helps avoid: the cost of doing nothing, or "business as usual" heating and cooling costs; the societal costs of using less efficient centralized energy generation; and process heat needs and other costs that might be eliminated by harnessing the byproducts of the CHP system.

Multiple CHP developers said they believed that facility owners do not know what their business as usual costs would be, or how to make a more nuanced payback calculation, which would include all avoided costs. In this case, it appears that the CHP developers themselves must lead the effort to educate facility managers and company owners and help them make these calculations. CHP developers report that making this kind of argument, and asking facilities to think beyond typical payback period, is easier when working with new construction projects. Since the developer and host are already thinking about the long-term costs and benefits of certain materials and equipment, it is easier to make them aware of the full benefits of a CHP system.

Prior to the economic recession, projects with 3- to 5-year payback periods were easily developed. CHP developers should be prepared to help harness the momentum of a future economic recovery by teaching facility managers, owners, and policymakers how to calculate the true, long-term benefits of CHP. Right now, "There's not much we can do if a customer is short of cash," said one developer. Even if a project makes great sense, many companies simply lack the capital to develop it. In the interim, a project developer or equipment manufacturer may be able to help reduce a facility's operating costs and advance a CHP project regardless of a shortage in cash by installing a system, financing it with external partners or with internal funds, and owning the system itself. Such creative project structures may be required to move CHP forward in the current environment.

Financing

Encouraging internal decision-makers to consider CHP is difficult. But developers report that even after the decision is made to invest in CHP, many of the typical financing avenues have dried up. "A typical banker doesn't really understand CHP," noted one stakeholder. Unknowns are tantamount to risk in the financial world and a CHP project presents many unknowns. Though the financial sector is well known for complex financial products, CHP is a wholly different type of venture to most investors. This could help explain why CHP developers have such difficulty selling CHP projects as smart investments to external investment partners.

Developers report that finding the right investment bank or equity firm can be a challenge, and sometimes a fruitless pursuit. CHP projects themselves are often too small to pique the interest of these types of investors. Consider a 20 MW (mid-sized) CHP project, with total costs amounting to $30 million. A project developer looking to secure a typical 30% equity stake from an outside investor would be looking for a $10 million investment, which is too small to entice larger investment funds and to warrant the attendant transaction costs. As one developer said, an equity firm "won't even touch" a project under $5 million and $10 million is a hard sell for most. Giving up a larger portion of a project to an outside equity firm—90% in one developer's case—was one way to further entice investment. But CHP host sites may not wish to give up an equity stake.

One innovative way some project developers are working to overcome the size barrier is by packaging small projects together and presenting them as one single investment. This reduces transaction costs and makes the project package more likely to fit within an investor's size target. Though such examples are few and far between—partly because of the difficulty of finding enough projects at the same stage of development to aggregate into one package—there is a growing awareness among CHP developers that such creative approaches will be required in order to appeal to more mainstream investors.

CHP developers do not always have to seek investment funds, however. Many other financing options are available. Debt financing, which is usually less expensive than equity financing, is an attractive option for companies with good credit. Many industrial companies enjoy superb lines of credit, and when they choose to invest in CHP they tend to self-finance as much as possible. But even those companies are deterred at the moment by the high cost of CHP equipment. With business revenues stagnating or stalled completely, tying up cash in a new CHP project—even when the cost of capital is very low—is seen as a poor business decision at the moment, according to CHP supporters.

Financing has become less of an issue generally for institutions such as hospitals and universities, where a number of projects mentioned by CHP developers and supporters were financed largely with low-cost bonds or internal capital. Certain sectors always have less difficulty securing financing, and the institutional sector is one of them. In Oklahoma, where a new 15 MW project at the University of Oklahoma is providing power and steam to the campus, the Board of Regents of the university approved funding to completely cover the project with internal funds.

Though there are a few bright spots in current CHP project development, more than one developer says capital constraints have been big. The economic downturn has exacerbated these constraints and made all parties—developers, investors, financers, and facility owners—more uncomfortable with risk and long payback periods than in the years prior to the recession. Today, these parties look at how dependent a CHP system's payback is on fuel prices and variable electric rates, and conclude that it does not make sense to invest, as the "unknowns" are too big to present a clear financial return. As discussed later in this report, no amount of financial incentives or stimulus funds will change the fact that CHP is, given existing regulatory and economic barriers, not attractive to a great number of investors in the current economic climate. The hope is that companies sitting on cash today will be ready and willing to invest in new capital projects once the economy begins to recover.

Regional and Sectoral Differences

Economic barriers to CHP projects are exacerbated and mitigated to differing degrees, depending upon which area of the country the CHP project is to be located. The economic sector in which a CHP system is being considered also impacts how economically attractive it appears.

There are economic realities of each region that make CHP systems more or less attractive. Spark spreads, discussed earlier in this report, impact a project tremendously, and vary considerably from region to region. So too do specific policies designed to encourage CHP—many of which will be discussed in the next section of the report. Though spark spreads and policies vary among states and even among utility territories, some generalizations can be made about certain regions of the U.S.:

- The **Southeastern** U.S. has consistently poor spark spreads. The Southeast enjoys below-average electric rates and average natural gas prices (EIA 2010a). A lot of Southeastern areas boast industrial loads that would be suitable applications for CHP, but payback appears to be too long to entice most facility owners. The Southeastern states historically score very low in ACEEE's annual *Scorecard*, indicating that the states in general lack substantive policies to encourage energy efficiency, including CHP. North Carolina is the exception to this rule. Anecdotally, it is also apparent that certain utilities in the Southeast, including Entergy and Southern Company, are viewed by CHP project developers as particularly unfavorable to CHP.

- The **Midwestern** U.S. also has generally poor spark spreads. It relies heavily on cheaper coal-fired power plants for its power, and has average electric rates and natural gas prices. The Midwest, too, has substantial industrial loads. Ohio is second only to Texas in total industrial retail electricity sales, and is joined by Indiana, Illinois, and Michigan in the top ten (EIA 2010b). Those same four Midwest states also rank in the top eleven states with the highest industrial energy consumption (EIA 2010d). Midwest states generally score in the middle of ACEEE's *Scorecard*, although the Midwestern Governors Association has identified CHP as an important energy efficiency and job creation tool for the region. In addition, two states—Ohio and Illinois—have ranked particularly high in the CHP policy category (Molina et al. 2010). However, a general consensus among CHP developers in the Midwest is that the region has been particularly hard hit by the economic recession, and potential hosts are therefore very hesitant to invest in new capital projects at the moment.

- The **Mid-Atlantic** U.S. has been viewed recently as a growing market for new CHP projects, thanks in large part to the easing of unfavorable regulations in the area, high electricity prices, and significant grid congestion issues (EIA 2010a). These states have recently received high ranks in ACEEE's *Scorecard*, and have benefited from their inclusion in the PJM Interconnection, the regional transmission organization that led an interconnection working group to define uniform interconnection standards for generators within the PJM "footprint." These standards are used in lieu of other utility-based standards in many of the utilities in the PJM region, and are viewed as favorable to CHP systems by developers and supporters (PJM 2009). Additionally, the Marcellus natural gas shale discovery, if proven to be as large as anticipated, may well stabilize natural gas prices in the region for years.

- The **Northeastern** U.S. has traditionally been viewed as a more amenable market for CHP, due to more favorable spark spreads, more aggressive energy policies, and more progressive energy utilities. The Northeast has some of the highest electricity rates in the country, and certain states, such as New York and New Jersey, have very high commercial energy loads, which lend themselves well to CHP (EIA 2010a, 2010b). The Northeastern states have historically ranked very high in ACEEE's *Scorecard*, and very high in the CHP policy category as well (Molina et al. 2010). The Northeast was also the first region of the U.S. to initiate a cap-and-trade mechanism for greenhouse gases with the Regional Greenhouse Gas Initiative (RGGI). RGGI goals as well as transmission and distribution constraints in the region have helped move Northeastern regulatory bodies and utilities towards more aggressive energy efficiency goals, further benefiting the CHP market.

- The **Northwestern** U.S. has been viewed by many in the CHP community as a neutral to negative ground for CHP. While some policies exist to support CHP, the economics are often quite unfavorable. An abundance of hydropower has created poor spark spreads in the area, as the Northwest enjoys the cheapest electricity rates in the country (EIA 2010a). Washington and Oregon have scored well in the CHP category of ACEEE's *Scorecard*, while Montana and Idaho have consistently scored below average (Molina et al. 2010). The Northwest does not have a particularly large industrial load, but it does have a large forest products industry. Wood, wood waste, and other biomass products fuel the vast majority of CHP projects in the region (ICF 2010).

- The **Southwestern** U.S. has historically not been viewed by many CHP developers and supporters as a strong CHP market, due in large part to its average electricity prices and a lack of grid congestion challenges that, in other areas, serve to encourage CHP (EIA 2010a). California, as discussed in its *State Profile* on page 30, has been an exception to this rule. The Southwest has average industrial loads, average natural gas prices, and average ratings for its CHP policies in ACEEE's *Scorecard* (Molina et al. 2010). It does not, however, have much need for heating in many of its sectors, and thus the demand for CHP systems is low, according to CHP developers and supporters who work in the area.

- The **Gulf Coast** region is an active CHP market. Texas and Louisiana alone contain over 25% of all CHP capacity in the U.S. (ORNL 2008). This is due in large part to the energy requirements of the large petrochemical industry in the area. In Texas, where the electricity market is mostly deregulated, CHP projects can sell their power to a wide variety of end-use customers, competing with more traditional generators in the process. While Texas has ranked highly in the CHP chapter of ACEEE's *Scorecard,* Louisiana has traditionally ranked very low. In this case, the business case for CHP has historically been strong enough to overcome some substantial regulatory barriers, but developers report that many projects today remain "on the drawing board" in that state.

Differences across regions impact the attractiveness of CHP projects. So, too, do differences across sectors of the economy. As mentioned earlier, applications with longer time horizons, such as hospitals and other large institutions, are more willing to take on the long-term economic payback of a CHP system. Developers noted that the healthcare industry has seen a significant increase in CHP development lately. In part this is due to the increased digitization of the health care industry, requiring that more and more equipment and record-keeping computers be available 24 hours a day. These systems require redundancy, and CHP can offer that as well as day-to-day operational savings.

Other fuels beyond natural gas represent a growing segment of the CHP market, according to developers. A surplus of certain types of fuel—such as beetle-kill wood in the Mountain West—is being identified as states work to satisfy their internal goals for renewable energy production. "We are trying to figure out how to access and utilize fuels that are present and cheap," explained one developer from the region. Animal waste, particularly at food processing plants throughout the Southwest and Midwest, is being seen as another long-term fuel opportunity for CHP projects located in close proximity to animal operations.

Beyond those few facilities with an abundant and cheap local fuel supply, the private sector is not currently being viewed by developers as a prime target for CHP installations. Public sector buildings, which are increasingly subject to energy or greenhouse gas reduction goals and mandates, are attractive to many developers around the country. In feedback for this report, CHP developers mentioned a number of CHP projects that had recently been killed or delayed. They were almost always projects in the private sector, and public sector projects represented the few bright spots on CHP developers' horizons.

Incentives

A number of states offer financial incentives in the form of grants, bonds, rebates, tax credits, and loans for developers or owners to install new CHP systems or retrofit existing systems with CHP. Financial incentives on both the state and federal levels have, in many cases, effectively led to increased installations. Among the developers and supporters that provided background for this report, there appeared a wide range of opinions regarding which incentives are best, and how they are best used to encourage CHP and help CHP projects overcome barriers. This section will not attempt to describe all the different types of incentives or the merits and drawbacks of each. It will, however, describe some of the types of incentives greatly impacting the CHP market today, and discuss how they are being used.

Financial incentives for CHP can be viewed in two ways: 1) they can be used to make the economics of a project more favorable, increasing the likelihood of the project's execution; or 2) they can be used to mitigate the existing regulatory barriers—to defray the costs of interconnection studies and fees, compliance with emissions standards, and other fees and procedures. The removal of regulatory barriers can therefore inherently enhance the economics of a project, and perhaps in some cases obviate the need for financial incentives. However, in many cases, incentives are still needed for making CHP reasonably cost-effective. In states with unfavorable spark spreads, even if all unnecessary regulatory barriers were removed, incentives could still play a critical role in making CHP projects economically attractive to achieve a state's environmental and energy goals. Most developers noted that the path to market transformation for CHP is a combination of good regulation, coordinated financial incentives, and sufficient education and marketing.

Tax Credits and Feed-In-Tariffs

The state-level incentives that CHP developers and supporters most frequently cited as helpful were investment tax credits and production credits. One particular tax credit, a 35% renewable energy tax credit in North Carolina, is already garnering substantial interest among CHP developers, as the credit was expanded to include CHP in 2010. Tax credits were noted to be very useful to third-party investors and others investing in CHP systems because they are a reliable source of savings and can easily be worked into a pro forma statement or other forward-looking business plan. "With a tax credit, you're assured that it's there," said one developer. "With other types of incentives, you don't get that guarantee."

Of course, to take advantage of tax credits, an entity must have some tax liability. Some businesses, having already taken advantage of numerous tax credits offered by local economic development entities, find themselves with little remaining tax liability. In these cases, tax credits for energy improvements have not been as instrumental in moving CHP projects forward. Tax credits are also not useful to tax-exempt nonprofit institutions, including universities and hospitals, which have no business tax liabilities. In these kinds of situations, partnering with third parties can help create business entities that can take advantage of tax incentives. Production credits, such as New York's per-kWh Existing Facilities Program, were highly regarded by developers and were also viewed as a very reliable source of savings. Developers in New York cited such credits as critical in making New York's CHP market one of the most attractive in the nation.

As noted in the previous section, the federal government provides an investment tax credit—a 10% credit against business taxes—that is viewed by developers and CHP supporters as important, but not a "game changer." The federal tax incentive does not leverage additional money the way upfront payments, loans, or grants do, according to some developers. This argument can be made about all tax incentives, as the developer or system owner still has to acquire the upfront cash outlay for the project, and then earn the tax credit on future business taxes. The federal tax credit was expanded and enhanced by 2009 federal stimulus legislation, as discussed below, but these improvements are time-limited. After 2010 they will diminish greatly (ARRA 2009).

The other type of guaranteed incentive developers were keen to discuss was a feed-in-tariff (FIT). A FIT is a long-term contract a generator may enter into with a utility to have the generator's power purchased at a set rate. Like a production credit, a FIT pays a CHP system a set amount per kWh produced. However, unlike a production credit, a FIT locks in a rate for years; giving a CHP developer substantial assurance that the CHP project will earn a certain premium on produced power over the years. FITs have long been used in European countries to encourage mid-sized CHP systems, but have not historically been used in the U.S. Today, only California has attempted to establish a true FIT, and only the Sacramento Municipal Utility District (SMUD) has developed a FIT specifically for CHP. The SMUD program was very popular and is now closed to new contracts due to oversubscription (SMUD 2010). Developers indicated that anticipation for new FITs is very high, and that mainstream use of FITs as policy tools would dramatically strengthen the entire U.S. CHP marketplace.

Loans and Loan Guarantees

Loans and loan guarantees are a popular offering at the state level to encourage CHP and other renewable energy and energy efficiency investments. CHP developers universally agreed that loan guarantees are "almost as good" as loans themselves, in the words of one developer. "It's the perfect thing for an economic development entity to do," noted another. States tend to favor offering loans because there is relatively little cost to the government in lost revenue as tax incentives, and it is easy to partner with existing banks and development authorities to issue the loans or loan guarantees. Though loans and loan guarantees are never enough to move a CHP project forward that would not have otherwise been a success, they are seen by developers as very useful, particularly in the current economic climate, when financing can be hard to secure. States also favor loans because most of the CHP projects that apply for loans are sound projects. Several state program officers noted that the risk of default is very low, as the projects have usually been well vetted by the time they seek a loan.

One idea expressed by several CHP developers was to develop loan programs with very long time horizons. A typical energy efficiency loan program has a 10-year repayment period and a project cap of well under $100,000. CHP developers were interested in programs with longer repayment periods and larger project caps. Loan programs are prevalent, but are often limited in their maximum loan amount. As noted before, CHP projects can be very expensive, and a local loan program will typically not be big enough to make a significant impact on a CHP system.

Net Metering

CHP systems are rarely able to take advantage of net metering policies, which allow CHP owners to receive credit against their electricity bills for the electricity generated by a CHP unit and delivered to the grid. This is most often due to limitations on project size or project technology embedded in the net metering regulatory language. Currently, 16 states and the District of Columbia have net metering policies in place for some form of CHP. Subtle differences exist among states, such as whether credits can be carried over from month to month. Actually having net metering policies in place is more important than the details of the policy, developers say, because a net metering standard provides an avenue to officially approach a utility, and compels utilities to develop interconnection standards for net metered energy resources.

Net metering "makes things easier," according to some developers, but is typically only applicable to small or renewable-powered CHP units. Such policies can make a difference for smaller systems, but will not, by themselves, make a borderline CHP project economic.

Grants

The most widely noted grant program by CHP developers and supporters was the funds distributed by the DOE under the *American Recovery and Reinvestment Act of 2009* (ARRA). Under this program, approximately $100 million was awarded to CHP and waste heat recovery projects, and a small number of CHP projects was able to move forward that would likely have not otherwise been implemented, according to developers familiar with some of the awardees. Interestingly, some developers noted that the short-term ARRA grant program actually temporarily stalled the deployment of CHP systems around the country, as applicants awaited notification of their selections. But applicants did note that they generally received news about whether or not they were selected for the grant in a timely manner.

The ARRA money has been entering the CHP marketplace slowly. Projects that were awarded funds are now just beginning to break ground, or are still in the preliminary planning stages. It remains to be seen what the impact of the ARRA funds will be on the CHP market, but it is clear that interest in the program was widespread among CHP developers. According to those familiar with the program, the program was substantially oversubscribed, and the vast majority of applicants were thus denied funding due to a finite amount of resources. However, the interest and enthusiasm for government support of CHP projects was notable among the developers and supporters. “Anytime the federal government throws money at CHP projects, it’s a big deal,” said one developer.

Developers also expressed substantial support for the Section 1603 payments for energy property in lieu of tax credits (United States Treasury 2010), which is another special short-term program authorized under the ARRA. The fact that payments under this plan are made up front, instead of as tax credits to be enjoyed after the capital costs have already been incurred, significantly reduces the challenge of securing financing, as any amount to be financed is reduced by the amount of the Section 1603 payment. It therefore also reduces the overall cost of a project, because the developer or owner does not have to incur the cost of capital when securing the upfront financing covered by the payments.

According to one developer, these payments, and the presence of grants for CHP in general, has “been huge” for the continued development of new projects. Other CHP stakeholders agree. Section 1603 payments will revert back to the standard 10% federal investment tax credit once the ARRA payment program ends at the end of 2010.[3] According to CHP developers, the termination of the special program will impact the CHP market. According to one developer, the standard tax credit amounts to “the same amount of money [as the ARRA payments] with half the impact.”

Portfolio Standards

The inclusion of CHP and waste heat in an energy portfolio standard has traditionally been viewed by CHP supporters as important in strengthening the CHP market. This inclusion usually comes in the form of an energy efficiency resource standard (EERS) or an alternative energy portfolio standard that includes CHP or waste heat recovery as qualifying resources. When CHP or waste heat is included in an EERS, it means the state requires regulated utilities to meet some percentage of future energy use with CHP or waste heat. Sometimes CHP is specifically called out and assigned a percentage of future use, and other times it is part of a large group of technologies that may all count towards a certain required percentage. To date, 18 states allow some sort of CHP or waste heat to qualify as a resource for a state energy efficiency or alternative energy standard (Molina et al. 2010).

According to developers, CHP’s inclusion in a state’s EERS or other portfolio standard does not yet have a substantial market effect. “We haven’t seen this make a very big impact,” said one advocate in the South. The policy is generally viewed as having no teeth, in part because so many portfolio standards have only been in place a few years. Most of these policies have set goals 5, 10, or even 20 years into the future, so the impact on the current CHP market has been minimal. All CHP developers agreed that such policies could make bigger impacts years from now, when resources prioritized in EERS policies become worth more to utilities wishing to meet their goals.

Some developers said that state portfolio standards could be altered to better encourage CHP. They noted that because CHP is typically bundled into the same resource category as other energy efficiency investments, it does not benefit very much from inclusion in an EERS. Energy efficiency investments are generally cheaper than CHP from a first-cost perspective, so utilities prioritize them. Developers said that

[3] The Section 1603 payments in lieu of tax credits can be taken for energy property placed in service in 2009 and 2010. The payments may be taken through 2017, depending on the type of energy property placed in service. More information about this program can be found at http://www.treas.gov/recovery/1603.shtml.

a separate tier specifically dedicated to CHP and waste heat resources would be one way to ensure that CHP represented a specific percentage of future energy use.

CHP is sometimes included as an eligible resource in Renewable Portfolio Standards (RPS), but often only renewable-powered CHP or strict "waste heat" is allowed as an eligible resource. Developers said that an ideal method to encourage all forms of CHP would be to include renewable-powered CHP and waste heat in an RPS and include new fossil fuel-fired CHP in an EERS.

What Role Should Incentives Play?

While incentives clearly appear to play an important role in encouraging CHP development, it appears they are most effective as a complement to other efforts to remove market barriers. Tax incentives and production credits, as well as feed-in-tariffs, have the ability to move markets locally. However, "Incentives don't necessarily translate into a market for your power," noted one developer, so there is a limit to what incentives can do for a project's bottom line. While incentives can make a state more attractive for CHP projects, they will not by themselves greatly enhance the economics of a project. Few projects appear to have advanced solely due to the presence of incentives. Incentives do not directly remove regulatory barriers, but they can help mitigate the increased costs presented by those barriers. The incentives that were viewed as "substantial" by developers and supporters have clearly impacted the CHP markets they serve, according to the developers who work in those markets.

Among the incentives currently in place, some developers found flaws in the way they are administered and how they impact projects. "Competitive grants do us no good," said one developer, referencing the seemingly endless paperwork required for application. Like others discussing the impact of the ARRA grants, this developer noted that once a grant has been solicited, the CHP project is effectively stalled, awaiting notification from the grant-awarding party. "It stalls the project, sometimes for years," especially if the project ends up not receiving the grant in question. Developers find themselves back at "square one," seeking the funding or financing that they had anticipated the grant to cover.

In addition, incentives appear to be rarely directed at the very early stages of project development. Multiple CHP developers noted that grants to help fund project feasibility studies are in short supply. "Nobody wants to finance that," said one developer, despite the fact that economic modeling and financial analysis help improve projects and maximize their economic return before any ground is broken. According to these developers, grants or funds that would help pay for feasibility assessments are too risky for most traditional financing sources, because many projects are ultimately deemed uneconomic at the end of a feasibility assessment.

CHP developers also noted that many incentives are "here one year, gone the next." This lack of persistence makes developers leery of planning CHP projects around incentives. In particular, developers cited incentives in Connecticut and California as ones that had been in place during project conception but were not renewed by the time the project was ready to break ground. "That really threw things off in the market," said one developer, of the cancelled 450 per kW grant for base load distributed generators in Connecticut.

Some CHP supporters have expressed concerns that the presence of incentives can distort the market. CHP supporters noted that they were aware of many uneconomic projects that sought ARRA funding. These projects were generally not awarded funds, suggesting that the ARRA grant program rightly declined to fund projects that did not make long-term economic sense. When sized correctly and matched with an appropriate thermal load, a CHP system can make good economic sense, even in areas with cheaper power or more expensive fuel. But a CHP project that is poorly sized or a poor fit for a given facility will have a difficult time appearing to make economic sense, even with incentives.

Financial incentives can help overcome borderline economics, but they cannot overcome very bad economics. And while financial incentives for CHP may indeed encourage development, they are not sufficient alone to create a favorable market for CHP.

Other Barriers

The economic and financial realities of CHP projects play a key role in whether CHP projects are developed. Rather, the removal of regulatory and market barriers is often fundamental to the successful implementation of CHP systems. As noted in the Economics sections, giving CHP projects greater access to a market for their excess power is one way to make more CHP projects economically sound in the long run. Removing in-place barriers is another way to reduce overall project costs and increase the long-term return on investment. This section discusses the barriers most discussed by CHP developers and supporters as impacting the current CHP market.

Carbon Regulation Unknowns

The specter of future carbon dioxide regulations or a cap-and-trade system is one of the main reasons developers cite for an increased interest in CHP over the past few years. Many companies have begun to consider investing in CHP for the first time in order to satisfy corporate mandates for energy efficiency and/or greenhouse gas reductions. However, now that a federal cap-and-trade scheme appears very unlikely, facilities are simply waiting to determine what impact other potential regulations on carbon dioxide and criteria pollutants will have on their business operations. Some CHP developers said that their standard practice is to integrate a theoretical price of carbon into project proposals, even though such hypotheticals cannot be integrated into a project's financial forecasts. One developer said that he encourages clients to take a long-term approach to investing in CHP. "Carbon will eventually be the biggest [economic] impact on these systems, second only to the cost of money," he said.

For now, though, developers report that many facility owners are sitting back and waiting to see what transpires over the next few years in pollution regulation. They are unsure how efforts like the Western Climate Initiative and the Regional Greenhouse Gas Initiative will ever truly impact their facilities, given the lack of clarity of how the U.S. Environmental Protection Agency (EPA) will decide to regulate greenhouse gases under the Clean Air Act. Developers and supporters alike are awaiting a clearly delineated outline of how policies encouraging carbon dioxide reductions and other environmental benefits of increased energy efficiency will impact CHP projects' bottom lines.

Regulatory Bodies

Utility regulatory commissions are frequently responsible for determining how regulated utilities can spend public funds on energy efficiency and renewable energy programs. Typically, these commissions require that energy efficiency programs, which usually house any CHP programs or incentives, must satisfy some type of cost-benefit test. Total resource cost (TRC) is a common test, executed to ensure that the present value of an energy efficiency investment is greater than the present value of the cost of implementing the investment. The TRC test is actually quite complex, but suffice it to say that CHP projects and programs regularly fail TRC tests. This is due largely to the long time period over which CHP projects recoup their costs. Generally, there are smaller energy efficiency projects that are easier to execute and cost less per kWh saved than CHP.

CHP supporters argue that the full benefits of CHP—including benefits that are realized years down the road—are not incorporated into a TRC test. Long-term benefits to system reliability as well as a decreased need for new large-scale generating plants in the future are two of the long-term benefits not often factored into a TRC test. Supporters thus argue that CHP is far more beneficial than a TRC test would indicate. They further argue that CHP should not have to satisfy a TRC test (comparing it to much cheaper and smaller energy efficiency projects) and should instead be prioritized in and of itself.

These arguments represent one of the biggest barriers to CHP: CHP, as far as policies are concerned, is often effectively "homeless." Because it is often powered by fossil fuels, CHP rarely fits into renewable energy programs. Because it supplies electricity and is larger and more complex than simple energy efficiency measures, it rarely fits into standard utility or local energy efficiency programs. Sometimes it is treated simply as a "fuel switching" measure and not as an improvement of any sort. There are only a handful of true "CHP programs" among utilities and state energy efficiency programs. These programs, such as those administered by the New York State Energy Research and Development Authority, help bolster local CHP markets significantly. But these dedicated CHP programs are rare, and CHP supporters believe state regulatory commissions could do more to prioritize and foster such programs.

Interconnection

Interconnection, which is the process of connecting a CHP system to the local distribution or transmission grid, can be a substantial barrier to CHP deployment, especially for smaller (under 5 MW) CHP projects in areas without an interconnection standard. Though widely accepted engineering standards for interconnection exist, CHP developers still find that many utilities can make the interconnection process very cumbersome and expensive. States that are interested in encouraging CHP and other types of distributed generation have developed their own interconnection standards to which the state's regulated utilities must adhere. To date, 31 states and the District of Columbia have developed interconnection standards that delineate how to interconnect at least some CHP systems of varying sizes (Molina et al. 2010).

When an interconnection standard is in place, it gives a CHP developer an official avenue to apply for interconnection with the local utility. It also provides an official platform on which to bring grievances against a utility to the state's regulatory commission, should the utility fail to adhere to the state's regulations. Some states offer special expedited interconnection processes for the smallest CHP projects, which, according to one developer, "confers the full benefits of the idea behind an interconnection standard." Interconnection standards give developers some level of assurance that a utility will not act capriciously in considering an interconnection request.

CHP developers and supporters indicate that interconnection can still be a "big pain" for numerous CHP projects, even in states with standards in place. This appears to be a result of the additional equipment or engineering studies a utility may require before it approves interconnection. These kinds of additional requests often fall well within the existing standard, so CHP developers do not have much recourse to challenge such additional requirements. Though utilities may be technically adhering to the "letter of the law" on interconnection, they may not be adhering to the spirit.

"If the utility wants to make interconnection a pain, they will do everything they can to make it a pain," said one developer. "But they'll also make it easy if the CHP system is somehow beneficial to them." The interconnection process can deeply color the experience of installing a CHP system. One Midwest developer said that after successfully interconnecting a CHP system after years of back-and-forth with a very uncooperative utility, his customer told him, "I love this CHP system. It's doing exactly what I thought it would do. But I would never do this again."

Interconnection does not appear to be as much of a barrier to large projects as it is to small ones. Large projects, by the time they apply for interconnection, have generally already discussed interconnection with the utility and can anticipate the additional studies or equipment the utility may require. The additional requirements made by the utility account for a much smaller percentage of the total cost of a larger project, and are easier for the developer to incur. Additionally, some of the largest projects, such as those over 20 MW, are often subject only to the interconnection standards promulgated by the Federal Energy Regulatory Commission, as they so often interconnect directly to transmission lines instead of distribution lines. The FERC standards are the same across the country and relieve developers from dealing with the vagaries of interconnection with the local utility.

In contrast, complying with interconnection standards and meeting additional equipment or study requirements can be a financial burden for smaller CHP projects. "A $50,000 interconnection study may not be a big deal for the big guys, but that'll kill a small project," said one developer. Generally, interconnection for a smaller system can succeed if a developer puts enough time into the process. However, the path to success is often expensive and time-consuming. Many developers say that at some point they will just decide "it's not worth it" to continue to pursue interconnection.

However, there is good news to report. In general, CHP developers and supporters said that interconnection procedures seem to be easing across the country. Utilities that were viewed as "bad" interconnection partners have, to some degree, improved their interconnection processes and business practices. In part, these changes are due to Section 1254 of the *Energy Policy Act of 2005*, which required states to consider interconnection standards for small generators. The outcome of this requirement was that state regulatory bodies across the country opened dockets to consider interconnection, which gave CHP supporters and developers an opportunity to espouse the benefits of CHP. While interconnection remains a barrier for certain projects, it appears that slow and steady progress is being made.

Utilities

Throughout this research, CHP developers and supporters indicated that one of the biggest hurdles facing new CHP projects today is uncooperative electric utilities. These companies and utility districts are especially concerned with protecting their business interests and are understandably hesitant to support projects that will reduce their revenues or otherwise threaten their business models. However, some utilities are more amenable than others, and utilities that have some external incentive to support CHP—efficiency requirements from regulators, grid constraints that could be eased by CHP, etc.—tend to be better partners for CHP projects.

"Personally, I think utilities are the problem," said one developer in the Southwest. "Utilities worry about losing load to CHP, but with a new building development, they're not losing the load—they don't have it yet." This opinion was echoed by many other developers and supporters, who argue that in new building developments, utilities should have to compete with CHP on efficiency. "They can't beat my heat rate," said one developer. "The only way they'll let me play in the market is if they're desperate for power themselves."

There are several ways utilities can work to frustrate, stall, or even kill CHP projects. These include:

- Creating onerous and opaque interconnection requirements, and failing to adhere the spirit of laws governing utility behaviors by causing unnecessary project delays or roadblocks
- Offering special discounted electric rates to facilities considering CHP and thus harming the project's payback period and value to the facility
- Requiring that any CHP projects be owned by the utility and thus reducing the economic benefit to the project-owning facility

Developers working in each state note that they are aware of which utilities are easier to work with than others. In some states, certain utilities are known to be "non-starters" and few, if any, CHP projects are proposed for their service areas. "Why waste my time with them?" asked one developer. "They're too difficult to work with, so I take my business elsewhere." Developers know that it is fruitless to work to expand their business into areas served by these difficult utilities.

In part, the regulatory commissions in each state have the authority to develop incentives for utilities to be more open to CHP. These incentives can include alternative utility structures in which utility revenue is not directly linked to the amount of electricity sold. It can also include directing public funds specifically toward CHP projects and programs, and requiring that CHP incentives and technical support be offered in conjunction with other energy efficiency or renewable energy programs.

Because regulatory commissions have little to no control in the operations of municipal utilities or cooperatives, developers said that working with municipal utilities or cooperatives can sometimes be a "crapshoot." Generally, developers find municipal utilities to be fairly progressive in their environmental goals and most concerned with which energy resources are truly best for the community they serve. They also find that municipal utilities tend to follow the lead of IOUs in the area.

Permitting

In addition to dealing with interconnection standard requirements, there are other permits and regulations that CHP systems are subject to. These can include:

- Air emissions regulations
- Fire department permits (for natural gas lines)
- Buildings permits (for construction)
- Noise regulations

In general, satisfying these various permitting processes—including the requisite legal fees—can amount to 2 to 3% of project cost for medium-to-large projects. However, for very small systems, these costs can sometimes represent 10 to 15% of the cost, effectively killing a project if one particular permitting process becomes too expensive or too daunting. Developers indicated that these challenges become much bigger portions of total projects costs for projects under about 3 MW.

These costs are upfront project costs, “so someone has to pony up the money before anything can actually be built,” said a developer. There is some risk involved in paying for permitting processes, because a project could be halted indefinitely at any time. “The fees themselves aren’t that bad,” explained one developer. “But the time and effort you spend modeling your system’s emissions can be expensive.” Certain regulations, like building codes, do not explicitly outline how to work with CHP systems, so a developer working for the first time in a certain municipality or state may not know what to expect.

One developer suggested that permits, especially those for air emissions, be developed like interconnection standards, with clear paths and time lines and fees explained outright. Developers said that these permitting processes can often take up to two years to complete before any construction can begin.

Interestingly, satisfying air emissions regulations did not appear to be a significant barrier, according to CHP developers. “Permitting may not seem like a big issue,” said one advocate, “because so few projects actually get to that point.” Most CHP developers indicated that they have a working knowledge of all applicable air emissions regulations for each region in which they work, and so will steer clear of particular technologies or project designs that they know will not satisfy local air regulations.

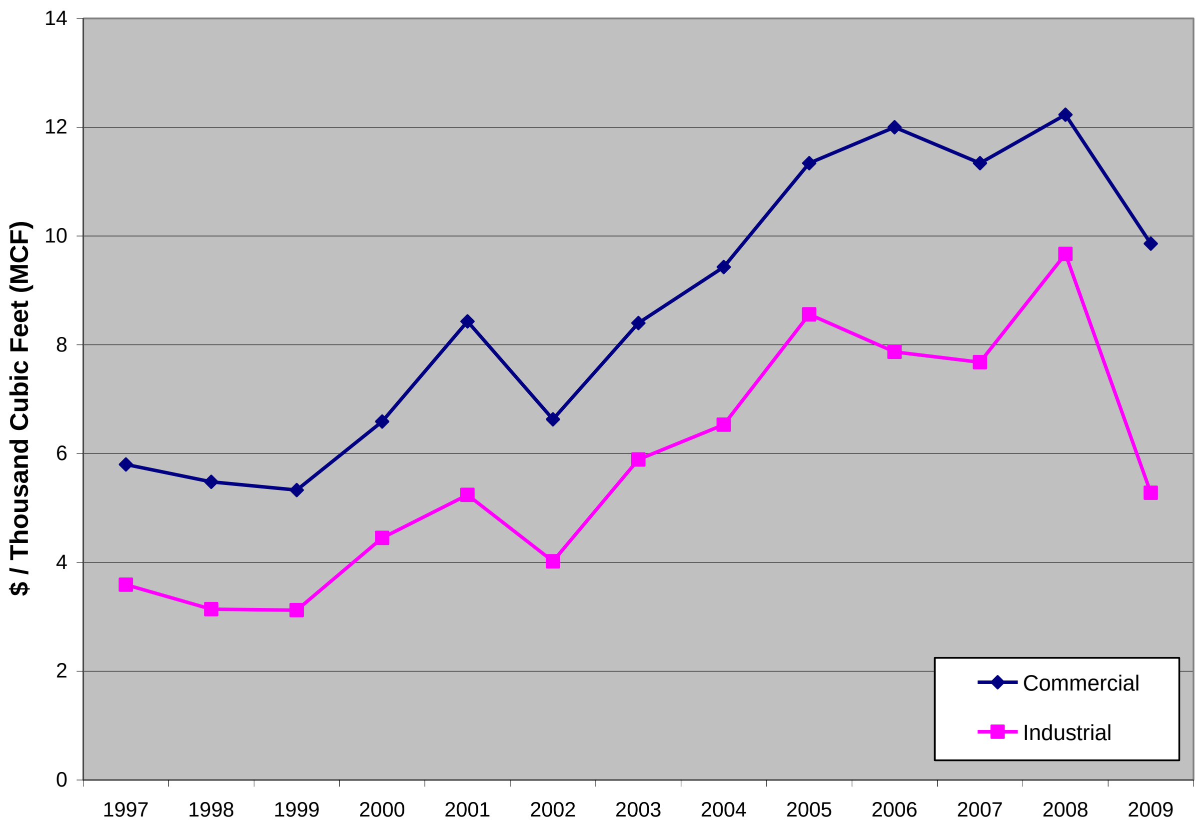
It may be that certain air regulations influence which kinds of CHP projects are even considered at the beginning of a project’s lifespan. “Permits basically set the fuel mix” of an area, said one developer. No project will be developed that exceeds permit levels, so in-place emissions regulations greatly color which kinds of CHP technologies are considered in any given location. Existing industrial facilities are keenly aware of what kinds of activities may trigger a review under the Clean Air Act, and prefer to avoid those activities if possible. Installing a new CHP system can trigger such a review, but many industrial companies calculate that the costs are worth it in the long run. Since larger CHP projects generally emit greater amounts of emissions, larger projects are often more burdened by emissions regulations. An advocate in California, which has some of the strictest emissions regulations in the country, noted that there has been a slowdown in large projects—greater than 20 MW—since the emissions rules came into effect in 2007.

As possible greenhouse gas regulations are considered at the local, state, and federal levels, developers are particularly concerned that CHP will be unfairly treated in new regulations. CHP sometimes increases the emissions onsite, but due to its high efficiency, reduces the overall emissions in a given region. Output-based emission standards recognize this reality and give CHP systems credit for the higher efficiency of their power output. Some states have output-based emissions in place for certain pollutants, and CHP developers and supporters are working to ensure that future air emissions regulations will be output-based.[4]

Natural Gas

Natural gas, which fuels over half of all recently installed CHP systems in the U.S., is a largely unregulated commodity whose price is set on the open market (ORNL 2008). Because CHP payback and general economic attractiveness are based largely on how much the fuel to run the system will cost, fluctuations in the natural gas market have historically impacted CHP project deployment (ORNL 2008), especially in areas where centralized generation assets are largely fueled by resources other than natural gas. The past ten years have seen large fluctuations in the price of natural gas (see Figure 1) and, despite the fact that natural gas prices have been relatively stable for the past 20 months (EIA 2010a), CHP developers note that potential CHP investors and host facilities still cite gas price volatility as a major reason not to invest in CHP.

Figure 1. Historical U.S. Natural Gas Prices



Source: EIA (2010a)

CHP developers note that it may take a while for would-be project owners to feel comfortable investing in something so dependent on a previously volatile commodity. In some states and localities, discounts on natural gas sales for CHP systems have served to reduce the impact of market volatility. Recently, new shale fields have been identified across the U.S., lowering natural gas prices substantially and causing investors across the utility industry to look to natural gas as a primary fuel for future growth (Casselman 2009). Until potential CHP owners also begin to view natural gas as a smart long-term fuel choice, CHP projects will continue to suffer from concerns about the risks of natural gas.

[4] For more information about output-based emissions, visit the U.S. EPA's Combined Heat and Power Partnership page on the topic: http://www.epa.gov/chp/state-policy/output.html.

Standby Rates

Standby rates, which are the rates an electric utility charges a CHP system's host firm for additional or backup power and backup system capacity, have the potential to ruin a project's economics. These rates are used to charge a facility for the power it buys for the following purposes: to supplement a CHP system, when a CHP system unexpectedly goes down, and when a CHP system is taken offline for scheduled maintenance.

Standby rates are often calculated on the assumption that a utility must brace itself in case every CHP system in its service territory breaks down at the exact same time, which is not a realistic concern. Standby rates are typically developed in close cooperation with regulatory commissions, and regulators tend to require utilities to plan for worst-case scenarios in order to ensure that all customers can have power if such a scenario does occur. In order to ensure that all necessary backup power can be provided simultaneously, utilities contend that they need to build the infrastructure for it—that is, the transmission and distribution wires to deliver the electricity. It is these kinds of additional investments in infrastructure that are incorporated into calculations for standby power.

In many states, standby power charges can be exorbitant for CHP systems that have only needed utility power once, for a few minutes, during the whole year. Utilities employ "demand ratchets," which penalize a company for one moment of high demand by ratcheting up the rate at which all subsequent standby power is purchased. These kinds of practices are highly detrimental to the economics of some projects, and frustrate developers and supporters across the country.

There appears to be substantial room for improvement. "Standby rates generally don't take into account the benefits a CHP system has on the whole grid," explained an advocate. He added that it is ludicrous to assume all the CHP systems could go down simultaneously. In many cases, he noted, CHP systems have helped to stabilize grids during times of high electric demand and to reduce transmission losses at all times. At present, CHP systems are generally not rewarded for providing those kinds of benefits, and such benefits are certainly not recognized in the design of current standby rates.

According to one developer, the best standby rates are those that "don't use hatchets—they use scalpels" to design fair rate structures that encourage CHP systems in areas that could benefit from them. But such standby rates are rare. In several states, developers noted standby rates to be one of the greatest barriers, able to kill projects entirely by skewing their economics.

General Findings, Thoughts and Conclusions

Though the focus of this research was primarily on the differences in CHP markets among states, a great number of common themes emerged. The economics for many CHP projects are currently bad, due in large part to the economic recession and the aversion to risk exhibited by business owners and financial firms. There is an argument to be made that the payback period and other measures of a project's economic viability do not sufficiently take into account the long-term benefits that CHP projects may provide. These arguments are made by CHP developers every day, but are not always effective at convincing a business or facility owner to take a longer-term view. Though there are some active financial incentive programs that address CHP markets and help move forward projects that may not otherwise be developed, incentives themselves cannot make uneconomic CHP projects viable.

A variety of regulatory and policy barriers continue to plague CHP projects. The good news is that some of these barriers appear to be lessening each year. Along with leadership by the DOE and EPA, states have been working to remove some of these barriers. The success of their efforts varies widely, as is illustrated in the next section of this report.

The following section will highlight barriers and opportunities unique to each state, as viewed through the eyes of individuals intimately familiar with the challenges of deploying CHP projects in each state. Though some general themes prevail, it is evident that certain states offer CHP developers a healthy and robust environment for CHP, while other states remain completely unattractive to developers. Though it remains a challenge to develop CHP projects in all areas of the U.S., CHP is making inroads and continuing to prove itself to be a reliable, cost-effective, and environmentally sound energy resource.

PART II: STATE PROFILES

In this section, direct feedback from CHP developers and supporters is presented in the aggregate to help describe the current CHP market in each state. Pertinent facts and figures about each state are summarized, and highlights from conversations with area CHP developers and supporters are shared. Illustrative examples of recent or current projects are discussed as evidence of particular issues mentioned by developers and supporters. Specific policy recommendations suggested by developers and supporters are also shared.

Statements in each profiles are not necessarily the opinions of the authors, but instead a reflection of the general opinion of those working in each state. Sentences or phrases within quotation marks are direct quotations from particular developers or supporters, and every attempt to convey the original context of the quotation has been made. Readers may note that some profiles are much longer than others; some states were popular topics of discussion for many developers and supporters, while others did not engendered much discussion or excitement about current CHP activity.

These profiles in no way attempt to describe a state's current CHP environmental in full. Rather, these profiles represent some of the most common and representative comments made by the individuals uniquely familiar with the realities of developing CHP projects in each state. Their main purpose is to characterize each state's CHP environment, as viewed by the individuals most familiar with it. These profiles are not to be viewed as an exhaustive account of all relevant policies in each state.

In instances where particular policies were discussed as important by developers and supporters, they are noted in the State Profile. For additional information about existing policies in each state, refer to ACEEE's *State Policy Database*, an online resource with current information about the CHP-related policies each state has implemented.[5]

An Explanatory Note about Terms Used in this Section

Each State Profile features a Quick Facts box on the right hand side of the page. These boxes offer some useful and relevant facts about the state and its energy markets. Much of the data used to populate the below categories can be found in detail in the Appendix.

New CHP Sites (2005–2010)

This value is the number of new CHP projects built in the state between 2005 and 2010. The parenthetical number is the state's rank among all U.S. states in this category, with #1 being the state with the highest number of new CHP sites. This data is publicly available from ICF International, which maintains a database of installed CHP systems in each U.S. state. The data collection is supported by the U.S. Department of Energy and Oak Ridge National Laboratory. The data can be found online at: http://www.eea-inc.com/chpdata/index.html.

New CHP Capacity (2005–2010)

This value is the total installed capacity of all CHP systems installed between 2005 and 2010, per the ICF International database referenced above. The parenthetical number is the state's rank among all U.S. states in this category, with #1 being the state with the highest amount of new CHP capacity

Average Capacity per Site (2005–2010)

This value is the total installed capacity of CHP systems installed between 2005 and 2010, divided by the number of new CHP sites installed between 2005 and 2010. This data is also from the above referenced ICF International database.

[5] The *State Policy Database* is available online at: http://aceee.org/sector/state-policy.

Total Primary Energy Consumption (2009)

This value is the total energy consumption of all sectors of the states economy in 2009, in BTUs. The parenthetical number is the state's rank among all U.S. states in this category, with #1 being the state with the most primary energy consumption. This information is from the U.S. Energy Information Administration.

Average Gas Price (2009)

This price is the average retail price, in 2009, per 1,000 cubic feet (MCF) of natural gas purchased in the state. This average is taken across the residential, commercial, and industrial sectors. This information is from the U.S. Energy Information Administration. Price information for all three sectors was not available for several states. In such cases, the following symbols, used after "MCF" in the Quick Facts box, denote the sectors used to calculate the average price:

- * Commercial and Residential only
- ** Industrial and Residential only
- † Industrial and Commercial only
- ‡ Residential only
- ℓ Commercial only

The parenthetical number is the state's rank among all U.S. states in this category, with #1 being the state with the highest average gas prices.

Electricity Price (2010)

This value is the average retail price, in 2010, of one kWh of electricity purchased in the state. The average is taken across all sectors, and is the average taken January through September of 2010. The parenthetical number is the state's rank among all U.S. states in this category, with #1 being the state with the highest average electricity prices. This information is from the U.S. Energy Information Administration.

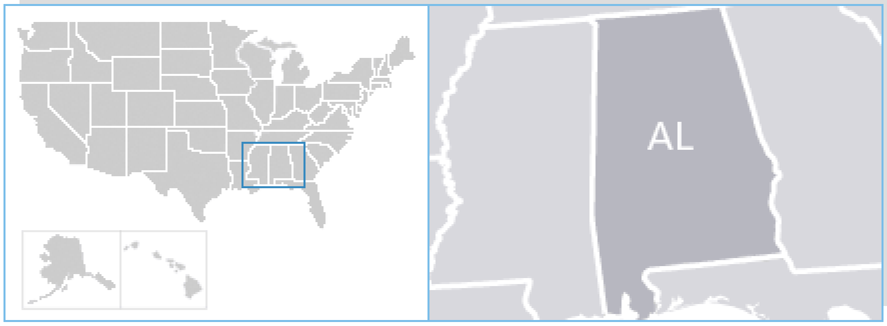
Energy Consumption by Sector

These pie charts represent the percentage of overall energy consumption of each major sector of the state's economy in 2008, according to the U.S. Energy Information Administration. Much of the relevant background data for the EIA's findings can be found here:
http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.

Pie chart key:

R = Residential
C = Commercial
I = Industrial
T = Transportation

ALABAMA



New CHP Sites (2005-2010):
3 sites (#26)

New CHP Capacity (2005-2010):
47.0 MW (#11)

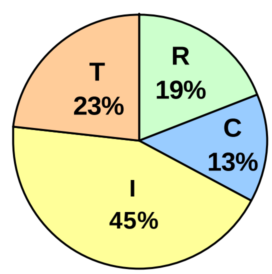
Average Capacity per Site (2005-2010):
15.7 MW

Total Primary Energy Consumption (2008):
2,065 trillion Btu (#16)

Average Gas Price (2009):
$13.41 per MCF (#7)

Average Electricity Price (2010):
8.97¢ per kWh (#26)

Energy Consumption by Sector



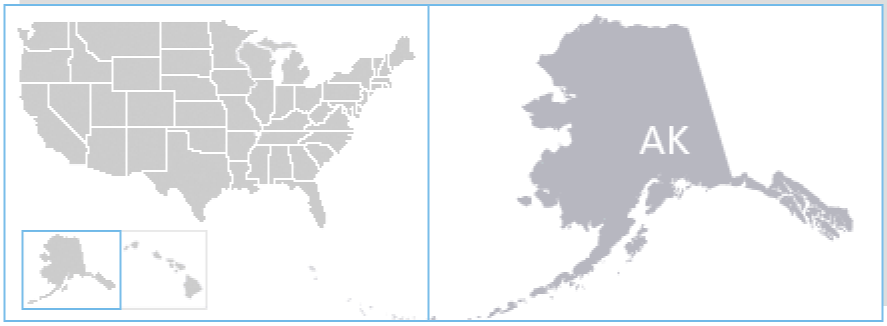
The CHP market in Alabama is not a favorable one. The state scored only one point out of a possible five in ACEEE's *Scorecard*, and has seen the installation of three new CHP projects between 2005 and 2010. The total new installed capacity between those years was about 47 MW, including a 30 MW biomass-fueled project at a mill producing sustainable forest products.

The biggest barrier to new project deployment in Alabama is economics. Even large projects (and in-place CHP projects in Alabama are disproportionately large) do not always make sense to build due to the state's cheap electric rates. Alabama offers several incentives that are not directly designed to encourage CHP, but could be used for some CHP projects, particularly in the public sector.

Utilities have not made the CHP market any more favorable. Alabama Power (Southern Company) has very unfavorable standby rates, and supporters note that Alabama Power has been "not at all helpful" in discussing possible CHP projects with industrial customers. The state has no interconnection standards, so project developers do not face a clear timeline or list of necessary studies to be completed before interconnection can occur. Utilities have taken advantage of this and have stymied many projects along the way.

The only active energy efficiency programs in the state are those administered by the Alabama Department of Economic and Community Affairs (ADECA). It administers a grant and loan program to help fund energy efficiency and renewable energy investments at local government facilities and in the agricultural industry. In late 2010, ADECA launched a brand new program called Alabama Saves. Developed with ARRA funds, the loan program offers loans at an annual interest rate of 2%, up to $4 million in size. The $60 million revolving loan fund specifically targets Alabama's commercial and industrial sector businesses. ADECA has partnered with several engineering firms and an energy financing firm to help would-be applicants conduct an initial energy audit and identify possible projects that could take advantage of the loan program. This is the first time such a program has been offered in Alabama, and it remains to be seen what kind of an impact, if any, it might have on CHP deployment in the state.

ALASKA



New CHP Sites (2005-2010):
1 site (#43)

New CHP Capacity (2005-2010):
0.4 MW (#42)

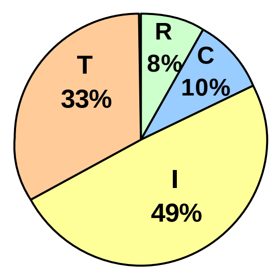
Average Capacity per Site (2005-2010):
0.4 MW

Total Primary Energy Consumption (2008):
651 trillion Btu (#39)

Average Gas Price (2009):
$7.76 per MCF (#42)

Average Electricity Price (2010):
14.84¢ per kWh (#5)

Energy Consumption by Sector



The CHP market in Alaska is very unique. A major portion of the state is located off the state road system and off the electric and natural gas transmission lines. "The bush," as this area is called, contains nearly 200 individual villages that can only be reached by plane or boat. 95% of power generation in bush Alaska comes from diesel. Despite Alaska's wealth of petroleum resources, it has little refining capability, and must import most of its diesel from refineries in Washington State. Thus, diesel is very expensive in Alaska—sometimes over $9/gallon—and is three to five times more expensive in the rural areas than the urban ones (AEA 2010).

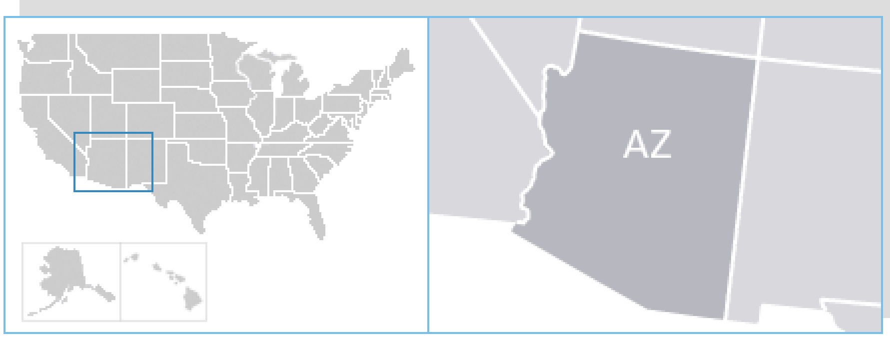
Few CHP projects use natural gas due to its price and scarcity. Heating systems are gaining momentum in the bush, however, powered by the recovered excess heat from diesel generators. These systems have largely been funded with loans and grants from the state and the Denali Commission, a state-federal partnership targeting the state's rural areas. About 90 of these systems are in place, though some are not operational.

In addition to waste heat recovery, biomass-powered CHP represents the next biggest opportunity in the state. If planned wildfire mitigation efforts take place, abundant biomass resources will be available in certain areas. The state currently administers a $250 million grant program to support renewable energy projects, including biomass-fueled CHP. This program has been a successful incentive for biomass projects and continues to be tapped by communities all over the state.

Alaska's rural communities are largely served by electric cooperatives, while the few urban areas are served by a combination of investor-owned utilities and municipal cooperatives. Issues such as interconnection and net metering are generally managed on a hyper-local scale. A CHP system will often be the main electricity source for a whole community. With all fuel prices so high, all utilities appear to be on board with CHP, though barriers remain. These include high fossil fuel prices, a lack of technical skills among residents who might help shepherd CHP projects in their communities, and the difficulty of moving biomass from its source to the point of incineration.

In Alaska, "if the economics are there, [CHP projects] get developed." Regulatory hurdles appear to be fairly nonexistent, and the state government itself appears to be quite supportive of CHP that is fueled by in-state resources.

ARIZONA



New CHP Sites (2005-2010):
2 sites (#34)

New CHP Capacity (2005-2010):
16.3 MW (#20)

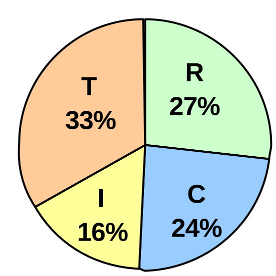
Average Capacity per Site (2005-2010):
8.1 MW

Total Primary Energy Consumption (2008):
1,553 trillion Btu (#24)

Average Gas Price (2009):
$12.67 per MCF (#10)

Average Electricity Price (2010):
9.86¢ per kWh (#19)

Energy Consumption by Sector



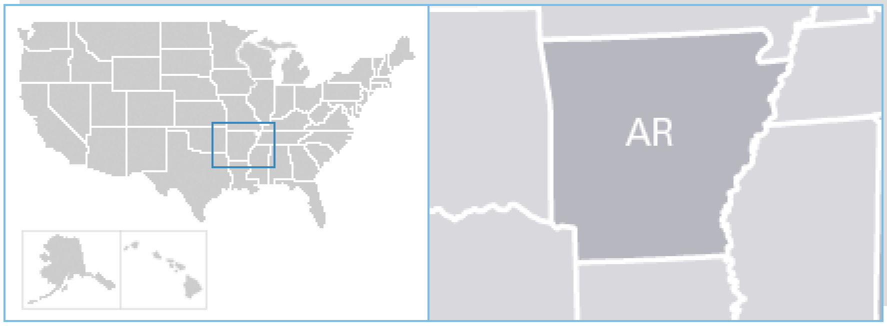
Arizona's CHP market is better than the rest of the Southwestern U.S., but is only average among all U.S. states. Arizona scored 3 out of 5 on ACEEE's 2010 *Scorecard*, reflecting good portfolio standards and net metering policies. Between 2005 and 2010, the state installed two new CHP systems with a combined capacity of 16.3 MW.

The main barrier to new CHP in Arizona is economics. Electricity is cheap, and despite gas utility incentives of $400–500/kW across much of Arizona, few projects have been moving forward lately. Bad standby rates make the economics of projects even worse, and rates from Arizona Public Service Company are viewed as "the worst." However, additional financial incentives from ARRA programs have jump-started interest in CHP in the state, causing a handful of new projects to be considered. Several of the projects going forward have payback rates of less than three years, which appears to have satisfied decision-makers at facilities such as hospitals and hotels.

The practice of offering facilities considering CHP cheaper electricity rates to discourage CHP projects appears to be used in Arizona. This has been a bigger problem among the state's investor-owned utilities. Interconnection is also a barrier in the state, as Arizona chose not to adopt statewide interconnection standards in response to the federal Energy Policy Act of 2005, which required that states consider adopting updated interconnection standards. Instead, each major utility has developed its own interconnection processes, which are regarded as hard to work through but not project-killers: "When you get to the point of interconnection, you can probably plow through it, but you won't be very happy."

Air emissions regulations do not appear to have stalled CHP projects in the state, while several regulations designed to encourage CHP do not appear to have yet made much impact on the market. The state's RPS counts renewable-fueled CHP as an eligible resource, and has been used to move a handful of biomass and biogas-fueled CHP projects forward. In addition, the state's 2009 EERS, which counts all CHP as an eligible resource, will begin to go into effect in 2011. The new standard could present new opportunities for CHP and could help remove some utility resistance.

Arkansas



New CHP Sites (2005-2010):
2 sites (#34)

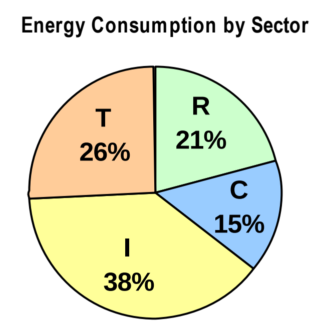
New CHP Capacity (2005-2010):
5.3 MW (#30)

Average Capacity per Site (2005-2010):
2.7 MW

Total Primary Energy Consumption (2008):
1,125 trillion Btu (#31)

Average Gas Price (2009):
$10.87 per MCF (#25)

Average Electricity Price (2010):
7.30¢ per kWh (#45)



The CHP market in Arkansas is not favorable. The state received a one out of five in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Arkansas installed two new CHP systems with a combined capacity of 5.3 MW.

Arkansas's interconnection standard applies only to certain renewable energy systems, so it only applies to CHP fueled by renewable resources. The standard also applies only to non-residential systems under 300 kW in capacity. Because most CHP systems are far larger, this interconnection standard—even if it explicitly included CHP—would fail to provide a clear path for interconnecting to the grid for most, if not all, viable systems.

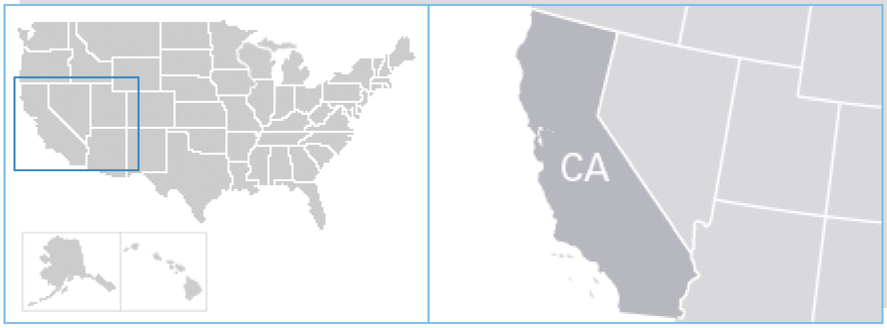
The Arkansas Energy Office has identified financial constraints as one of the largest barriers to CHP. The state of Arkansas does not currently offer any financial incentives for CHP, and because CHP installations tend to be capital intensive and require large upfront costs, financial hurdles often preclude development. With very low electricity prices in the state, it is difficult to justify investing upfront capital in CHP projects with such extensive payback periods projected. In the current economic environment, many facilities the Arkansas Energy Office has contacted have said that they simply do not have the capital at this time for major projects, regardless of energy savings projections.

In many cases, facilities have considered biomass CHP systems using wood chips or shavings but have been unable to secure a steady fuel supply. If alternative fuel sources, such as dedicated energy crops, were to become readily available, the market for CHP in Arkansas would be significantly improved.

Stakeholders in Arkansas have pointed to other implementation challenges stemming from utility contracts that are made with potential CHP hosts. Through these contracts, utilities have established special, discounted rates for customers considering a large CHP project in order to prevent the project's development and maintain the sale of the electricity being consumed at that facility.

Many facilities and developers are not aware of where they can obtain support for CHP project research and implementation, such as the Department of Energy's Southeast Clean Energy Application Center, whose express mission is to facilitate the development of CHP in the Southeast.

CALIFORNIA



New CHP Sites (2005-2010):
140 sites (#1)

New CHP Capacity (2005-2010):
120.6 MW (#3)

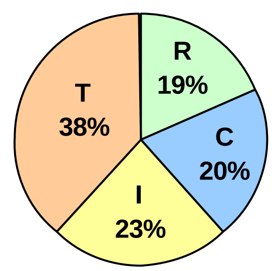
Average Capacity per Site (2005-2010):
0.9 MW

Total Primary Energy Consumption (2008):
8,381 trillion Btu (#2)

Average Gas Price (2009):
$7.87 per MCF (#40)

Average Electricity Price (2010):
14.07¢ per kWh (#9)

Energy Consumption by Sector



The CHP market in California, relative to other states, is very favorable. However, there are still many barriers to development and opportunities to improve the market environment. The state received a maximum score for CHP in ACEEE's 2010 *Scorecard*. Between 2005 and 2010, California installed 140 new CHP systems with a combined capacity of 120.6 MW.

With high electric rates, CHP and other forms of distributed generation are more economically attractive than in other parts of the country. Even so, the recent volatility of gas prices has made some developers hesitant to move forward with projects. Additionally, challenges with accessing upfront capital have been exacerbated by the current economic downturn.

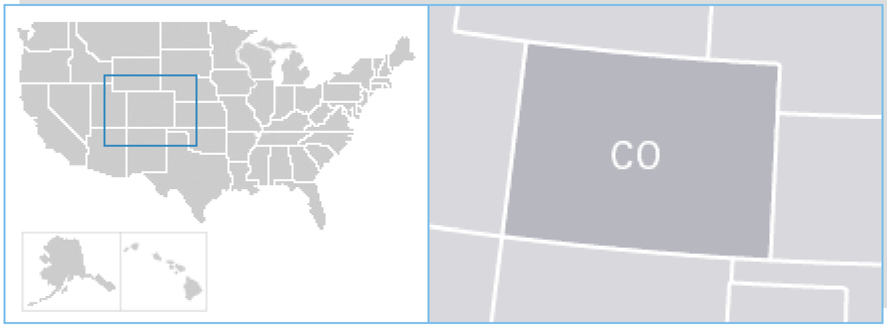
While electricity sales in California are decoupled from revenue for IOUs and performance incentives are in place for utilities that meet energy efficiency goals, there is still some level of resistance among some utilities. Supporters cited some of the state's municipal utilities as the easiest to work with, despite their generally lower electricity rates. One stakeholder described the practice of utilities offering lower electricity prices to customers considering CHP as widespread, negatively impacting some projects economics.

Interconnecting a system with the grid in California can be a hassle, though not a project killer. The Rule 21 process has improved interconnection procedures significantly since its inception in 2000. Utility standby rates, though, reportedly pose unnecessary costs to CHP customers, and could worsen as exemptions from high rates expire.

California is well known for its stringent air emission standards. Developers across the country tended to compare their own states' emissions laws with California's, what seems to be the gold standard of tight regulations. These laws, which limit the amount of emissions per unit of energy produced, make smaller projects much more difficult, but have less of an impact on larger projects. Compliance costs for permitting and emissions controls tend to comprise a significant portion of the upfront cost of a project.

Uncertainty about the future of regulations and incentives also plays a role in stymieing CHP development. Developers know that there are new incentives coming down the pipeline, but without certainty of what they will be, many are putting projects on hold. Once final rules are decided for the state's feed-in tariff as well as its finalized carbon dioxide mitigation scheme, there will be more certainty in the market and likely an increase in development.

COLORADO



New CHP Sites (2005-2010):
9 sites (#11)

New CHP Capacity (2005-2010):
10.7 MW (#26)

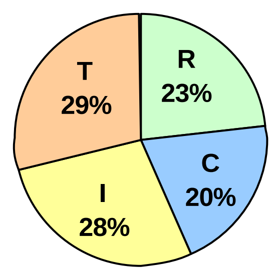
Average Capacity per Site (2005-2010):
1.2 MW

Total Primary Energy Consumption (2008):
1,498 trillion Btu (#25)

Average Gas Price (2009):
$8.12 per MCF* (#38)

Average Electricity Price (2010):
9.34¢ per kWh (#22)

Energy Consumption by Sector



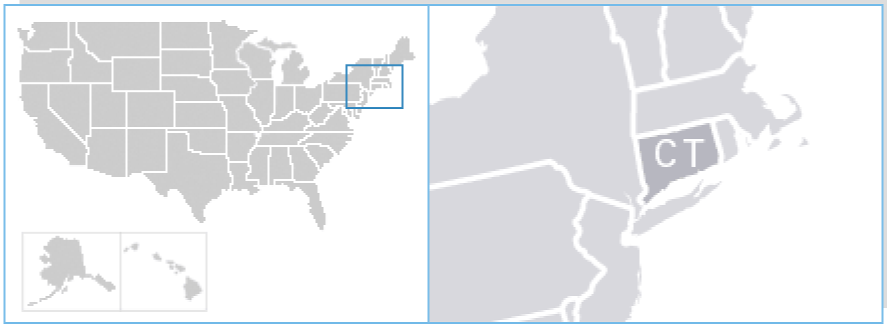
The CHP market in Colorado is somewhat favorable. The state received four out of five possible points for its CHP score in ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Colorado installed 9 new CHP systems with a combined capacity of 10.7 MW.

Stakeholders in Colorado cite utilities as the largest stumbling block to CHP development. Utilities are not currently interested in having CHP as part of their portfolio, and are averse to the revenue loss associated with non-utility generation. While some municipal utilities are amenable or even attracted to including CHP in their portfolios, most public utilities in Colorado generate very little of their own power—buying most of it from IOUs or generation and transmission entities—so there is very little utility-sanctioned CHP in the state.

Despite Colorado having passed a fairly strong interconnection standard in 2005, utility interconnection practices were still cited as a major barrier to CHP. One developer suggested utilities in Colorado are averse to including CHP in their portfolios, and that they make the interconnection process more difficult than it should be and charge unreasonable fees. For example, a recent project at a hospital in Xcel Energy territory was killed due to the standby rate structure it faced.

As in other states, a lack of knowledge among key players has been a barrier in Colorado. The state has taken major strides over the past several years in energy efficiency and renewable energy, but CHP remains an often-disregarded solution to many of the same energy issues. There is inadequate understanding within the PUC and among the general public of the benefits of CHP. However, CHP developers in Colorado are generally confident that the next few years will see an increase in development. With recent utility commitments to begin phasing out coal power plants, stakeholders are hopeful that there will be renewed utility interest in CHP, and therefore fewer barriers to deployment.

CONNECTICUT



New CHP Sites (2005-2010):
62 sites (#3)

New CHP Capacity (2005-2010):
186.4 MW (#2)

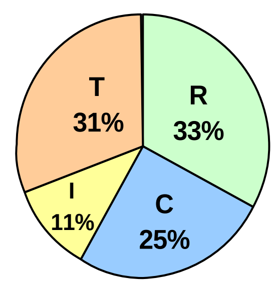
Average Capacity per Site (2005-2010):
3 MW

Total Primary Energy Consumption (2008):
810 trillion Btu (#34)

Average Gas Price (2009):
$11.06 per MCF (#22)

Average Electricity Price (2010):
17.44¢ per kWh (#2)

Energy Consumption by Sector



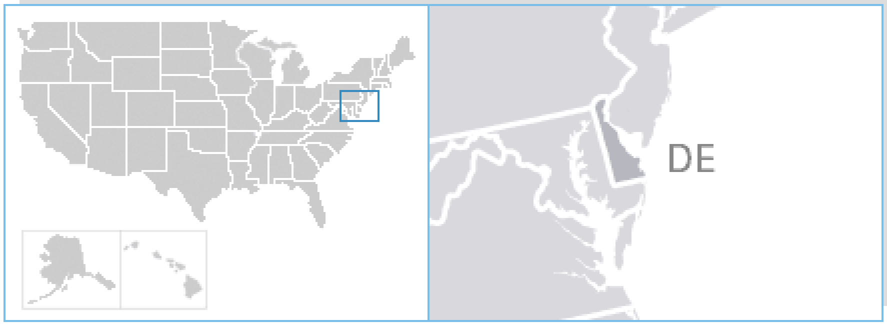
The CHP market in Connecticut is very active. The state received the maximum score in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Connecticut installed 62 new CHP systems with a combined capacity of 186.4 MW. Connecticut has some of the most expensive electricity rates in the country, which makes the spark spread there relatively favorable to CHP. However, many barriers remain to CHP's widespread deployment, and opportunities still exist to further encourage development.

Access to capital is a major challenge for CHP developers and customers. With an aversion to risk and extensive payback periods among businesses and a reluctance to lend among the banking community, it has been difficult for potential hosts to secure the finances for project development. Connecticut currently has some policy mechanisms that encourage CHP and other distributed generation, such as the energy improvement districts outlined in Public Act 07-242, *An Act Concerning Electric and Energy Efficiency,* and the slew of energy efficiency provisions in Public Act 05-1, *An Act Concerning Energy Independence.* But while utilities receive a 1—8% performance fee for administering the energy efficiency programs, CHP is not currently included in this fee.

Supporters in Connecticut argue that by making the utilities a part of the process, with an established incentive to move projects along and the ability to profit from projects, there will be a much higher rate of market penetration. Currently, market forces still push Connecticut utilities to make large investments in transmission lines rather than distributed generation, as they can recover more costs and garner greater profits from such investments. Because utilities cannot financially benefit from CHP, they are more likely to resist its implementation.

While a large amount of CHP has come online in Connecticut since the passage of Public Act 05-1 in 2005, many of the new systems that took advantage of the bill's incentives are, in fact, used as backup generators, which do much less to provide energy, economic, and security benefits than active CHP typically provides. These backup generators ultimately exhausted much of the incentive funding for the program, and the program was not renewed. However, it did help to meet its intended goals, as much of the impetus for the provisions in Public Act 05-1 was the congestion problems in the southwestern region of the state. More education will be required for legislators and regulators to make the case that CHP and distributed generation can provide many other benefits outside of helping to prevent blackouts.

DELAWARE



New CHP Sites (2005-2010):
0 sites (#45)

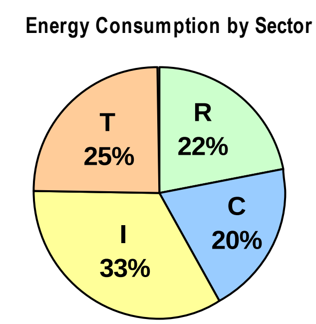
New CHP Capacity (2005-2010):
0 MW (#45)

Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
295 trillion Btu (#47)

Average Gas Price (2009):
$15.75 per MCF (#3)

Average Electricity Price (2010):
11.99¢ per kWh (#14)

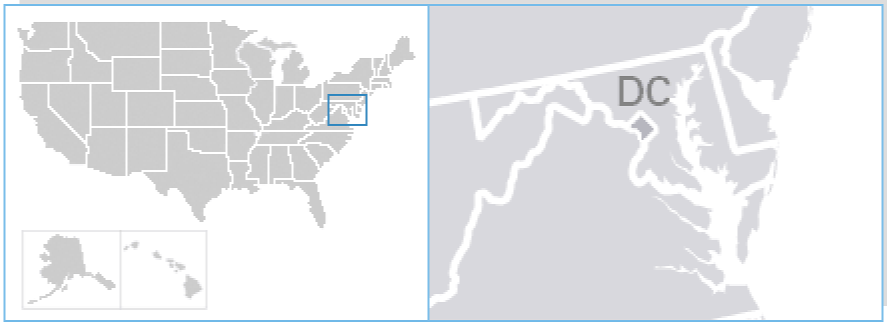


The CHP market in Delaware is not favorable and has seen very little activity recently. The state scored three out of a possible five points in ACEEE's *Scorecard*, and has seen no new CHP installations between 2005 and 2010. The last CHP project installed in the state was in 1985.

No barriers were identified in Delaware by developers, in part due to the fact that no new projects appear to have been considered recently. CHP appeared to be an unfamiliar energy resource to the Delaware energy policymakers who were contacted.

Many of the large utility-owned power plants in the state are cogeneration units, but the state does not have many operational facility-level CHP projects. Delaware has relatively high electric rates, which would suggest that an economic case for CHP could be made in certain applications.

DISTRICT OF COLUMBIA



New CHP Sites (2005-2010):
0 sites (#45)

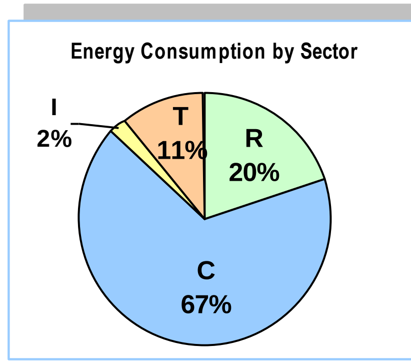
New CHP Capacity (2005-2010):
0 MW (#45)

Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
180 trillion Btu (#50)

Average Gas Price (2009):
$13.98 per MCF‡ (#6)

Average Electricity Price (2010):
13.84¢ per kWh (#10)

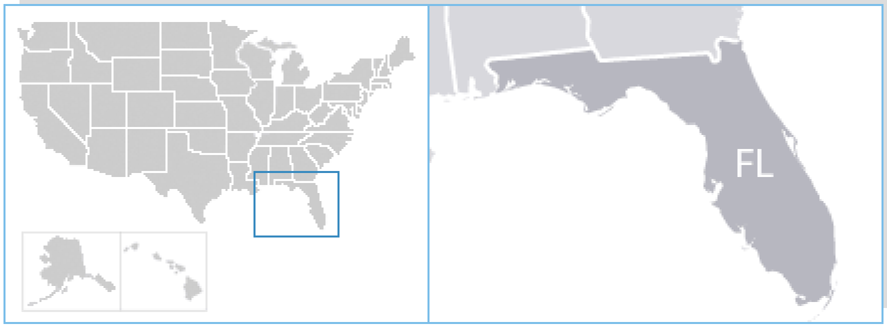


The CHP market in the District of Columbia is small and has historically not been very active. Between 2005 and 2010, no new CHP projects were installed. However, new federal mandates to reduce greenhouse gas emissions from government buildings has helped usher in a new interest in CHP in the District, where federal government buildings make up a large percentage of the built environment. A district energy system in the Capital Hill neighborhood that would use the area's existing steam system is in the works, leveraging federal stimulus funds.

In ACEEE's 2010 *Scorecard*, the District scored four out of five possible points. It recently adopted new interconnection standards, and its biggest investor-owned utility, PEPCO, offers standby rates that are viewed as favorable toward CHP. Net metering policies, which apply to systems under 1 MW, can be used to net meter smaller CHP projects.

The District appears to be at a turning point for distributed generation, and local regulators and supporters view it as an up-and-coming environment for CHP.

Florida



New CHP Sites (2005-2010):
3 sites (#26)

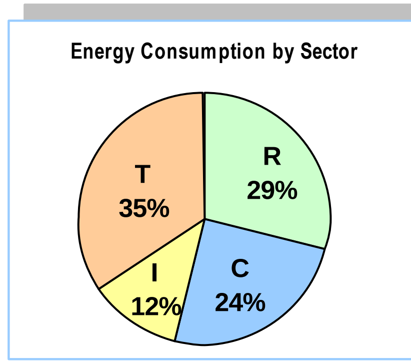
New CHP Capacity (2005-2010):
43.9 MW (#12)

Average Capacity per Site (2005-2010):
14.6 MW

Total Primary Energy Consumption (2008):
4,447 trillion Btu (#3)

Average Gas Price (2009):
$11.02 per MCF[ℓ] (#24)

Average Electricity Price (2010):
10.57¢ per kWh (#15)



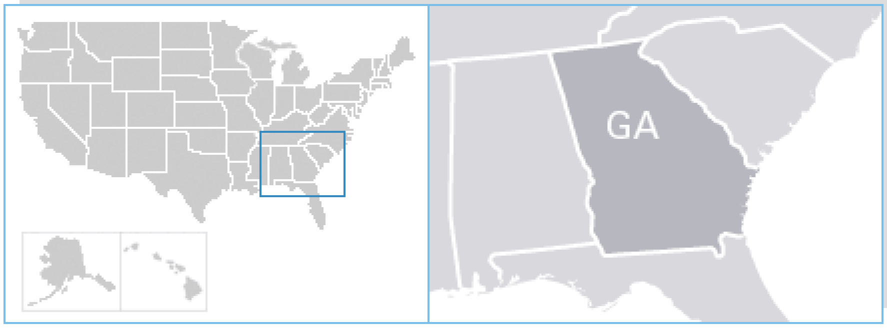
The CHP market in Florida is not favorable. The state received three points out of a possible five in ACEEE's *Scorecard*, and has seen the installation of three new CHP systems between 2005 and 2010. These installations represent a combined installed capacity of about 44 MW.

The primary barriers to greater CHP deployment in Florida are economic and regulatory ones. "The economics are not really there" in the state, as there is little heating load in many potential markets. Facilities that have high demand for hot water, such as hospitals, hotels, and dormitories, are sometimes the best candidates for CHP in Florida. Florida electricity prices are not high enough to present a favorable spark spread. Some incentive money is available for CHP, including a renewable energy production tax credit that waste heat projects may take advantage of.

Regulatory hurdles are substantial in Florida and have served to "dampen" the market for CHP considerably. The biggest hurdle is a statutory law prohibiting the retail sale of electricity in the state by any generator that is not a utility company. This law can be overcome by becoming a PURPA QF, but the avoided cost payments in Florida are extremely low, making such projects very unattractive. A generator of power must also have the exact same corporate identity as the recipient of power—preventing entities that share a building from sharing power generated by a CHP system. This law has been very detrimental to the CHP market in Florida, and has prevented the application and deployment of many CHP systems throughout the state.

Over the past several years, a governor-led Climate Action Team was tasked with developing recommendations to maximize Florida's energy efficiency potential. Supporters note that these efforts have failed to give much attention to CHP, and these efforts represent "a missed opportunity" for greater CHP deployment in the state. An overarching theme noted by developers was that Florida's Public Service Commission has not been helpful in promoting the cause of CHP in the state. Consequently, Florida's IOUs have not been encouraged and required to move forward programs that would enhance the state's energy efficiency through projects such as CHP. While there is tremendous technical potential in the state, only a small portion of that potential has yet been tapped. Many believe that the political winds of Florida must change—thus changing the goals and plans of the PSC—before the market will really open up for additional CHP.

GEORGIA



New CHP Sites (2005-2010):
4 sites (#19)

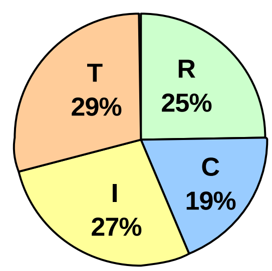
New CHP Capacity (2005-2010):
2.9 MW (#35)

Average Capacity per Site (2005-2010):
0.7 MW

Total Primary Energy Consumption (2008):
3,015 trillion Btu (#9)

Average Gas Price (2009):
$11.86 per MCF (#17)

Average Electricity Price (2010):
9.03¢ per kWh (#25)



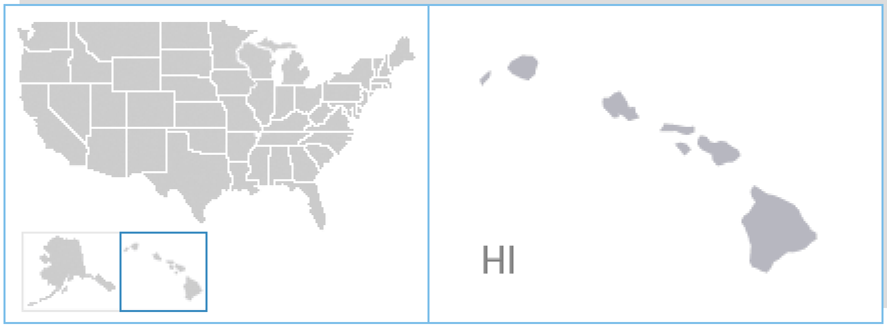
The CHP market in Georgia is unfavorable. The state received zero points out of a possible five in ACEEE's *Scorecard*, and has installed only three new CHP projects between 2005 and 2010, representing almost 3 MW of total installed capacity. Georgia's *Scorecard* score reflects the fact that the state has no policies and no incentives in place that actively encourage CHP.

One of the big barriers to greater CHP deployment in Georgia is economics, which are not aided by the unfavorable standby rates charged by Georgia Power for standby and backup power. Georgia's electricity prices are low, thanks to the state's reliance on coal for over half of its electricity. The spark spread in the state is not good, though industrial companies manufacturing wood products have found it economic to use wood waste products to power some CHP systems. Georgia has no interconnection standard in place, as it chose not to adopt an interconnection standard in response to the Energy Policy Act of 2005.

In addition to the above barriers, air emissions regulations have prevented the deployment of at least one recent project. Georgia has a relatively high number of non-attainment areas, and does not have output-based emissions standards for any criteria pollutants. Recently, one facility was considering replacing two existing boilers with a CHP system, but did not do so because it determined that it would be penalized for the higher localized emissions at the facility site. These emissions regulations barriers exist despite the fact that Georgia's overall emissions would be greatly reduced by CHP.

Georgia has made slow steps towards encouraging greater energy efficiency in the state. In 2010, voters approved Amendment 4, which authorized public agencies to solicit performance contracting agreements for energy efficiency investments and energy conservation efforts. This could potentially open the door to CHP projects at appropriate government facilities in the near future.

HAWAII



New CHP Sites (2005-2010):
3 sites (#26)

New CHP Capacity (2005-2010):
1.9 MW (#37)

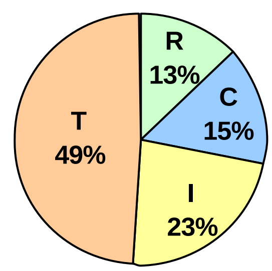
Average Capacity per Site (2005-2010):
0.6 MW

Total Primary Energy Consumption (2008):
284 trillion Btu (#48)

Average Gas Price (2009):
$28.47 per MCF (#1)

Average Electricity Price (2010):
24.91¢ per kWh (#1)

Energy Consumption by Sector



The CHP market in Hawaii is not very active. The state received three out of five possible points for its CHP score in ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Hawaii installed only 3 new CHP systems with a combined capacity of 1.9 MW.

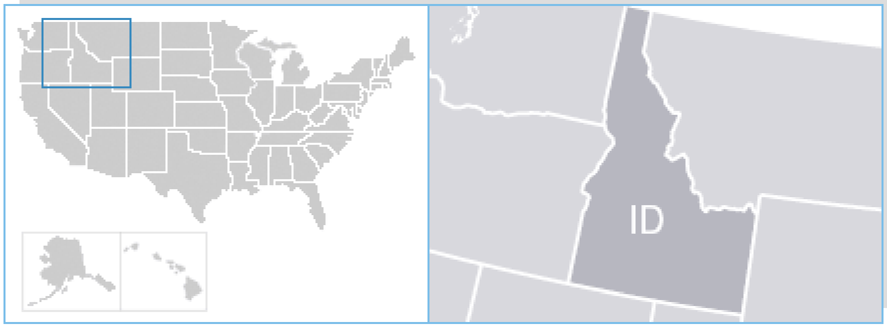
Hawaii has by far the most expensive electricity in the U.S. Because of this and the isolated nature of electricity grids in the state, it would be logical for distributed generation such as CHP to pervade the market. However, CHP has not been as abundant as one might expect it to be. A large factor contributing to the dearth of projects is the lack of access to cheap natural gas. The state's islanded geography has also precluded the construction of an extensive gas distribution network. Gas in Hawaii is largely limited to the area around Honolulu; CHP projects elsewhere tend to be exploring opportunities in liquefied petroleum gas (LPG) and biomass as fuel sources.

The recent lack of CHP projects can be attributed in part to a lack of easily accessible fuel, but other factors play a role as well. Utilities in Hawaii are extremely interested in keeping electricity customers in what is already a very small pool. One CHP advocate working in Hawaii described the electric utilities IOUs there as "very antagonistic." He noted that they "want to interject notions of risk into clients' minds." While Hawaii's interconnection protocols help to prevent IOUs from dragging their feet for too long, they are still able to argue for protracted studies of technical issues and potential risks. This adds cost to projects, and while such studies are sometimes valid, they are sometimes drawn out to an unreasonable or unnecessary extent.

One stakeholder in Hawaii expressed concern that there is a fair amount of corruption among Hawaii IOUs. Utilities have tried to levy exorbitant standby charges to prevent CHP from being installed, and with such a small electricity network, they know all their customer loads intimately and it is easy for them to manipulate rates.

Recently, Hawaii has made a very strong push for increased renewable electricity generation. In 2004, Senate Bill 2474 expanded the state's existing renewable portfolio standard to include "electric energy savings brought about by the use of energy efficiency technologies," which includes CHP (DSIRE 2010). The most recent amendments to the RPS passed in the summer of 2009 and require 40% of Hawaii's electricity to be generated from renewable sources by 2030. It is unclear what kind of impact this will have on CHP development in Hawaii, but supporters remain optimistic.

IDAHO



New CHP Sites (2005-2010):
2 sites (#34)

New CHP Capacity (2005-2010):
3.8 MW (#32)

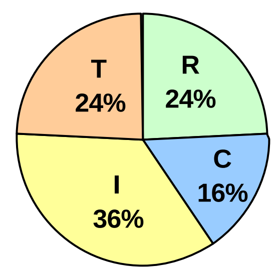
Average Capacity per Site (2005-2010):
1.9 MW

Total Primary Energy Consumption (2008):
529 trillion Btu (#41)

Average Gas Price (2009):
$10.28 per MCF* (#27)

Average Electricity Price (2010):
6.57¢ per kWh (#49)

Energy Consumption by Sector



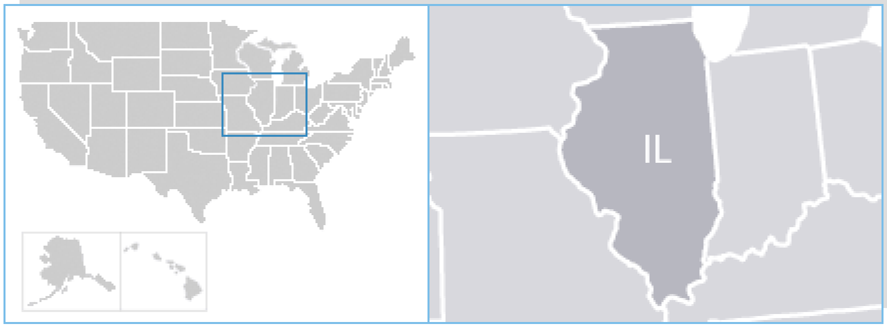
The CHP market in Idaho is not a very active one and is less favorable than other markets in the West. Idaho earned two points of a possible five in ACEEE's 2010 *Scorecard*, a reflection of few in-place regulations designed explicitly to support CHP projects.

Two CHP projects have been installed since 2000. Both are located at dairies and biomass-powered. Biomass represents an opportunity in the state, due to the large wood products and food processing industries. However, the state does not have a renewable energy or energy efficiency portfolio standard, and the state's heavy reliance on hydropower yields very cheap electric rates that can make it hard to justify distributed energy projects of all stripes.

In Idaho, projects under 10 MW can qualify to become Qualified Facilities, thus receiving PURPA avoided cost rates. The state's avoided cost rates are quite high, and projects in surrounding states have sold into the Idaho power market to take advantage of the high rates. But even with the high avoided cost rates, projects still suffer from such low electric rates. Financing has also been hard to come by, as have appropriate feed stocks for certain projects.

Interconnection also remains a barrier in Idaho. It was one of the states that chose not to adopt new interconnection standards in response to the federal Energy Policy Act of 2005, and it has left interconnection unregulated for years. Each investor-owned utility has developed its own interconnection process, but regulators in the state have begun to realize that consumers would benefit from a more standard process across all service areas. A recent workshop addressed the fact that the interconnection process can be complicated and costly, especially for smaller projects, and it appears that many of the state's utilities are prepared to make some compromises to usher in a new interconnection standard.

ILLINOIS



New CHP Sites (2005-2010):
9 sites (#11)

New CHP Capacity (2005-2010):
104.8 MW (#4)

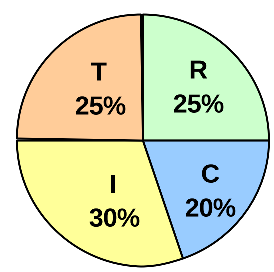
Average Capacity per Site (2005-2010):
11.6 MW

Total Primary Energy Consumption (2008):
4,089 trillion Btu (#4)

Average Gas Price (2009):
$8.34 per MCF (#37)

Average Electricity Price (2010):
9.23¢ per kWh (#23)

Energy Consumption by Sector



The CHP market in Illinois is generally favorable. The state received a maximum score in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Illinois installed nine new CHP systems with a combined capacity of 104.8 MW.

According to stakeholders, twenty years ago, the cost of gas and the electric rate structure made CHP and other forms of distributed generation a sound investment for a mid- to large-size business. Unstable gas prices and less favorable electric rate structures—due to electric deregulation in 2007—have damaged the market for natural gas-fueled CHP projects in Illinois. Gas prices are still one of the major factors influencing demand for CHP in Illinois. Interest in CHP has decreased considerably since the spike in natural gas prices in 2002. When potential payback on installed CHP systems went from three or four years to 10 or more, demand disappeared. Even though gas prices have recently fallen into a more acceptable range, the volatility of the past has created hesitation among consumers.

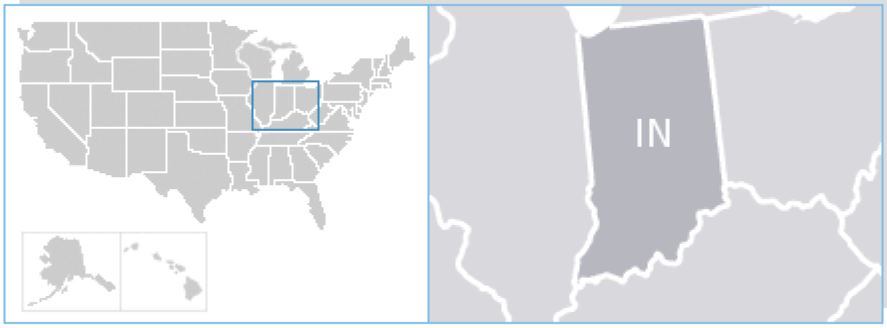
Other factors have played a role in the Illinois market as well. Several years ago, northern Illinois's largest investor-owned utility, ComEd, had a rate structure in place provided acceptable economics for CHP projects. In recent years, however, the rate structure has changed, requiring CHP owners to operate longer hours and at reduced savings if they maintain full service from ComEd. CHP owners also have the option to shop other electric providers for more favorable rates when operating CHP systems, often with shorter operating hours. Those who already owned a system could benefit from the marginal savings still available, but developers looking to invest in CHP were faced with 1) longer running hours, which meant increased maintenance costs and operator costs, translating to decreased savings, or 2) shorter operating hours, thereby reducing the overall savings opportunities.

Historically, the cost and complexity of interconnection with the utility has impeded project development in Illinois, with utilities making onerous requirements of CHP owners. However, a final interconnection standard was adopted by the Illinois Commerce Commission in March 2010, and developers hope it will mitigate many of these issues.

Permitting for emissions has also historically created a considerable hassle, though not an insurmountable hurdle. However, new regulations that went into effect in 2009 and 2010 establish CHP as an eligible technology for energy efficiency set-aside allowance and factor output into the determination of a system's overall emissions.

Along with other states in the Midwest, there has been an increased interest in CHP technologies utilizing renewable biogas fuels (e.g., farms, food processing facilities, and wastewater treatment facilities). Over the past several years the Illinois Department of Commerce and Economic Opportunity has offered grant incentives for biogas and biomass CHP projects.

INDIANA



New CHP Sites (2005-2010):
8 sites (#14)

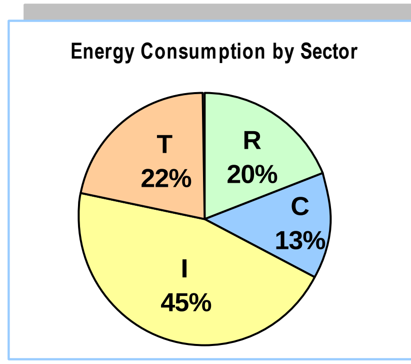
New CHP Capacity (2005-2010):
2.2 MW (#36)

Average Capacity per Site (2005-2010):
0.3 MW

Total Primary Energy Consumption (2008):
2,857 trillion Btu (#11)

Average Gas Price (2009):
$8.76 per MCF (#34)

Average Electricity Price (2010):
7.66¢ per kWh (#40)



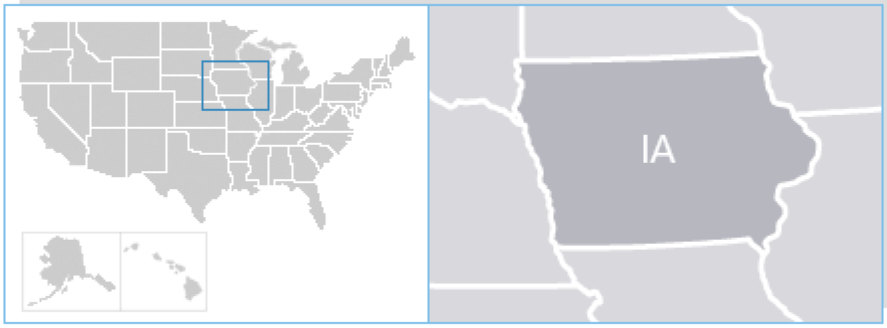
With regard to CHP development, Indiana is somewhat of an anomaly. The state received three out of five points in the CHP chapter of ACEEE's 2010 *Scorecard*. Despite having a moderately favorable regulatory environment, however, eight new systems were installed between 2005 and 2010, with a combined capacity of only 2.2 MW.

Indiana has not taken great strides for specific policies that will make CHP more attractive simply because the market in the state is a question of economics more than anything else. Electricity is extremely inexpensive in Indiana, so an economically viable opportunity is hard to find. In fact, Indiana boasts its low electricity rates in the context of clout for economic development for businesses and residents. With more than half the state's total energy use drawing from coal sources, Indiana has been emphasizing renewable energy sources as the prime clean energy target. From a CHP standpoint, interest in Indiana has centered largely on biogas applications from food processing, wastewater treatment, and animal waste through the use of anaerobic digesters. However, it has been difficult for alternative sources to gain traction in the state. According to one developer with experience in Indiana, "CHP is not something customers will jump on unless they happen to be interested in CHP or emissions reductions."

Developers in Indiana have not run into utilities as a major obstacle. They are fairly easy to get along with in the development process. The interconnection process has not been very difficult historically, and the regulatory commissioners are "fairly reasonable people," according to one Indiana stakeholder.

Outside of sheer economics, the obstacle to CHP in Indiana seems to be a lack of awareness of the benefits and potential of such applications. There is a great deal of potential for CHP at institutions in Indiana, especially where administrators and students have committed to reducing energy consumption or greenhouse gas emissions, and awareness about CHP is growing in universities around the state. But in the end, projects still come down to economics before anything else, and few firms are finding investments in CHP viable at this time.

IOWA



New CHP Sites (2005-2010):
3 sites (#26)

New CHP Capacity (2005-2010):
16.9 MW (#19)

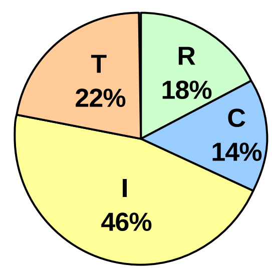
Average Capacity per Site (2005-2010):
5.6 MW

Total Primary Energy Consumption (2008):
1,414 trillion Btu (#28)

Average Gas Price (2009):
$7.88 per MCF (#39)

Average Electricity Price (2010):
7.77¢ per kWh (#37)

Energy Consumption by Sector



The CHP market in Iowa is not very favorable. The state received a score of two out of five in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Iowa installed three new CHP systems with a combined capacity of 16.9 MW.

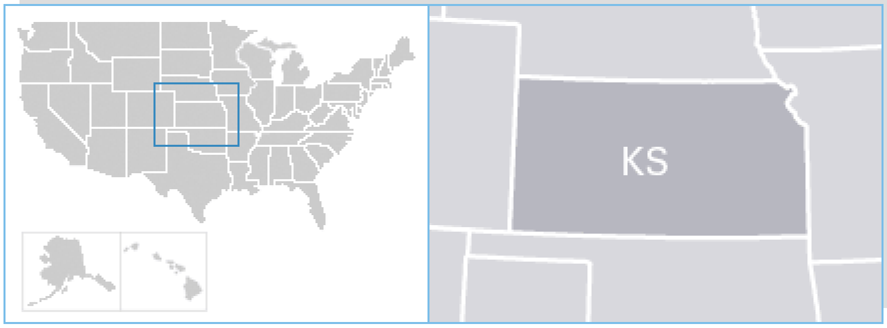
Iowa's *Scorecard* CHP score increased from one in 2009 to two in 2010 with the state's adoption of a new interconnection standard. However, according to developers of CHP in Iowa, interconnection has not historically been a great barrier to project implementation. The biggest issue that CHP stakeholders point to is the state's spark spread; because of the significantly low electricity prices, it is hard to economically justify projects with high upfront costs and high payback periods.

In addition to its unfavorable spark spread, all four of Iowa's IOUs employ standby rates that actively discourage CHP investment. These rates are largely demand based and exclude backup and maintenance generation exemptions. Since the majority of Iowa's utilities include a year-long peak demand ratchet, the increased demand caused by regular scheduled maintenance exhausts much of the potential financial savings created by CHP.

Very little natural gas-fired CHP has come online in Iowa in the past several years. New projects in the state are typically using biofuels, while some applications are coal-fueled. A majority of CHP in Iowa is used for agriculture, food processing, and wastewater treatment applications, where an onsite fuel source is typically available and relatively easy to harness. As new projects are proposed and undertaken, this trend seems to be continuing.

Iowa does not offer financial incentives to CHP systems to increase deployment. One Iowa developer bemoaned the fact that the state's legislators and regulators focus their efforts on wind power development, providing relatively generous tax incentives for such generators but largely ignoring the environmental and energy benefits of CHP. The developer noted that in Iowa, CHP is not considered "renewable enough." Despite favorable green electricity rates established by the Iowa Utilities Board for certain electricity resources, CHP does not receive the same treatment. The lack of awareness among politicians and regulators makes it even harder for CHP to move beyond the economic analysis stage toward implementation; access to capital is a huge issue in Iowa and a lack of grants, low interest loans, and tax incentives of any kind make obtaining capital very difficult.

KANSAS



New CHP Sites (2005-2010):
4 sites (#19)

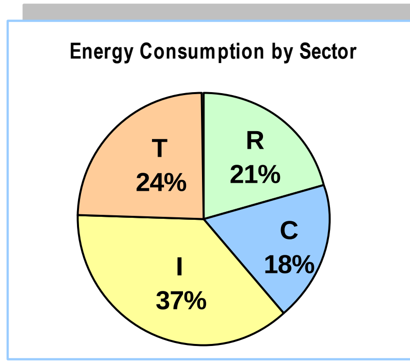
New CHP Capacity (2005-2010):
16.0 MW (#21)

Average Capacity per Site (2005-2010):
4 MW

Total Primary Energy Consumption (2008):
1,136 trillion Btu (#30)

Average Gas Price (2009):
$8.50 per MCF (#36)

Average Electricity Price (2010):
8.29¢ per kWh (#34)



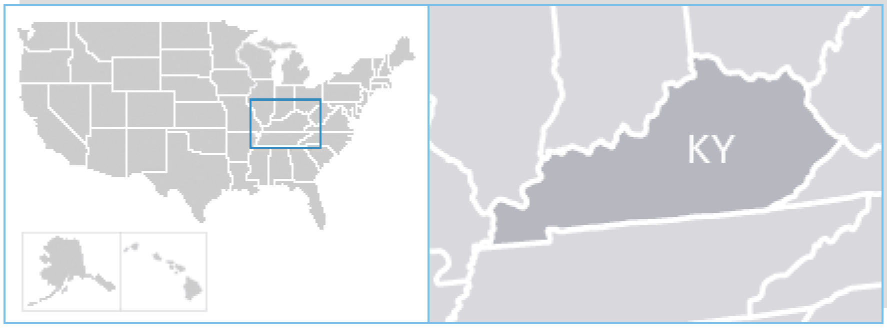
The market for CHP in Kansas is not favorable. The state earned the lowest possible score in ACEEE's *Scorecard*, and has seen the installation of three new CHP projects between 2005 and 2010, representing 12 MW of installed capacity.

Economics and utility incentives are the prime barriers to greater CHP project deployment in Kansas. In the few instances where CHP has made sense, it has been the will of private industry to make projects happen. The industrial sector has been Kansas' historic sweet spot for CHP, and, more recently, the ethanol industry in particular has made several CHP investments. Kansas boasts tremendous natural gas reserves, consumes most of it in-state, and has some of the cheapest natural gas prices in the country. Consequently, almost all of Kansas' in-place CHP projects are natural gas-powered. However, even Kansas' cheap natural gas does not provide good enough spark spreads to make projects happen.

Kansas' utilities are not active in the CHP market and have no real incentive to be. An in-place RPS does allow biomass facilities to count as an eligible resource, but does not credit waste heat generally as a renewable resource. There are no specific energy efficiency goals that regulated utilities in the state need to meet. Supporters believe that until there is some in-place mandated efficiency goal, utilities will not be interested in CHP.

The economics that disfavor CHP are not helped by unfavorable standby rate offerings from the state's two biggest utilities. The state also does not offer any incentives for CHP. Until there is a more concerted effort to deploy CHP in the state, it appears that Kansas's CHP market will remain fairly unfavorable.

KENTUCKY



New CHP Sites (2005-2010):
0 sites (#45)

New CHP Capacity (2005-2010):
0 MW (#45)

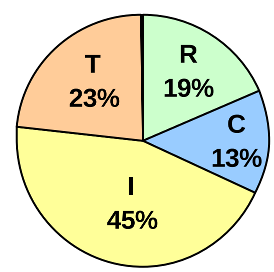
Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
1,983 trillion Btu (#18)

Average Gas Price (2009):
$9.51 per MCF (#31)

Average Electricity Price (2010):
6.71¢ per kWh (#48)

Energy Consumption by Sector

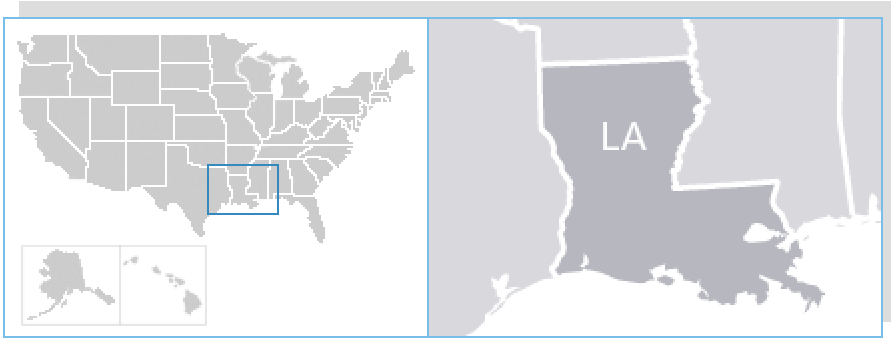


The market for CHP in Kentucky is not favorable. The state earned zero points out of a possible five in ACEEE's *Scorecard* and has installed no new CHP projects between 2005 and 2010.

The primary barrier to greater CHP deployment in Kentucky is economics. The state has an unfavorable spark spread, due primarily to an abundance of cheap coal-powered electricity. The wood products industry is the main industry that has found it economic to invest in CHP, largely due to the ample wood-based fuel resources their production processes provide.

At the moment, Kentucky utilities are not well incentivized to pursue CHP at customer facilities. However, a 2010 bill, H.B. 240, provides the Kentucky Public Service Commission with the ability to require that regulated utilities deploy DSM programs. Duke Energy and AEP have the ability to earn some incentive for deploying efficiency, though it does not appear that these utility incentives have yet led to greater CHP deployment.

LOUISIANA



New CHP Sites (2005-2010):
0 sites (#45)

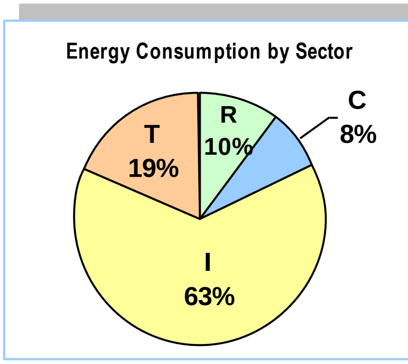
New CHP Capacity (2005-2010):
0 MW (#45)

Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
3,488 trillion Btu (#8)

Average Gas Price (2009):
$8.76 per MCF**(#35)

Average Electricity Price (2010):
7.85¢ per kWh (#36)



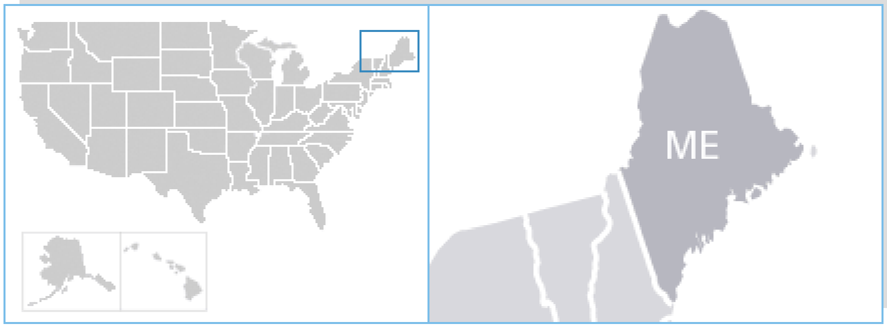
The CHP market in Louisiana is not favorable. The state received a score of zero out of five in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Louisiana installed no new CHP systems.

Louisiana is well known for its abundance of industry, and in fact has over 6,700 MW of CHP installed throughout the state, primarily at chemicals, refining, food processing, and pulp and paper facilities. However, the last CHP system in Louisiana went into operation in 2004, and the vast majority of systems were installed over 20 or 30 years ago.

The current regulatory climate for CHP in Louisiana is one of the worst in the country. None of the CHP-friendly regulatory policies assessed in ACEEE's *Scorecard* are employed in the state, and Entergy, the largest IOU there, incurs standby rates on CHP customers that are widely viewed as unreasonable. Louisiana is, however, in the final stages of establishing a renewable portfolio standard for its IOUs—currently just a pilot program—in which CHP supporters are attempting to include CHP as a subset of waste heat recovery, an eligible resource under the standard. Still, in the current language, credit cannot be earned for capturing waste heat and using it for purposes other than electricity generation.

According to stakeholders, the biggest obstacle to CHP in Louisiana is still Entergy. The utility, which has an inherent disincentive to allow other electricity resources to compete for sales, reportedly makes the interconnection process more difficult and costly than it needs to be. Additionally, it often requires Ratepayer Impact Measure (RIM) tests to ensure that new loads will not adversely affect ratepayers. Employing these and other strategies, Entergy is able to keep many projects from moving beyond the drawing board.

MAINE



New CHP Sites (2005-2010):
2 sites (#34)

New CHP Capacity (2005-2010):
4.5 MW (#31)

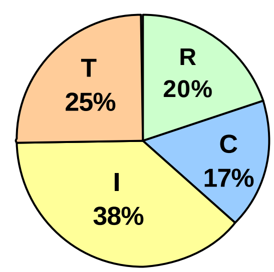
Average Capacity per Site (2005-2010):
2.2 MW

Total Primary Energy Consumption (2008):
469 trillion Btu (#42)

Average Gas Price (2009):
$14.35 per MCF (#5)

Average Electricity Price (2010):
12.73¢ per kWh (#13)

Energy Consumption by Sector



With regard to CHP development, Maine is an anomaly of sorts. The state received four out of five points in the CHP chapter of ACEEE's 2010 *Scorecard*. Despite having a relatively favorable regulatory environment, however, only two new systems were installed between 2005 and 2010, with a combined capacity of 4.5 MW.

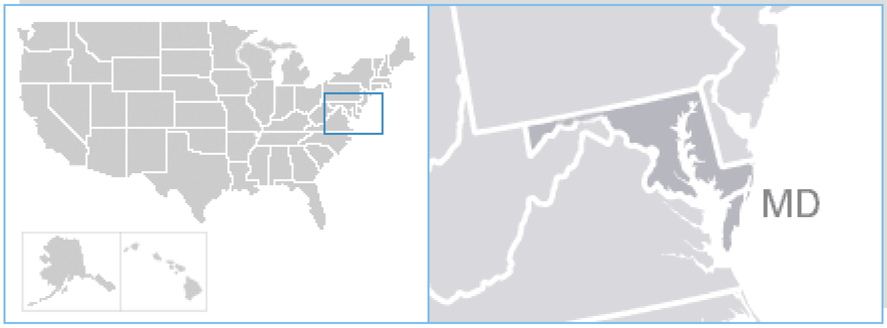
Maine has fairly high electricity rates, which would normally mean that CHP is economical and an easily justifiable investment; however, one of the biggest barriers to CHP in the state is the relative unavailability of natural gas. With approximately 80% of Maine's homes heated by oil and only 4% heated by gas, the state does not have as expansive a gas distribution network as most states (EIA 2010d), so the suitability of applications for CHP is narrower. A concerted expansion of Maine's gas distribution capacity would likely bolster the CHP market significantly.

There are biomass opportunities in Maine, but these systems typically have to be very large—over 15 to 20 MW—to work economically. Sourcing biomass can also be a challenge, with large paper mills competing for resources, but biomass applications can qualify for renewable energy credits, which helps to make them financially viable.

Stakeholders in Maine have indicated that electric utilities do not present insurmountable barriers, but do make projects more difficult. Interconnection fees are generally perceived as necessary costs with predictable procedures, but, as one Maine CHP advocate noted, "Everyone is a little cagey about the process; no one wants to get too far into the details. If a utility wants to play dirty tricks, there are a lot of loopholes that are hard to quantify." Utilities in Maine have reduced rates to firms considering cogeneration systems in order to dissuade them from moving forward with a project.

Even with good payback thresholds, upfront capital costs—often in the tens of millions of dollars—pose one of the biggest barriers to projects in the private sector. The barrier of upfront capital costs are exacerbated by a lack of understanding of the technology among corporate and financial leaders. The current economic downturn in particular has suppressed development. Some funds from ARRA and RGGI have recently been awarded to CHP projects, all of which have yet to be commissioned. Generally, stakeholders in Maine are optimistic that CHP will see an increase in development in the coming years.

MARYLAND



New CHP Sites (2005-2010):
2 sites (#34)

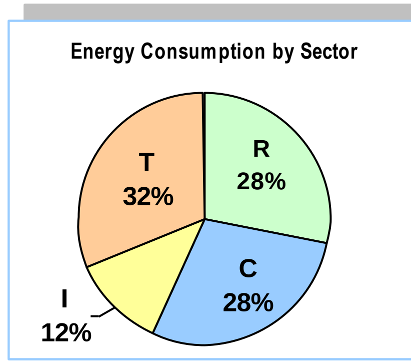
New CHP Capacity (2005-2010):
7.0 MW (#28)

Average Capacity per Site (2005-2010):
3.5 MW

Total Primary Energy Consumption (2008):
1,447 trillion Btu (#27)

Average Gas Price (2009):
$11.86 per MCF (#16)

Average Electricity Price (2010):
12.84¢ per kWh (#12)



The CHP market in Maryland is a growing one, with at least ten new CHP projects installed since 2000. The state received three out of a possible five in ACEEE's 2010 *Scorecard*, reflecting several regulations explicitly supporting CHP.

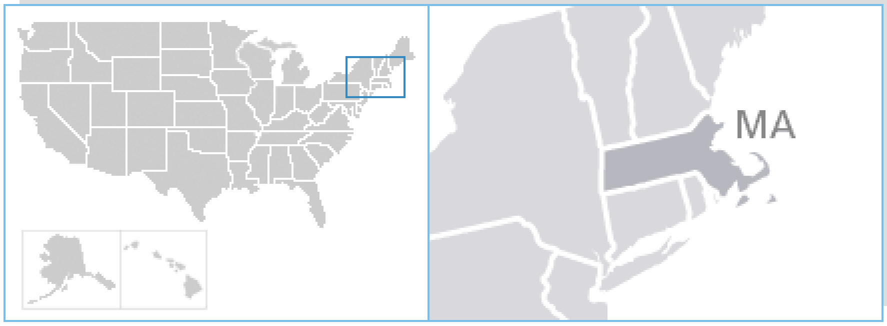
Though Maryland has not been traditionally viewed as a hotbed for CHP activity, developers and supporters expect the Maryland market to improve in the near future. This is due in large part to the energy efficiency plans the state's utilities have recently developed in response to stated energy efficiency goals in the state's energy efficiency plan, EmPower Maryland. As the EmPower Maryland plans have matured, more of the state's utilities have decoupled their profits from their sales revenues, which could positively impact utilities' interest in the CHP market.

Since Maryland falls within the PJM Interconnection footprint, facility owners are generally eligible to participate in that regional transmission organization's demand response and forward capacity markets. These options could offer additional incentives to certain CHP projects, especially as PJM works to improve its capacity markets. Maryland does not offer other incentives for CHP, though a renewable energy production tax credit offers a $0.85/kWh state income tax credit for biomass or biogas-fueled CHP.

Interconnection has been an issue in Maryland, but a new interconnection standard, effective 2009, has helped. The state's net metering laws are widely regarded as excellent for the small size bracket they serve, and have helped smaller (under 30 kW) and micro-CHP projects achieve better economic returns. However, both the interconnection standard and the net metering standard could be expanded to better serve CHP installations beyond the current size limits. These size limits were cited as some of the biggest barriers facing larger CHP projects today.

The Marcellus natural gas shale find is expected to exert downward pressure on natural gas prices in the area, which had steadily risen for years prior to the economic downturn. Such a find could help to further encourage natural gas-fired CHP systems in the area and help potential CHP investors become comfortable making long-term plays in natural gas-dependent technology.

MASSACHUSETTS



New CHP Sites (2005-2010):
34 sites (#4)

New CHP Capacity (2005-2010):
41.8 MW (#13)

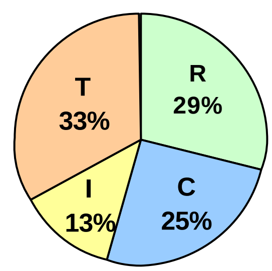
Average Capacity per Site (2005-2010):
1.2 MW

Total Primary Energy Consumption (2008):
1,475 trillion Btu (#26)

Average Gas Price (2009):
$16.81 per MCF** (#2)

Average Electricity Price (2010):
14.65¢ per kWh (#7)

Energy Consumption by Sector



The CHP market in Massachusetts is a generally favorable one. The state received a maximum score in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Massachusetts installed 34 new CHP systems with a combined capacity of 41.8 MW.

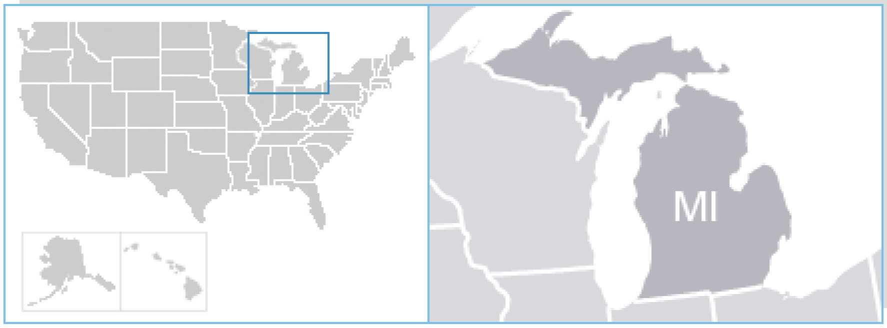
New utility regulations in Massachusetts, including decoupling regulation, regulation requiring "all-cost effective energy efficiency," and an Alternative Energy Portfolio Standard (APS), make CHP much more attractive than in most states. CHP counts as an energy efficiency resource so long as it meets cost-effectiveness thresholds, and with sound decoupling and utility cost recovery policies in place, utilities in Massachusetts are less inclined to resist efficiency and distributed generation. This serves to mitigate and even remove some of the greatest barriers to CHP in the state.

Massachusetts is praised by supporters as having some of the strongest interconnection standards in the country, and interconnection has not presented a significant barrier to development. However, standby rates are reportedly bad in certain areas, especially within NStar service territory, where rates have kept some developers away.

Financial incentives, including the APS and efficiency rebates from the electric utilities, also play a role in encouraging CHP development. The APS, which is a performance-based certificate program, represents approximately $175 per kW per year, depending upon operation efficiencies. Because of its eligibility as an energy efficiency resource, CHP also qualifies for an upfront rebate up to $750 per kW. This helps to keep economic analysis trending favorably toward CHP projects. However, developers report that earning the rebate has been "a cumbersome and costly process," with substantial requirements for studies, monitoring, and other paperwork. They believe the rebate could have a much better impact if it were easier to implement and use, "like the APS program."

In New England, natural gas prices have a direct impact on electricity prices, so spark spread differentials are effectively a temporary result of delays between gas prices and procurements for electricity. State policymakers in Massachusetts believe that incentives have the effect of guaranteeing an improved spark spread, thereby incentivizing more installations. It is anticipated that the market for CHP will be further improved in Massachusetts as developers conduct more aggressive and effective efforts marketing projects to potential hosts.

MICHIGAN



New CHP Sites (2005-2010):
4 sites (#19)

New CHP Capacity (2005-2010):
3.2 MW (#33)

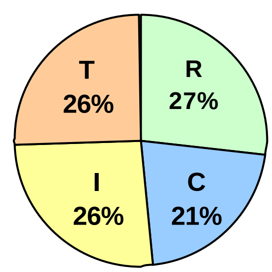
Average Capacity per Site (2005-2010):
0.8 MW

Total Primary Energy Consumption (2008):
2,918 trillion Btu (#10)

Average Gas Price (2009):
$10.14 per MCF (#29)

Average Electricity Price (2010):
10.13¢ per kWh (#17)

Energy Consumption by Sector

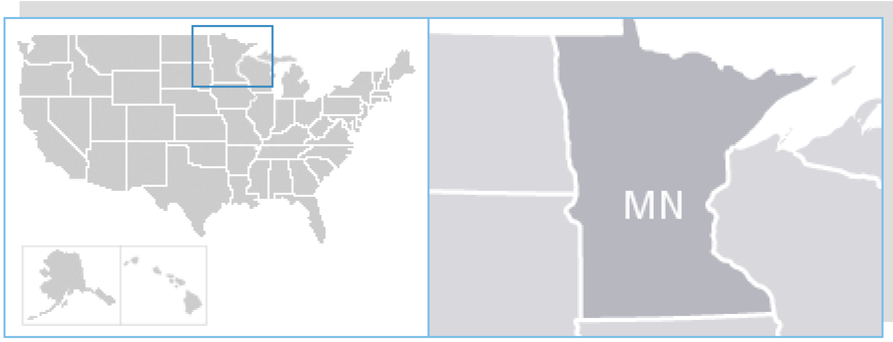


The CHP market in Michigan is not very favorable. The state earned two points out of a possible five in ACEEE's *Scorecard*, and has seen the installation of only three small CHP projects between 2005 and 2010. These projects represent a combined installed capacity of 3.2 MW.

Though the state's somewhat-higher-than-average electricity prices can make the spark spread attractive in some applications, little in dedicated programs and incentives exists for CHP.

Like many other states, Michigan's in-place portfolio standard has not yet reached the year in which the goal set for utilities will be enforced. That does not occur until 2012, when the state's utilities must meet some interim goals on the way to generating 10% of retail electric sales from renewable resources by 2015. Energy efficiency measures are given a particular carve-out in the portfolio standard, but utilities are not fined for failing to achieve the in-place efficiency goals. CHP does explicitly count toward the efficiency goals, however. Developers say this policy does not appear to strongly encourage utilities to pursue CHP at customers' sites at the present time.

MINNESOTA



New CHP Sites (2005-2010):
9 sites (#11)

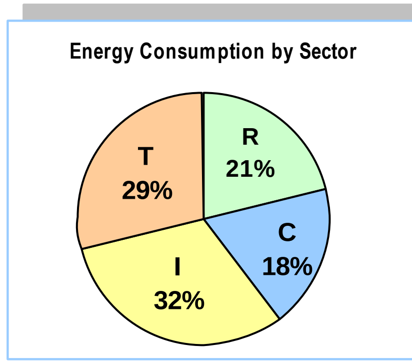
New CHP Capacity (2005-2010):
12.2 MW (#23)

Average Capacity per Site (2005-2010):
1.4 MW

Total Primary Energy Consumption (2008):
1,979 trillion Btu (#19)

Average Gas Price (2009):
$7.52 per MCF (#47)

Average Electricity Price (2010):
8.43¢ per kWh (#33)



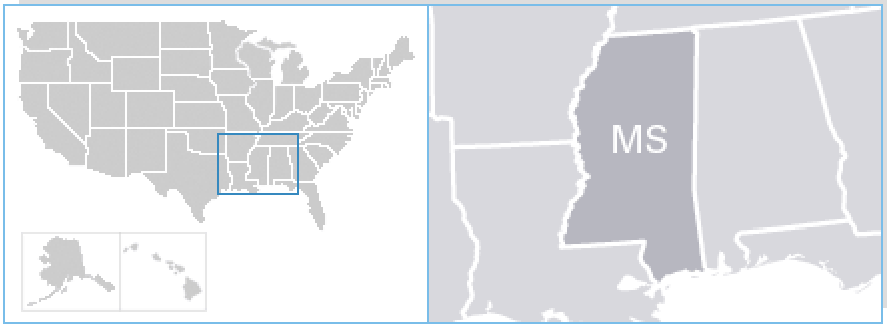
The CHP market in Minnesota is somewhat favorable. The state earned three out of the possible five points in ACEEE's *Scorecard*, and has seen the installation of nine new CHP projects between 2005 and 2010, representing over 12 MW of capacity. The state has taken advantage of biomass in many of these projects, which appear to have made economic sense during the past several years.

Economics have been a big barrier to increased CHP deployment in Minnesota as many companies appear to be waiting to determine just how this economic downturn will affect them, long term. One developer believes that Minnesota does not generally have a business-friendly environment, and that he's seen several companies that would have been good candidates for CHP close down or move out of state in the past several years.

Due to Minnesota's climate, facilities in all sectors tend to have high heating loads, which can lend itself well to CHP. Recent opportunities in the state have been found in the ethanol industry, the institutional sector, and wastewater treatment plants. The City of St. Paul has become well-known for operating the largest hot water district energy system in the country, which relies primarily on a biomass-powered CHP system. Utilities in Minnesota have played a role in encouraging greater energy efficiency, in part due to requirements that they meet RPS goals and specific biomass goals. Two older coal-powered CHP plants were more recently developed into biomass-fueled systems, thanks in part to Xcel Energy's particular need to acquire certain renewable energy resources. A 2007 act, the Next Generation Energy Act of 2007, set energy-saving goals for utilities of 1.5% per year. This and other policies that provide utilities with some incentives for deploying energy efficiency have helped to improve the CHP market in Minnesota.

Though the state offers no specific incentives for CHP, some CHP applications are eligible for renewable energy incentives. In some utility areas, CHP is also eligible for energy efficiency rebates, provided it meets necessary cost-effectiveness tests. It appears that for certain applications, these incentives and the utilities' interest in pursing energy efficiency have combined to create a fairly favorable market for CHP.

MISSISSIPPI



New CHP Sites (2005-2010):
3 sites (#26)

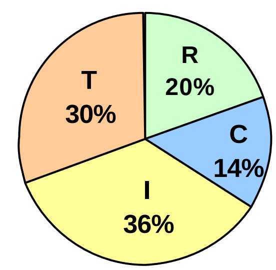
New CHP Capacity (2005-2010):
0.9 MW (#39)

Average Capacity per Site (2005-2010):
0.3 MW

Total Primary Energy Consumption (2008):
1,186 trillion Btu (#29)

Average Gas Price (2009):
$7.69 per MCF† (#43)

Average Electricity Price (2010):
8.66¢ per kWh (#29)



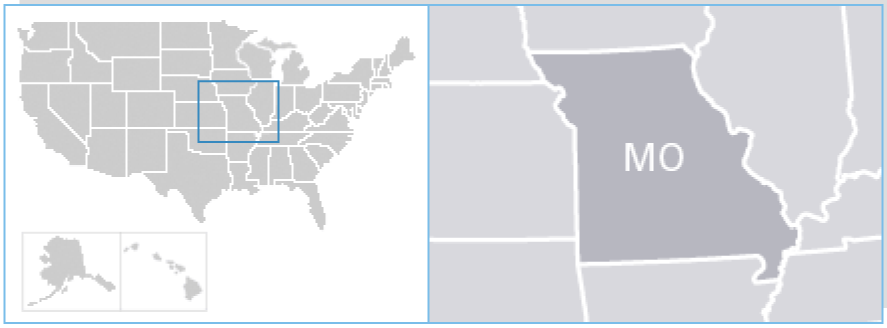
Mississippi, like most other states in the Southeast, has not historically presented a favorable market for CHP. The state earned only one point out of five in ACEEE's 2010 *Scorecard*. Three new CHP projects have been developed since 2005, though those three projects have only a combined capacity of 857 kW.

The biggest barrier to CHP deployment in Mississippi is basic economics. In some cases, developers report that "payback is negative," meaning that a CHP project may cost a facility more to fuel than just buying the electricity from the grid would otherwise cost. These economics have "hindered a number of different potential installations" from moving forward.

There is no renewable energy or energy efficiency portfolio standard in Mississippi, and there is little incentive for utilities to pursue CHP. Developers believe that such standards would "greatly benefit CHP" in the state. There is a state-administered low-interest loan program for energy investments that can be used for CHP projects. There are also some incentives available to some customers. Two performance incentives are available to CHP facilities that are fueled by biomass, but only for those projects located in TVA territory, in the northern part of the state. While the older program was viewed as not very attractive for most CHP projects due to size limitations, the newer program, a standard offer program for projects between 200 kW and 20 MW, could help future biomass-powered CHP systems become more economic in TVA territory.

Another significant barrier to greater CHP deployment in Mississippi is a lack of interconnection standards. Projects have reportedly faced seemingly endless fees and extensive paperwork requirements, frustrating developers and discouraging them from attempting to deploy projects in the state. Mississippi chose not to adopt new interconnection standards after considering such a move in response to the requirements of the federal Energy Policy Act of 2005. Absent an interconnection standard, the state's utilities may respond to interconnection requests as they wish. Entergy and Southern Company are reportedly actively hostile to CHP, while TVA tends to encourage CHP when it appears to be advantageous for a customer.

MISSOURI



New CHP Sites (2005-2010):
1 site (#43)

New CHP Capacity (2005-2010):
10.7 MW (#25)

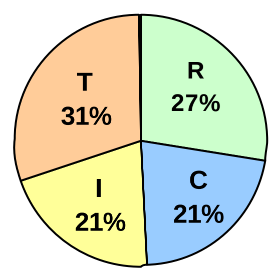
Average Capacity per Site (2005-2010):
10.7 MW

Total Primary Energy Consumption (2008):
1,937 trillion Btu (#20)

Average Gas Price (2009):
$11.03 per MCF (#23)

Average Electricity Price (2010):
7.95¢ per kWh (#35)

Energy Consumption by Sector



The CHP market in Missouri is not a favorable one. The state received two out of five points in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Missouri installed one new CHP system with a capacity of 10.7 MW.

Missouri's electricity rates are slightly lower than average for the country, but the exceptionally low rates for commercial and industrial facilities make it much more difficult for CHP to look attractive. With typical payback periods of 10 to 15 years, large CHP projects rarely come to fruition.

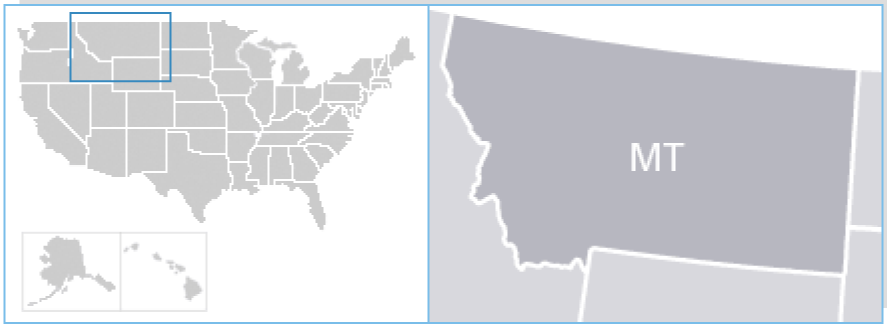
In addition to the inertia of the business community, the electric utility community makes CHP development in Missouri difficult. There are no financial incentives available for CHP projects in the state, and the disincentive associated with lost revenue from DG discourages utilities from pursuing it. Stakeholders in Missouri point to utilities as a major barrier to development, as a lack of a reasonable interconnection standard and lack of restrictions on standby rates give utilities free rein to make CHP installations and operation particularly difficult. Indeed, interconnection into the grid was cited as one of the biggest challenges to CHP deployment.

What little CHP there is in Missouri was primarily implemented in the industrial sector over 20 years ago thanks to negotiated preferential utility rates. For smaller applications—such as institutions or hospitals—CHP "just doesn't stand a chance," according to one Missouri CHP supporter Dealing with utilities in the state is very difficult, and because of a largely vertically-integrated electric utility structure, developers cannot simply take their business elsewhere.

Some utilities are more amenable to CHP than others, but IOUs in particular have been unfriendly toward CHP. Industrial energy consumers and utilities in Missouri have a contentious history and have historically not trusted each other, making any negotiations difficult. Some municipal utilities and cooperatives are more interested in CHP, but typically only on a small scale, and the economics of small projects are rarely attractive in the state.

Uncertainty also plays a role in stymieing further development. Senate Bill 376, which establishes funding and programs for cost-effective energy efficiency, will determine quite a bit about the future of energy use in Missouri. Many industries are putting efficiency projects on hold, awaiting a greater degree of certainty with regard to their investments. Once the rulemaking is complete and complementary studies have been released, Missouri may see an upsurge in energy efficiency expenditures, including for CHP. A recent (2011) order opened a docket with the Public Service Commission to consider interconnection and net metering standards.

MONTANA



New CHP Sites (2005-2010):
4 sites (#19)

New CHP Capacity (2005-2010):
17.6 MW (#17)

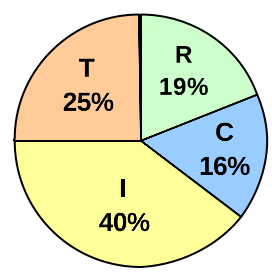
Average Capacity per Site (2005-2010):
3.3 MW

Total Primary Energy Consumption (2008):
434 trillion Btu (#44)

Average Gas Price (2009):
$9.32 per MCF (#33)

Average Electricity Price (2010):
7.77¢ per kWh (#37)

Energy Consumption by Sector



Montana has historically had a fairy unfavorable CHP market. It scored one point out of a possible five in ACEEE's 2010 *Scorecard*, and has seen four new CHP systems installed between 2005 and 2010. However, CHP appears to have recently attracted newfound attention from certain stakeholders.

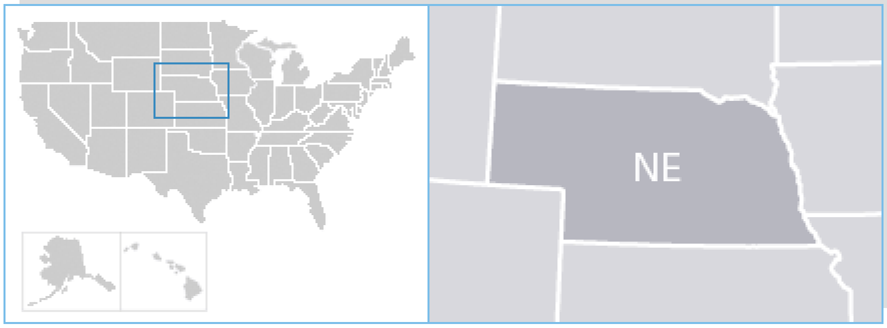
Montana, like much of the Northwest, has a large wood products industry that yields substantial biomass in its manufacturing processes. "Biomass is the story" of CHP in Montana. In addition to the wood products industry, the state has over 5 million acres of pine beetle-kill wood. Throughout the West, this wood has been helping to make the case for biomass-fueled CHP.

The state's RPS, which has set a 15% by 2015 goal, counts biomass-fueled CHP toward its goal. To date, the state's largest investor-owned utility, NorthWestern Energy, has met over half of its RPS goals with wind power alone (EQC 2010). Biomass supporters are working to ensure that the utility is encouraged to diversify its future RPS projects, and it appears that the utility itself has recently identified biomass as an important resource.

In 2009, the state legislature adopted House Joint Resolution 1, which requested a study on the feasibility of using biomass to meet Montana's future energy needs. In response, various state agencies have identified biomass-fueled CHP as an important energy opportunity and gathered interested stakeholders to help develop a biomass plan for the state and address barriers to its implementation. The state helped fund several biomass-focused feasibility studies, including one for NorthWestern Energy. The utility studied the applicability of biomass-fueled CHP at the state's sawmills and is currently developing a coalition of interested stakeholders to identify and address the barriers. The biggest barriers appear to be economics (the avoided cost amount paid for biomass-fueled CHP is widely viewed as too low) and fuel transportation challenges (moving heavy biomass from its source to the point of incineration) can be challenging and expensive, and securing long-term contracts for biomass can be difficult.

Montana also suffers from constraints along its transmission lines—an issue that CHP could help alleviate. During winter, when heating loads are high, the lines are often full. Supporters have identified these constraints as another reason to support expanded investment in biomass CHP. The state legislature and regulator have indicated that removing barriers to biomass CHP is important to the state's economic future, but developers and supporters alike remain unsure that their needs will be addressed by the next legislative session or current regulatory commission.

NEBRASKA



New CHP Sites (2005-2010):
2 sites (#34)

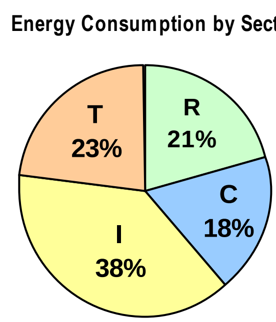
New CHP Capacity (2005-2010):
72.0 MW (#10)

Average Capacity per Site (2005-2010):
36 MW

Total Primary Energy Consumption (2008):
782 trillion Btu (#36)

Average Gas Price (2009):
$7.65 per MCF** (#44)

Average Electricity Price (2010):
7.60¢ per kWh (#41)



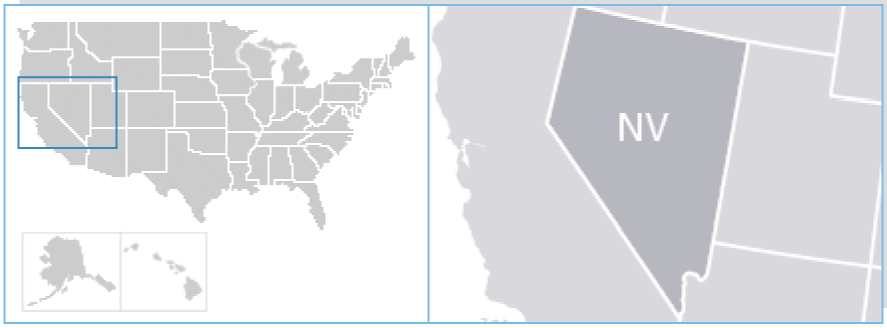
The CHP market in Nebraska is very unfavorable. Nebraska received the lowest score in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Nebraska installed two new CHP systems with a combined capacity of 72 MW. 97% of that capacity is a 70 MW system owned and operated by Archer Daniels Midland at a large corn milling facility. This system is coal-fired and was conceived primarily as a convenient fuel sourcing opportunity.

The only state in the U.S. where all electric utilities are publicly-owned, Nebraska boasts some of the cheapest electricity prices in the country. Such low rates make it difficult for businesses to justify investing upfront capital in CHP systems, as payback periods are generally extensive.

All electric utilities are owned by their customers and have been supportive of working with ratepayers to install CHP. Utilities typically do not resist interconnection or other installation procedures. However, with a notable lack of any state financial incentives, and no incentives being offered by the not-for-profit electric utilities, the sheer economics of CHP are nearly impossible to surmount.

Financing was also mentioned as a barrier to capital investment. The economic recession that began in 2008 has made it much more difficult to find adequate capital to finance a project and Nebraska's unfavorable spark spread makes CHP ventures there even less attractive to investors.

NEVADA



New CHP Sites (2005-2010):
2 sites (#34)

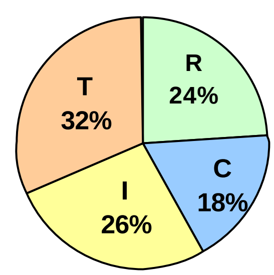
New CHP Capacity (2005-2010):
9.2 MW (#27)

Average Capacity per Site (2005-2010):
4.6 MW

Total Primary Energy Consumption (2008):
750 trillion Btu (#37)

Average Gas Price (2009):
$11.79 per MCF (#18)

Average Electricity Price (2010):
10.04¢ per kWh (#18)



The CHP market in Nevada is not very favorable. The state received a score of two out of five in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Nevada installed one new CHP system with a capacity of 0.03 MW.

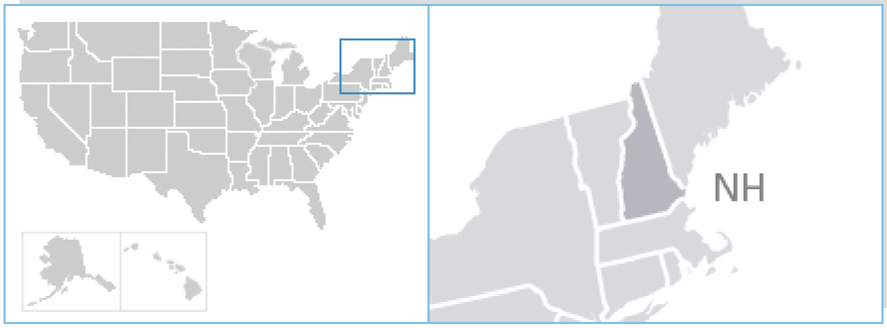
Nevada's electricity rates are about average for the country. Stakeholders in Nevada cite the spark spread as a challenge to CHP development, but with relatively low natural gas prices, it is the abundance of cheap coal that really serves to push economic analyses against CHP's favor. The state offers no financial incentives to encourage CHP development.

An interconnection standard passed in Nevada in 2003 applies only to CHP systems fueled by biogas, biomass, LFG, municipal solid waste, and tire-derived fuel. However, every CHP system that has been installed in the state is fueled by natural gas, so the standard has not helped make the process of interconnection any easier. This provides utilities with the opportunity to draw out the process for interconnection by dragging their feet and requiring a number of sometimes superfluous studies.

Nevada's Energy Portfolio Standard (EPS) was established in 1997 and expanded to include energy savings from efficiency measures in 2005. It requires the state's two IOUs, Nevada Power and Sierra Pacific Power, to derive or save a minimum percentage of the electricity they sell from renewable energy resources or energy efficiency measures. CHP systems are eligible under the EPS as a "qualified energy recovery process," but only "the heat from exhaust stacks or pipes used for engines or manufacturing or industrial processes" used to generate electricity is considered to be an eligible CHP process. However, these measures have not proved to be a great enough incentive to encourage further CHP development.

With a heavy reliance on the tourism industry and a bastion of energy consumption in the city of Las Vegas, electric reliability in Nevada is a huge issue. There are many opportunities in the hotel and casino industries for CHP, which could also provide critical backup power to the grid. However, with economic barriers that are difficult to overcome and a lack of strong state polices, few opportunities for CHP have been capitalized.

New Hampshire



New CHP Sites (2005-2010):
4 sites (#19)

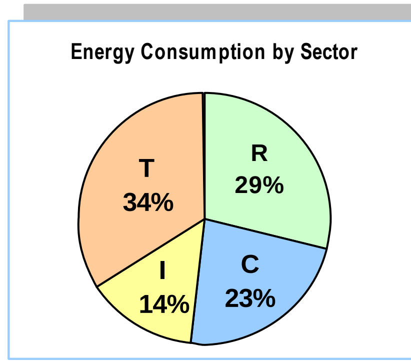
New CHP Capacity (2005-2010):
0.8 MW (#40)

Average Capacity per Site (2005-2010):
0.2 MW

Total Primary Energy Consumption (2008):
311 trillion Btu (#46)

Average Gas Price (2009):
Data not available

Average Electricity Price (2010):
14.75¢ per kWh (#6)



The CHP market in New Hampshire is generally unfavorable. The state received two out of five points in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, New Hampshire installed 4 new CHP systems with a combined capacity of 0.8 MW.

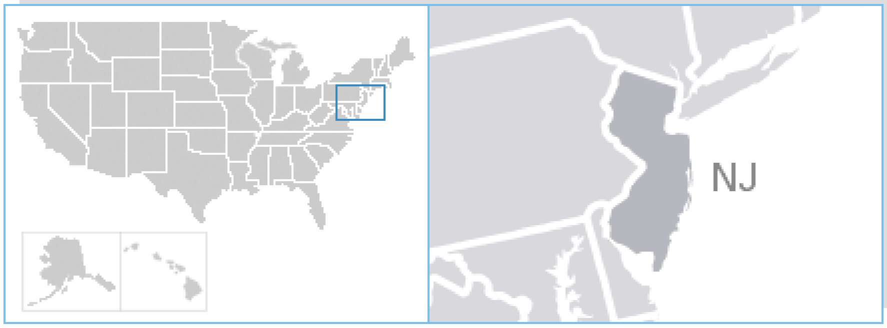
According to New Hampshire CHP supporters, there are three main components to state barriers to CHP. The first is a general lack of education of the benefits of CHP among industry, potential clients, and legislators and regulators. The second is the lack of available financing for CHP projects. The third is a lack of a unified coalition or other entity that works as a voice for CHP within New Hampshire. Largely because of these factors, New Hampshire has seen a dearth of new installations.

Electricity rates in New Hampshire are some of the highest in the country, making CHP projects relatively economical. Spark spread does not impede development as it does in other states; in fact, New Hampshire is one of the few states with high electricity rates that have not seen much CHP deployment. With a consistently high thermal demand throughout the state, New Hampshire is ripe for a slew of new CHP projects, so it is mainly non-economic barriers that are playing a key role in stymieing development.

Utilities in New Hampshire have not proven to be a significant barrier to CHP projects. Unitil, which is both an electric and gas utility, has been actively pursuing opportunities for CHP. There is some concern that as interest in CHP increases, resistance by electric utilities may increase as well, but these challenges can be overcome by including utilities in the process from the start and establishing mutually beneficial arrangements between hosts and developers.

With a multitude of opportunities for new systems, energy prices that would tend to favor CHP, and a lack of resistance from utilities, the barriers that remain are educational and organizational. According to stakeholders, the New Hampshire Public Utilities Commission is largely unaware of the benefits of CHP, as are potential hosts. There is no state combined heat and power initiative as there is in other states, and no other active coalition that supporters for sound CHP policies and regulations. With an injection of outreach, advocacy, technical assistance, and education, CHP has the opportunity to make significant headway in New Hampshire.

NEW JERSEY



New CHP Sites (2005-2010):
18 sites (#7)

New CHP Capacity (2005-2010):
14.1 MW (#22)

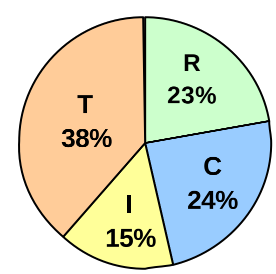
Average Capacity per Site (2005-2010):
0.8 MW

Total Primary Energy Consumption (2008):
2,637 trillion Btu (#13)

Average Gas Price (2009):
$11.31 per MCF (#20)

Average Electricity Price (2010):
14.88¢ per kWh (#4)

Energy Consumption by Sector



The CHP market in New Jersey is a relatively favorable one. The state received a score of four out of five in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, New Jersey installed 18 new CHP systems with a combined capacity of 14.1 MW.

With some of the most expensive electricity in the country, New Jersey's spark spread makes CHP a generally sound investment from an economic standpoint. Because of this, there is a fair amount of activity among developers, especially in the institutional sector, but obstacles remain.

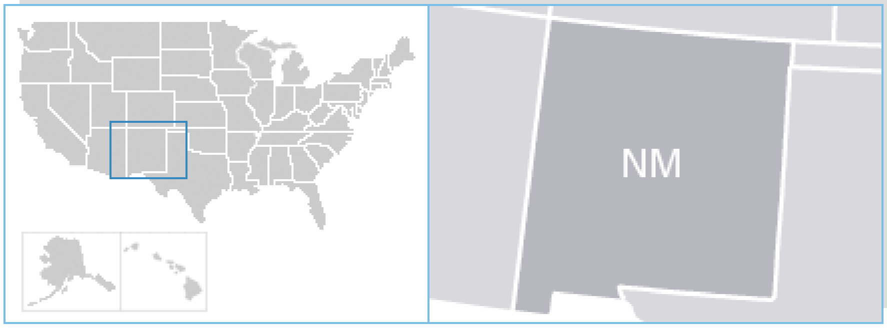
Barriers to greater CHP deployment in New Jersey including finding sufficient financing and the auxiliary costs sometimes required for projects. For example, any facility that installs a CHP system for the first time must have on staff a licensed operating engineer, and a system running 24 hours a day needs an operator on staff at all times.

While gas utilities in New Jersey are very supportive of CHP, electric utilities do not have strong incentives to help customers pursue CHP. With interconnection regulations that leave the process largely to the discretion of utilities, the process can be protracted and costly. Additionally, state regulations have not yet addressed utility standby rates to rein in unreasonable fees. Stakeholders in New Jersey point to decoupling as a potential starting point for eliminating electric utilities' aversion to distributed generation.

However, a new rule adopted in New Jersey in 2010 has helped some CHP systems find a good market for their excess power. It allows an entity to sell electricity to any facility to which it is also selling thermal energy services. Importantly, this rule also explicitly requires that such CHP systems be allowed to use existing electrical infrastructure to transport the power, and that such sales can occur across public right-of ways. The local utility may only charge a standard transportation tariff to provide the transportation service (New Jersey 2009). CHP developers around the country have referenced this rule as one to be emulated and copied.

Though the state has made some great progress, recent budget raids of energy efficiency funds in New Jersey have left CHP programs under-funded. ARRA funds have benefited the state, though, and $18 million worth of grants will likely move a number of projects forward that would have otherwise stalled. In 2010, New Jersey eliminated a sales and use tax on natural gas used in CHP facilities. This may encourage more CHP development.

NEW MEXICO



New CHP Sites (2005-2010):
0 sites (#45)

New CHP Capacity (2005-2010):
0 MW (#45)

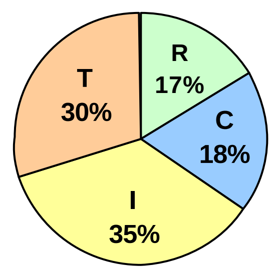
Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
693 trillion Btu (#38)

Average Gas Price (2009):
$7.18 per MCF (#49)

Average Electricity Price (2010):
8.60¢ per kWh (#30)

Energy Consumption by Sector



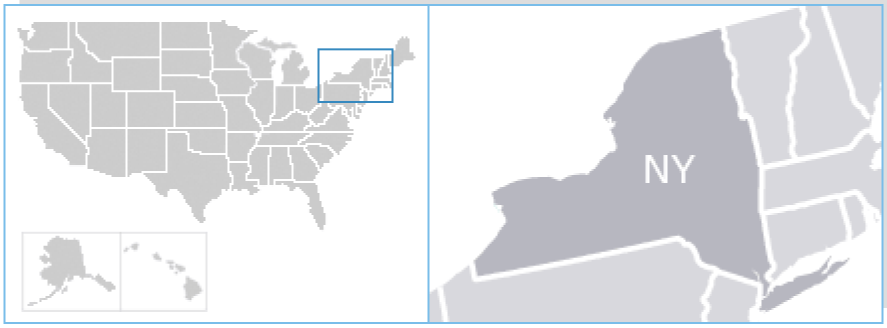
The market for CHP in New Mexico is somewhat unfavorable. However, the state did score four points out of a possible five in ACEEE's *Scorecard*, reflecting a number of good in-place policies designed to support new CHP. New Mexico did not see any new CHP installations between 2005 and 2010.

The main reasons CHP has not had greater deployment in New Mexico are economics, the state's demographics, and customer education. Though New Mexico's abundant natural gas resources could make gas-powered CHP projects attractive for certain sectors, it appears that few facilities are currently interested in pursuing CHP projects. Few concentrations of industrial uses are found in New Mexico as well. The state is sparsely populated, and the majority of economic activity and majority of land are dedicated to government activities. So the particular applications in which CHP makes sense are limited by the few types of land uses that lend themselves to CHP.

CHP is "not actively promoted" within the state and suffers from "low visibility." The state's utilities do not actively promote CHP as an energy efficiency resource, and there are no incentives for utilities to do so. New Mexico's RPS, passed in 2007, does not count waste energy as a renewable resource, although supporters attempted to add it as an eligible resource. Some industrial firms can take advantage, however, of a 6% tax credit for waste heat recovery projects on existing equipment.

There is relatively no new CHP activity in the state at present. Older in-place projects have been in the institutional sector primarily, including several campuses and municipal wastewater and landfill operations. One 17 year-old project using biogas from wastewater digesters is currently being re-bid to be rebuilt because the old system is aging and deteriorating.

NEW YORK



New CHP Sites (2005-2010):
101 sites (#2)

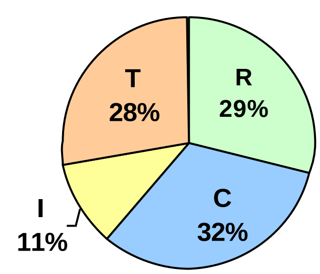
New CHP Capacity (2005-2010):
102.8 MW (#5)

Average Capacity per Site (2005-2010):
1 MW

Total Primary Energy Consumption (2008):
3,988 trillion Btu (#5)

Average Gas Price (2009):
$12.27 per MCF (#12)

Average Electricity Price (2010):
16.46¢ per kWh (#3)



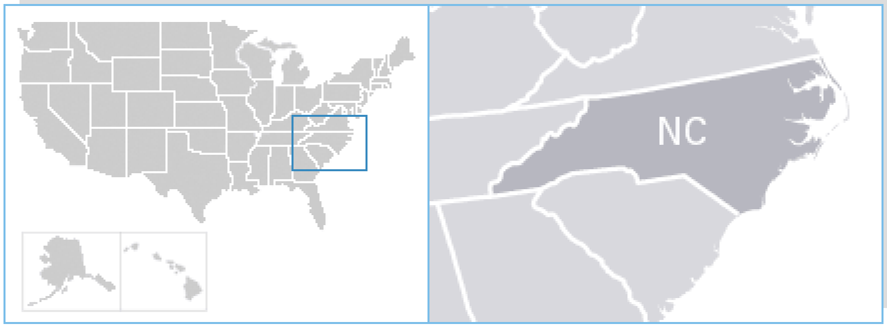
The CHP market in New York is quite favorable, and is routinely cited by CHP developers as “the best in the country.” The state earned all five possible points in ACEEE’s 2010 *Scorecard*. Additionally, the CHP program at the New York State Energy Research and Development Authority (NYSERDA) was recognized by ACEEE in 2010 as one of the country’s best energy efficiency programs. Between 2005 and 2010, New York saw 101 CHP projects installed, for a total combined capacity of 102.8 MW.

New York’s constrained electric grid and high electricity prices have made CHP attractive for years, and it was one of the first states to establish a PBF to support energy efficiency. NYSERDA’s robust CHP programs include production incentives, technical assistance, technology transfer efforts, and demonstration projects. These programs have been instrumental to the continued health of the state’s CHP market, identifying market inefficiencies revealed by in-place demonstration programs and targeting policy changes to remove them. However, some CHP projects in the state do not use NYSERDA’s programs, especially in the public sector. These projects are generally well-funded by public funds and do not need the incentives NYSERDA offers. In some cases, since the rigor of NYSERDA’s processes has not been brought to bear, this has yielded poorly sized projects that do not maximize system efficiency.

Due to market needs and improved regulation, New York’s utilities have begun to embrace CHP and interconnection and standby rate issues appear to have eased. Utilities tend to allow for larger projects than the in-place state interconnection standard. National Grid, the state’s largest natural gas utility, strongly supports CHP, and the state’s gas utilities offer discounted rates to CHP projects. These discounts help, but do not by themselves move projects forward. CHP does not count as an eligible resource for the state’s EERS, because it is not considered a “lowest-cost resource,” though utilities are encouraged to promote CHP. However, some CHP is eligible for the state’s RPS, and the state’s PBF program funds the substantial CHP activity at NYSERDA.

The biggest barriers to CHP in the state can be found in New York City, where real estate prices and Con Edison’s old networked grid present financial and technical difficulties. The grid is being overhauled to allow for synchronous interconnection, but progress has been too slow for some. Permitting from city agencies is a big enough barrier that some CHP systems are deployed as “bootleg” projects—they are not reported to the proper authorities and do not get necessary permits. In response, city agencies are developing a guide for developing CHP projects in the city.

NORTH CAROLINA



New CHP Sites (2005-2010):
13 sites (#8)

New CHP Capacity (2005-2010):
17.6 MW (#18)

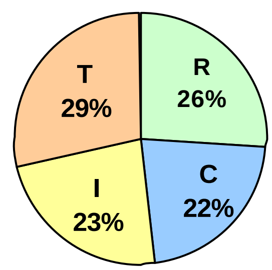
Average Capacity per Site (2005-2010):
1.4 MW

Total Primary Energy Consumption (2008):
2,702 trillion Btu (#12)

Average Gas Price (2009):
$11.30 per MCF (#21)

Average Electricity Price (2010):
8.78¢ per kWh (#27)

Energy Consumption by Sector

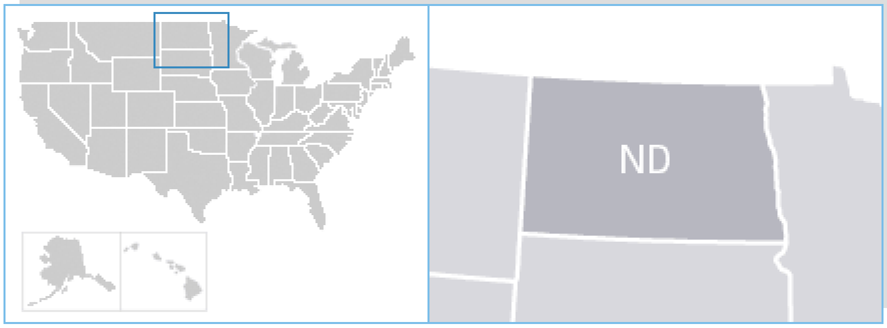


The CHP market in North Carolina is currently increasingly favorable, especially compared to other Southeastern states. The state received the full possible five points in ACEEE's 2010 *Scorecard*. However, substantial barriers remain. Between 2005 and 2010, 13 projects were installed, representing 17.6 MW of capacity.

Gas utilities, particularly Piedmont Natural Gas, continue to be very supportive of CHP projects in the state. But the biggest barriers to greater deployment in North Carolina are low cost electricity and continuing resistance to DG from the state's electric utilities. Duke appears to be warming to CHP, albeit in a model where it would own and be able to recover the cost of the CHP assets. Cheap electricity and low heat loads in portions of the state's manufacturing sector can make many projects financially challenging to justify, but projects that could be economic sometimes become uneconomic when electric utilities offer lower, so-called "economic development" rates to discourage CHP. Both Progress and Duke have engaged in this. They've also imposed burdensome standby rates. Electric utilities in the state are not properly incentivized to deploy CHP. Though CHP is explicitly allowed as an eligible resource in the state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), it has not yet made much of an impact on project economics thus far. The first year in which utilities will be held accountable for meeting REPS goals is 2012, and developers expect to see additional impact from the REPS, especially if it is amended to allow thermal energy credits.

North Carolina leads the Southeast in CHP policies and has recently formed a CHP Initiative with participation from utilities, industry, and supporters. Supporters hope success in North Carolina will lead to success throughout the region. Project implementation can still be described as challenging, but the environment for CHP appears to be improving. A new 35% energy tax credit has garnered substantial interest from CHP manufacturers and developers, though no new installations appear to have resulted from the credit. Supporters, developers, and equipment manufacturers speak of a palpable "momentum" in the CHP market in the state due to a "good combination" of interested parties. They also note that the state's performance contracting process for addressing energy needs in government facilities is too onerous to facilitate much CHP development. Also, among non-regulated utilities, interconnection remains difficult and not streamlined. Though North Carolina has made some great strides, it is clear that to capitalize on the state's expanded CHP tax credit, state policymakers must directly address some of the remaining barriers to greater CHP deployment.

NORTH DAKOTA



New CHP Sites (2005-2010):
4 sites (#19)

New CHP Capacity (2005-2010):
23.0 MW (#15)

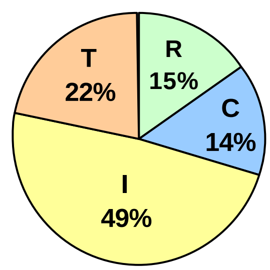
Average Capacity per Site (2005-2010):
5.8 MW

Total Primary Energy Consumption (2008):
441 trillion Btu (#43)

Average Gas Price (2009):
$7.02 per MCF (#50)

Average Electricity Price (2010):
7.02¢ per kWh (#47)

Energy Consumption by Sector



The CHP market in North Dakota is unfavorable. The state scored one point out of a possible five in ACEEE's *Scorecard*, and installed four CHP projects between 2005 and 2010, representing 23 MW of installed capacity.

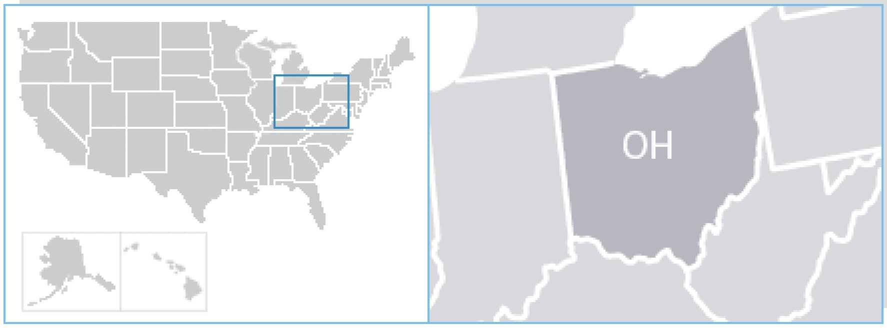
The biggest barrier to greater CHP deployment in North Dakota is economics. North Dakota has very cheap energy and substantial coal reserves that allow it to produce most of its electricity from in-state coal at very low prices. There is "very little interest in on-site generation" in the state due to the lack of a business case for such generation.

Utilities in the state do not have an incentive to explore distributed generation opportunities. A state renewable and recycled energy objective is to have 10% of all retail electricity sold in the state generated from renewable or recycled energy sources by 2015. Utilities are not legally bound to meet this objective, and new CHP does not count as an eligible resource. Only waste energy recycled from existing facilities can count towards the objective. This policy has done little to excite developers about deploying distributed generation of any type in North Dakota.

The economics of CHP projects in North Dakota state are also hurt by the standby rates used by the state's utilities to charge for backup and standby service. The rates are particular onerous at Xcel Energy, where a type of 11-month ratchet is used to determine the billing demand charge.

Coal, recycled energy, and biomass appear to be the available opportunities for CHP developers in North Dakota. Current projects take advantage of the waste heat opportunities in industry and ethanol production, and on natural gas pipeline compressors. However, until the economics improve greatly, little new CHP activity is expected in the state.

OHIO



New CHP Sites (2005-2010):
8 sites (#14)

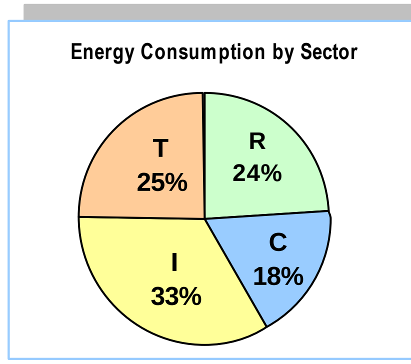
New CHP Capacity (2005-2010):
94.6 MW (#7)

Average Capacity per Site (2005-2010):
11.8 MW

Total Primary Energy Consumption (2008):
3,987 trillion Btu (#6)

Average Gas Price (2009):
$10.26 per MCF† (#28)

Average Electricity Price (2010):
9.15¢ per kWh (#24)



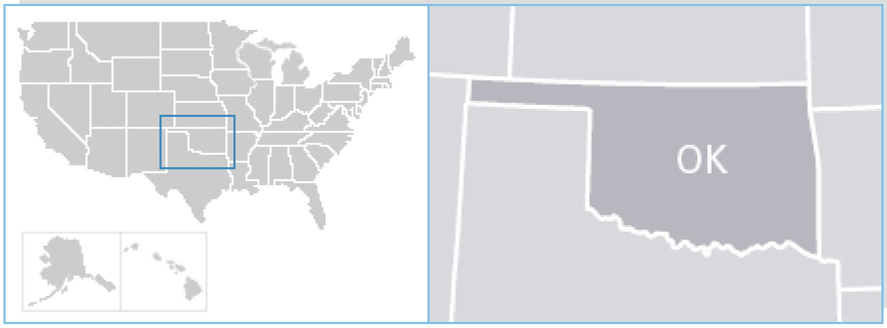
The CHP market in Ohio is "good on paper," but in practice, developers find it to be a fairly unfavorable market. Ohio earned all five points in ACEEE's 2010 *Scorecard* and has seen the installation of seven new CHP projects between 2005 and 2010, representing almost 50 MW of capacity.

The biggest barrier to greater CHP deployment in Ohio is economics, though the economics appear to be heavily impacted by standby tariffs and other utility practices. "Standby rates have always been an issue" in the state. Some older CHP systems even installed backup diesel generators just to avoid paying the standby rates their local utility would charge. Though this practice does not appear to be as commonplace now, developers still remember when such practices were necessary. A multitude of riders keeps the tariff situation complicated. One developer says he "won't waste time" in Ohio, because of all of the barriers. It does not make business sense for him to try to find customers in the state, since projects take too long to see through to completion.

Excess paperwork and "red tape" were cited generally as barriers in Ohio. These were often in association with interconnection, despite Ohio's recent (2007) adoption of a new satisfactory interconnection standard. The actual implementation of the standard is not adequate for developers, who find that all of the state's major utilities make the deployment of new CHP projects difficult. These utilities do not appear to be adhering to the requirement that they make interconnection "not unduly burdensome or expensive for any applicant."

Although Ohio's large industrial base presents one of the largest potential markets for CHP in the Midwest, presently only 2.3% of the state's electrical generating capacity comes from CHP, well below the national average of 8.4%. The lack of support for CHP by the state's utilities is likely due in part to a lack of incentive for them to support distributed generation. Senate Bill 221, enacted in 2008, established an Alternative Energy Portfolio Standard, which explicitly includes CHP as an eligible resource. However, CHP is included within a tier of resources that utilities are not required to use. This standard, as well as some efforts at decoupling revenues from amount of electricity sales, are nascent, and thus have not had much chance to impact the Ohio market. "The whole industry is learning how to implement S.B. 221," so some developers remain hopeful that Ohio will soon be a more attractive market as the state's new policies will create economic incentive for utilities to deploy CHP in their service areas. Finally, a new bill passed in 2010 reduces the state tax burden on renewable and "advanced" sources of energy, including CHP that exports power to the grid. However, its impact may be minimal, as it only applies to systems that begin construction between 2009 and 2011.

OKLAHOMA



New CHP Sites (2005-2010):
0 sites (#45)

New CHP Capacity (2005-2010):
0 MW (#45)

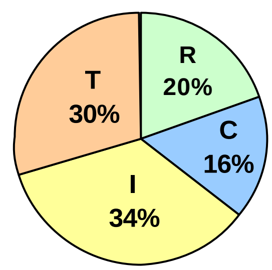
Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
1,603 trillion Btu (#23)

Average Gas Price (2009):
$12.09 per MCF (#15)

Average Electricity Price (2010):
7.59¢ per kWh (#42)

Energy Consumption by Sector



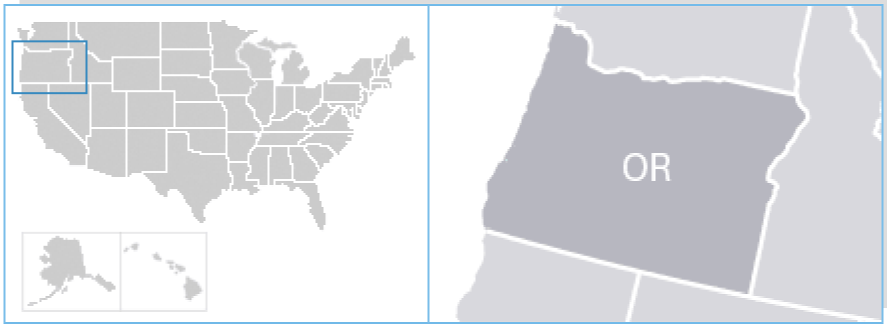
The market for CHP in Oklahoma is not favorable. The state received zero points out of a possible five in the CHP chapter of ACEEE's 2010 *Scorecard*, and has installed no new CHP projects between 2005 and 2010. However, a new 15 MW CHP project at the University of Oklahoma is currently in development, and the university has committed to fully funding the $70 million project with internal funds. Additionally, a new CHP project is being actively considered at the Oklahoma State University.

Oklahoma has not traditionally dedicated public funds to energy efficiency or renewable energy programs, and only in 2010 did the state set a renewable energy goal (not a mandate) that 15% of the total installed electric capacity in Oklahoma be derived from renewable resources by 2015. Energy efficiency resources, including waste heat, may count toward 25% of the 15% goal, but the renewable energy goal is largely seen as a way to primarily encourage more wind energy.

There is no interconnection standard for CHP, nor are there any dedicated incentives or other sources of funding. Few developers could identify any barriers because so few projects have been considered in the state. Oklahoma has fairly low electricity prices, so little economic incentive has existed to pursue CHP. The two biggest utilities in the state, Oklahoma Gas and Electric (OGE) and the Public Service Company of Oklahoma (PSO), do not have any programs in place to encourage CHP.

However, Oklahoma produces an abundance of natural gas, and OGE sells gas as well as electricity. CHP could be a business opportunity for OGE, since many CHP systems are powered by natural gas. Developers have lately been pitching CHP systems to OGE as opportunities to build gas load, which has been viewed favorably by some within the company. It remains to be seen if the opportunity for increased gas load will be enough to move OGE and other gas utilities to work to encourage greater deployment of CHP.

OREGON



New CHP Sites (2005-2010):
10 sites (#9)

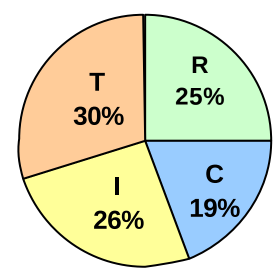
New CHP Capacity (2005-2010):
38.8 MW (#14)

Average Capacity per Site (2005-2010):
3.9 MW

Total Primary Energy Consumption (2008):
1,105 trillion Btu (#32)

Average Gas Price (2009):
$12.91 per MCF* (#8)

Average Electricity Price (2010):
7.55¢ per kWh (#43)



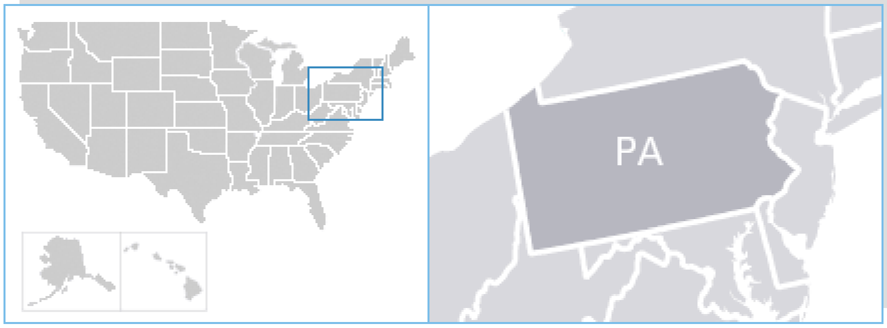
The CHP market in Oregon is relatively favorable. The state received four points out of a possible five in ACEEE's 2010 *Scorecard*, and has seen ten new CHP projects totaling 39 MW installed between 2005 and 2010. Most of this new capacity is powered by biomass, and a new biomass-powered project will soon add 26.8 MW to the state's overall capacity.

Economics are the main barrier to greater deployment in Oregon. "It's all about the spark spread," which tends to remain quite poor due to Oregon's cheap hydro- and coal-powered electric rates. As noted earlier in this report, one CHP advocate in the state asks of a prospective CHP developer, "If you were given this system for free, would it be economic to run it?" Given cheap power prices and low avoided cost rates (for PURPA projects), many developers say, "No." However, an electric rate hike is expected in the near future, which may tip the scales on some potential CHP projects.

Oregon offers a variety of incentives and financing options, and some CHP projects have found these programs to be very important. Incentives were critical for an 80 MW project at Oregon State University, though incentives do not, by themselves, move forward projects that would not have otherwise been deployed. One of the challenges to an expanded suite of services and incentives for CHP is that CHP is viewed as an electricity-saving measure by the PBF administrator, the Energy Trust of Oregon. CHP projects often do not meet the Trust's cost-effectiveness test, as the payback period is too long. CHP competes with other energy efficiency projects for the Trust's resources, and typically loses out to other efficiency measures that are more cost-effective in the near term. Some in the state suggest CHP should be treated as a gas efficiency measure, as some of the largest energy users in the state have substantial thermal loads. But few CHP support services target these customers, since most of their energy use is in the form of natural gas.

Electric utilities in Oregon have not been hostile to CHP, but they have no real incentive to help customers invest in it. Portland General Electric (PGE) is viewed as generally supportive of CHP, but CHP projects do not get any credit in the state's RPS. This is detrimental to the CHP market in Oregon and discourages utilities from encouraging CHP projects. Some utilities, particularly Pacific Power, seem interested in developing power purchase agreements with large-scale CHP projects. This interest appears to be growing among other utilities as well, in light of the fact that the PGE-owned Boardman coal plant, which provides about 5% of the state's power, will close in 2020. "There is momentum" in Oregon because, despite tough economics in some cases, "the culture is right" for CHP.

PENNSYLVANIA



New CHP Sites (2005-2010):
25 sites (#5)

New CHP Capacity (2005-2010):
80.9 MW (#9)

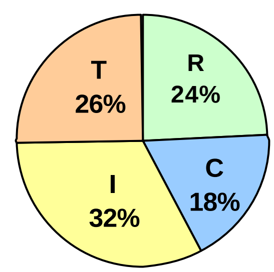
Average Capacity per Site (2005-2010):
3.2 MW

Total Primary Energy Consumption (2008):
3,900 trillion Btu (#7)

Average Gas Price (2009):
$12.10 per MCF (#14)

Average Electricity Price (2010):
10.42¢ per kWh (#16)

Energy Consumption by Sector



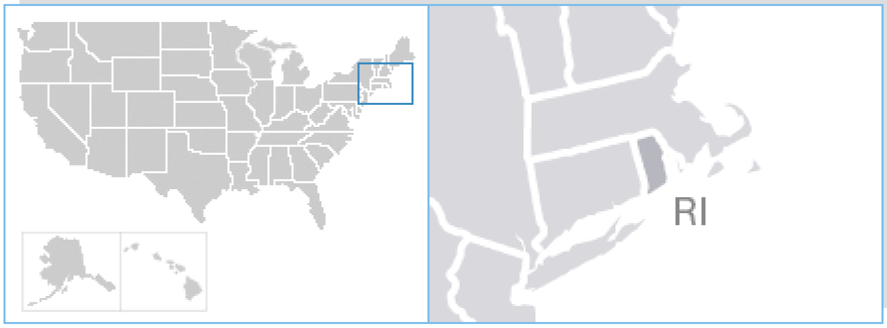
The CHP market in Pennsylvania is somewhat favorable. The state received all five possible points in ACEEE's *Scorecard*, reflecting a number of robust in-place policies and incentives that actively encourage CHP. 21 new CHP projects representing over 50 MW of installed capacity were installed in the state between 2005 and 2010.

Pennsylvania's Alternative Energy Portfolio Standard (AEPS) allows CHP to count as a resource, though it "doesn't help" projects, because the monetary value of satisfying the AEPS resource requirement is "pennies." However, 2008's Act 129 directed all large utilities in the state to develop energy efficiency plans and goals. These are widely viewed as critical to continued CHP deployment in the future. Most utilities submitted their plans in 2009 and are just beginning to deploy them. Some of these utilities realize "they can't just do light bulbs" and have engaged the state's CHP community to learn how they can best exploit the state's CHP potential. To be sure, no new CHP projects have yet been supported because of Act 129, but some in the CHP community expect to see the impact in the coming years.

Though only applicable to systems up to 5 MW, Pennsylvania's net metering laws are viewed as useful to smaller CHP systems. Some discussions among some stakeholders about raising the system size limit have occurred. Interconnection is not a big barrier, and utilities have largely adhered to the in-place interconnection standards and their attendant timelines. Though no utilities are viewed as "great" for their encouragement of CHP projects, good experiences with PECO were reported, and developers universally had good opinions of PJM Interconnection, the area's retail transmission organization.

A number of developers noted that Pennsylvania has continued to offer a favorable CHP market because of good regulations, rising electricity prices, and the new energy efficiency goals. An energy-intensive industrial sector is well suited to CHP. The Marcellus Shale, a previously untapped extensive natural gas field below much of the western and northern parts of the state, has the potential to yield substantial natural gas production in Pennsylvania for years. If the Marcellus find is as big as currently expected, it may offer future CHP developers a cheap and steady source of natural gas, reducing the risk often associated with natural gas-based CHP systems. Pennsylvania's more favorable economics, combined with active leadership on energy efficiency issues by the governor, have created an increasingly favorable environment for CHP. Developers view the state as a good target for future CHP projects, though up-front costs remain challenging for some of the larger projects.

RHODE ISLAND



New CHP Sites (2005-2010):
7 sites (#18)

New CHP Capacity (2005-2010):
1.6 MW (#38)

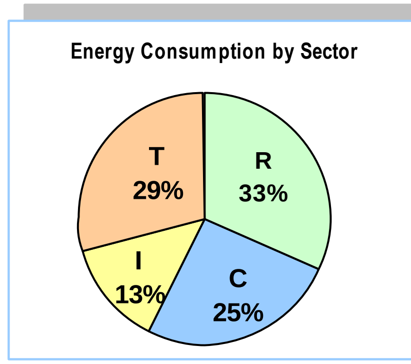
Average Capacity per Site (2005-2010):
0.2 MW

Total Primary Energy Consumption (2008):
220 trillion Btu (#49)

Average Gas Price (2009):
$14.93 per MCF (#4)

Average Electricity Price (2010):
14.20¢ per kWh (#8)

Energy Consumption by Sector



The CHP market in Rhode Island is currently relatively unfavorable. The state received two out of five points in the CHP chapter of ACEEE's 2010 *Scorecard*. However, Rhode Island is on an upward trend in state policies for CHP and seems poised to increase its CHP development significantly in the coming years. Between 2005 and 2010, Rhode Island installed seven new systems with a combined capacity of 1.6 MW.

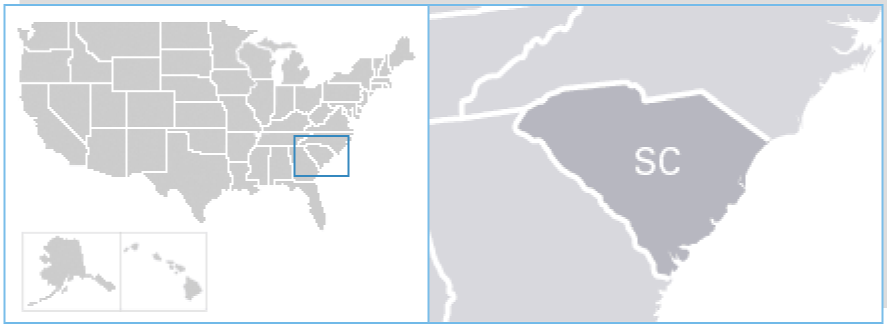
The initial capital investment needed for new projects has proven difficult for developers to attain. However, electricity prices in Rhode Island are among the highest of any state and natural gas prices have fallen to reasonable rates, so payback periods are not overly extensive as they are in many states.

In 2010, National Grid, an electric and gas utility that serves Rhode Island and other Northeastern states, launched an incentive program that applies to CHP systems, offering up to $750 per kW for new systems. While this rebate is certainly not a panacea, it will make the economics of CHP much more favorable in the state.

Rate structures in Rhode Island have historically added to the economic challenges for CHP. National Grid provides standby service on an entirely demand-based rate. Billing demand is typically based on the 15 minute maximum monthly demand or 75% of the maximum from the previous 11 months, whichever is higher. Interconnection has also been an issue for hosts, but National Grid is currently expediting the process of fixing both interconnection procedures and rate structures to better encourage CHP.

Other barriers to CHP in Rhode Island have included a lack of availability of natural gas, the cost of oil for oil-fired systems, a lack of education among customers, and a lack of vendors. Another issue has been the difficulty in finding suitable hosts; especially due to the small size of the state, is has been difficult for developers to find customers who have a need for both the heat source and the electricity together. Even once the price barriers and process barriers have been broken down, finding appropriate hosts will still be a challenge.

SOUTH CAROLINA



The CHP market in South Carolina is less than favorable. The state received one point out of a possible five in ACEEE's *Scorecard*, and has seen the installation of only three new CHP projects between 2005 and 2010. These projects represent 6 MW of installed capacity.

South Carolina has few policies designed to directly encourage CHP. The state's interconnection standard only applies to systems of 100 kW or less—far smaller than most CHP systems. Like North Carolina, South Carolina's utilities are not very supportive of CHP projects, due mostly to concerns about maintaining the electric demand from the state's industrial base. State utilities are in no way incentivized to pursue CHP, as the state did not adopt a proposed EERS introduced into the state legislature in 2009.

Developers and supporters say it is likely South Carolina will follow North Carolina's lead on energy policy, and that they expect to see South Carolina further embracing CHP in the coming years since North Carolina is heading in that direction. The general thought from developers was that South Carolina "learns from North Carolina's mistakes" and understands how to begin to develop new energy policies while avoiding contentious issues from having watched its northern neighbor fight similar battles years earlier.

South Carolina remains an unattractive market to most developers, who are simply unable to find an economic reason to pursue CHP projects in the state. Those economics and the generally unsympathetic attitude its utilities have toward CHP will keep developers from seriously considering South Carolina as a prime target for near-term CHP development.

New CHP Sites (2005-2010):
3 sites (#26)

New CHP Capacity (2005-2010):
6.0 MW (#29)

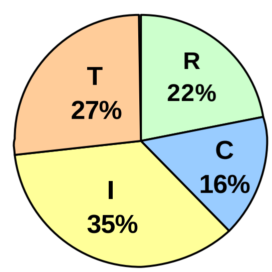
Average Capacity per Site (2005-2010):
2 MW

Total Primary Energy Consumption (2008):
1,660 trillion Btu (#22)

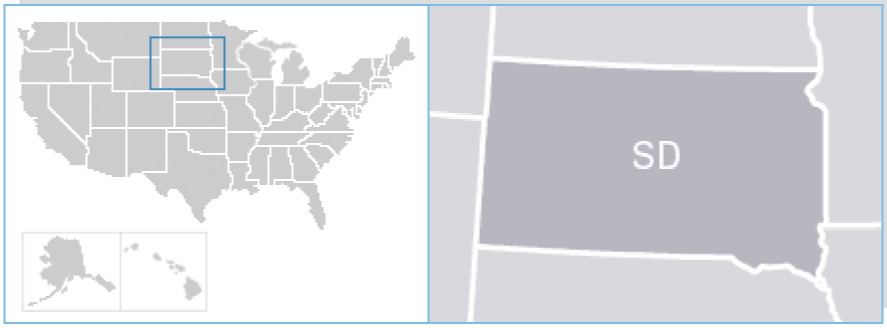
Average Gas Price (2009):
$10.65 per MCF** (#26)

Average Electricity Price (2010):
8.49¢ per kWh (#32)

Energy Consumption by Sector



SOUTH DAKOTA



New CHP Sites (2005-2010):
4 sites (#19)

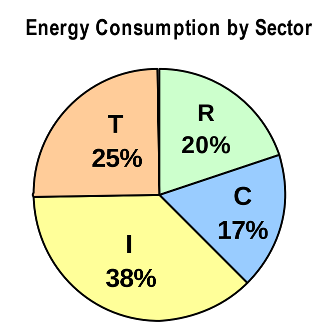
New CHP Capacity (2005-2010):
21.5 MW (#16)

Average Capacity per Site (2005-2010):
5.4 MW

Total Primary Energy Consumption (2008):
350 trillion Btu (#45)

Average Gas Price (2009):
$7.54 per MCF (#45)

Average Electricity Price (2010):
7.76¢ per kWh (#39)

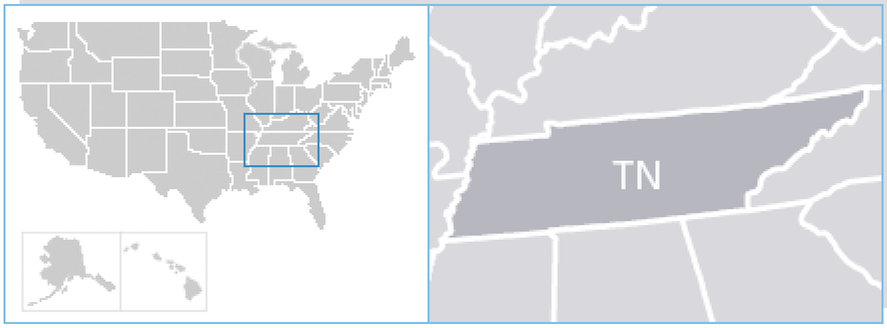


The CHP market in South Dakota is somewhat favorable. The state received three out of a possible five points in ACEEE's *Scorecard* and has seen the installation of three new CHP projects, totaling 16.5 MW of capacity, between 2005 and 2010.

The biggest CHP opportunity in South Dakota has been found in the compressor stations on the state's myriad natural gas pipelines. In these situations, the waste heat given off by the compressors is captured and drives turbines that create electricity for the local electric cooperative (Basin Electric Power Cooperative 2010, Hedman 2009). "It's just economics" to deploy CHP at these stations, and since the state already imports a lot of its electric generation, capturing whatever is generated in-state "just makes sense." More pipelines are in the works, and the likelihood of CHP at their compressor stations is high.

Utilities in South Dakota do not appear to actively work against new CHP installations, and some appear to be very interested in promoting CHP because it helps their customers lower their energy bills and is seen as a positive public relations activity. Utilities are encouraged to support distributed generation projects via a Renewable, Recycled and Conserved Energy Objective. The voluntary objective is considered to be a serious goal by most utilities, and the state's utilities appear to view CHP as a cost-effective way to diversify their portfolio now. The objective is viewed as a precursor to an in-place standard, so utilities have somewhat of an incentive to begin to build their renewable energy and energy efficiency portfolios now in preparation for a more binding standard.

Tennessee



New CHP Sites (2005-2010):
0 sites (#45)

New CHP Capacity (2005-2010):
0 MW (#45)

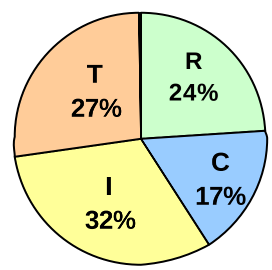
Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
2,261 trillion Btu (#15)

Average Gas Price (2009):
$9.58 per MCF (#30)

Average Electricity Price (2010):
8.54¢ per kWh (#31)

Energy Consumption by Sector



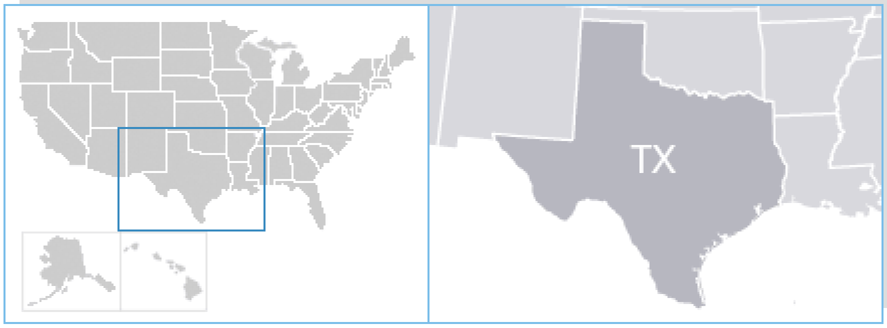
The CHP market in Tennessee is unfavorable. The state scored one point out of a possible five in ACEEE's *Scorecard*. Tennessee saw zero new CHP installations between 2005 and 2010, and only one installation since 2000.

Tennessee's energy markets are somewhat unique, because the Tennessee Valley Authority (TVA) is the generator of electricity for the nearly the entire state. TVA then distributes that electricity to public power distributors, municipal utilities, and cooperatives. As the largest publicly-owned utility in the country, TVA has the potential to influence a wide swath of the U.S. with its policies. TVA is a federal corporation, not subject to state regulators. TVA has not historically worked to support CHP deployment in its service area, but it is increasingly interested in helping its customers become more energy efficient. Supporters note recent "fruitful" conversations with TVA executives and staff about CHP, and also TVA's growing interest in finding new sources of energy, especially in conjunction with the development of TVA's new Integrated Resource Plan.

Beyond TVA, parts of Tennessee are served by distributors that buy their energy from TVA. These entities have not worked to bring CHP to their customers and, since they tend to "move as a block," there's little likelihood of one of them stepping into the CHP arena soon. They have not historically viewed energy efficiency and renewable energy deployment as part of their purview, and in fact might take an unfavorable view of a loss of industrial or large commercial load to new CHP.

Developers were unable to cite any barriers to CHP deployment in Tennessee beyond simple economics, since so few projects have been developed in the state in the past ten years. Tennesseans enjoy cheap power, thanks to TVA's reliance on coal and hydropower. Though no direct incentives for CHP exist, several loan programs in the state can be used to fund certain types of CHP projects. Many developers and supporters in the region are excited about the prospect of a TVA more focused on energy efficiency, and see Tennessee's large industrial load as well-suited for future CHP projects. As TVA works to develop its new long-term plan, these people remain involved in discussions and are working to ensure CHP is prioritized as a useful energy resource for Tennessee's future needs. One advocate noted he is "relatively optimistic" about the future of CHP in Tennessee.

TEXAS



New CHP Sites (2005-2010):
8 sites (#14)

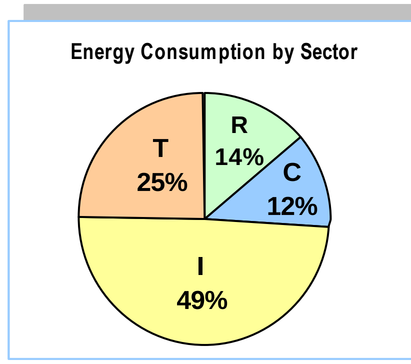
New CHP Capacity (2005-2010):
380.8 MW (#1)

Average Capacity per Site (2005-2010):
47.6 MW

Total Primary Energy Consumption (2008):
11,552 trillion Btu (#1)

Average Gas Price (2009):
$7.82 per MCF (#41)

Average Electricity Price (2010):
9.44¢ per kWh (#21)



The CHP market in Texas is relatively favorable compared to other states. The state received a maximum score for its CHP score in ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Texas installed 8 new CHP systems with a combined capacity of 380.8 MW.

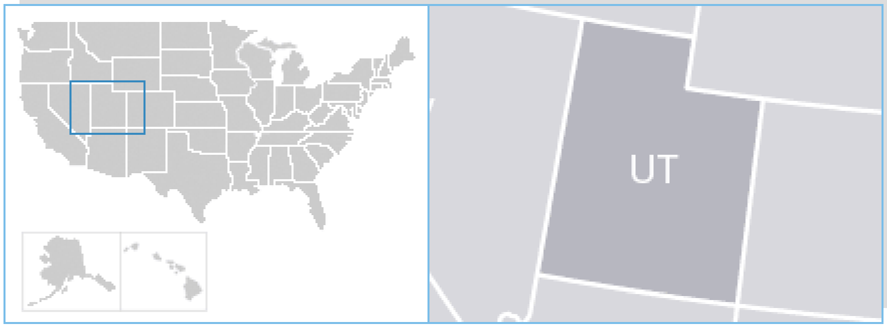
Texas lacks a uniform utility market structure. The area covered by the Electric Reliability Council of Texas (ERCOT) has been effectively deregulated for years. Some CHP systems have benefited from being able to sign long-term contracts for excess power under this market structure. Many commercial and industrial electricity sales occur through bilateral contracts where there is no specific rate structure in place, so it is hard for some potential CHP clients to forecast future electric rates for their analyses.

Within ERCOT territory there are many municipal utilities and electric cooperatives that opted out of deregulation and are still vertically integrated monopolies with an exclusive right to sell electricity in their territory. While these providers have not historically been a barrier to CHP, there is not much CHP being developed outside of deregulated areas, with the exception of some activity in San Antonio and Austin.

Despite relatively low electricity rates in Texas, economics are not as much of a barrier as other factors. However, they can still stymie a project, as most projects simply come down to dollars and sense. With a five- to six-year payback range being typical, many projects do not move forward. Many projects are currently below 20 MW in size, so under $25 to 30 million in cost. Unfortunately, these amounts prove too small to garner the interest of most hedge funds and financial institutions, which could provide some needed market liquidity. Developers and other stakeholders point out that loan guarantees or other financial incentives would help improve the capital constraints associated with CHP projects and encourage more deployment.

CHP does not count toward Texas's renewable generation requirement, and while the state's Energy Efficiency Improvement Program (EEIP)—the first energy efficiency resource standard in the country—now credits CHP systems of 10MW or less toward utility efficiency goals the program's impact on CHP has been minimal, since many of the facilities best-suited for CHP do not pay into and take advantage of the program. Still, utilities have acknowledged that they cannot ignore CHP as part of the energy efficiency puzzle and are determined to create an incentive that can be a statewide standard. And with an aging fleet of older CHP plants in place from several decades of PURPA activity, new opportunities for CHP will likely present themselves within the state's industrial sector as facilities look to replace the retiring plants.

UTAH



New CHP Sites (2005-2010):
2 sites (#34)

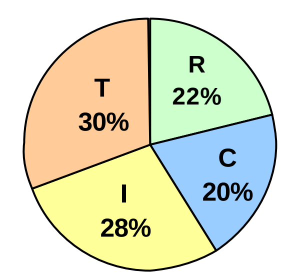
New CHP Capacity (2005-2010):
12.1 MW (#24)

Average Capacity per Site (2005-2010):
6.1 MW

Total Primary Energy Consumption (2008):
799 trillion Btu (#35)

Average Gas Price (2009):
$7.36 per MCF (#48)

Average Electricity Price (2010):
7.10¢ per kWh (#46)

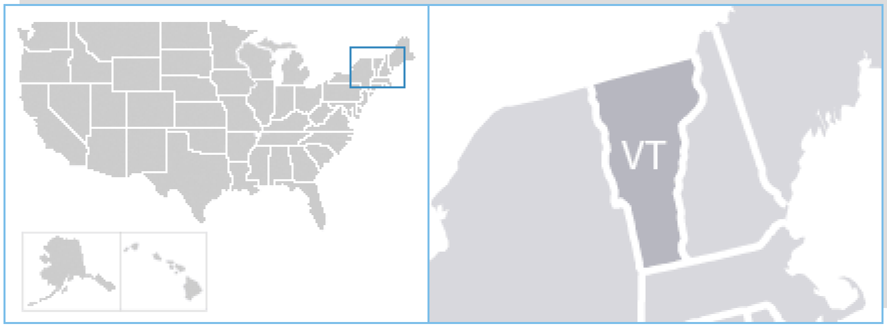


The CHP market in Utah is somewhat favorable, though the state has seen very little new CHP activity recently. The state earned three out of a possible five points in ACEEE's *Scorecard*, reflecting several good in-place policies. The state has had only two new CHP projects between 2005 and 2010: a 4.6 MW natural gas-fired combustion turbine installed at the University of Utah and a 7.6 MW natural gas-fired combustion turbine at a copper refinery.

The biggest barrier to greater CHP deployment in Utah is economics. The state has relatively cheap electricity prices and few opportunities for developers to earn revenue on excess power generation, though it does have good in-place interconnection standards. Utah's net metering regulations only allow for systems up to 2 MW, and only those that use waste gas or waste heat—not new CHP systems. The state does not have a true RPS in place, but instead has a voluntary Energy Resource and Carbon Emission Reduction Initiative, which requires only that the state's regulated utilities pursue renewable energy resources to the extent that it is "cost-effective" to do so. For the purposes of the initiative, waste heat and waste gas count as eligible renewable resources.

Rocky Mountain Power Company, the largest utility in the state, has been a "decent" partner in CHP and other distributed generation projects, though it does not have favorable standby rates for CHP projects, which can further hamper a project's economics. Supporters do see some promise in future applications in the industrial and institutional sectors, and believe that, unlike other Southwest states, Utah is not dominated by wind or solar interests in discussions about alternative energy strategies. Developers and supporters remain hopeful that Utah will see an increasing amount of CHP in the future.

VERMONT



New CHP Sites (2005-2010):
10 sites (#9)

New CHP Capacity (2005-2010):
3.2 MW (#34)

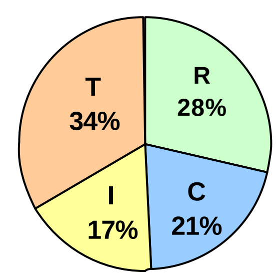
Average Capacity per Site (2005-2010):
0.3 MW

Total Primary Energy Consumption (2008):
154 trillion Btu (#51)

Average Gas Price (2009):
$12.73 per MCF (#9)

Average Electricity Price (2010):
13.16¢ per kWh (#11)

Energy Consumption by Sector



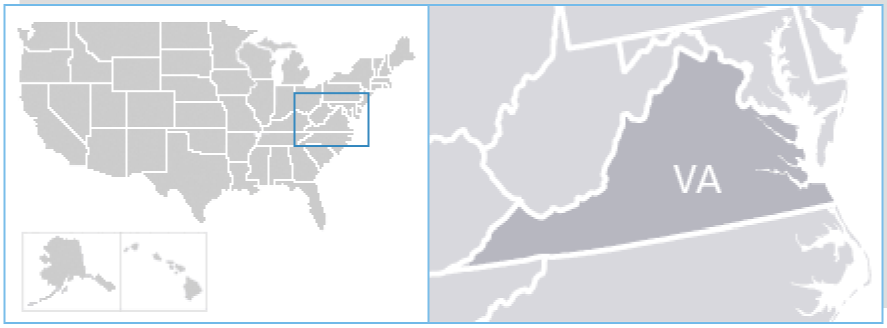
The CHP market in Vermont is only slightly favorable, and the market suffers in general from cheaper electric rates and resultant poor economics for projects. The state received three out of a possible five points in ACEEE's *Scorecard*, and has seen the deployment of ten small CHP projects between 2005 and 2010, totaling 3.2 MW of installed capacity.

Despite Vermont's long history as a leader in energy efficiency policies, numerous barriers to CHP remain. Though the state's interconnection standard is considered good, non-utility generators that wish to sell excess power must also satisfy lengthy siting rules (VSA 2009). These are widely viewed as "onerous," and representative of the "Not-In-My-Backyard" mentality that can prevent DG in Vermont.

Electric rates in Vermont are low for the region, due to long-term contracts with nuclear and hydro facilities that expire soon. The expiration of these contracts is expected to cause a rise in the state's electric rates, which could lead to greater CHP deployment. But for now, few projects are making economic sense. "If it were my buck, I don't think I'd put [CHP] in here," said a developer. The state lacks many industrial and commercial hosts with high thermal loads. The CHP that is built "relies on subsidies to make sense." Natural gas, which could be a cost-effective fuel for CHP in the state, is found only in the northwestern portion of the state along Lake Champlain. A recent study found only 74 MW of economic CHP potential in the state and that proximity to natural gas infrastructure helped greatly to make CHP projects economic (VSPC 2010). CHP projects in the rest of the state rely on biomass or other nearby fuel sources. More developers are taking advantage of available biomass and wood-based fuel sources for CHP projects in the state, helped by incentives for those fuels.

CHP has not had a solid "home" in Vermont's energy efficiency efforts, due largely to CHP's higher cost per kWh than other efficiency measures. A new feed-in-tariff, enacted in 2009, offers substantial incentive for CHP projects fueled by biomass. The response from biomass CHP projects interested in earning revenue from the feed-in-tariff has been immense, indicating that strong interest in these projects exists in Vermont. However, without the feed-in-tariff in place, the projects would not be economically sound on their own. It is likely that CHP will remain a less prioritized energy resource in the state, though incentives for biomass-powered renewable energy projects will continue to encourage biomass-fueled CHP.

VIRGINIA



New CHP Sites (2005-2010):
3 sites (#26)

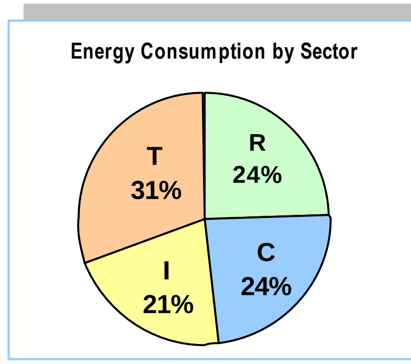
New CHP Capacity (2005-2010):
0.1 MW (#44)

Average Capacity per Site (2005-2010):
0 MW

Total Primary Energy Consumption (2008):
2,514 trillion Btu (#14)

Average Gas Price (2009):
$12.15 per MCF* (#13)

Average Electricity Price (2010):
8.78¢ per kWh (#27)



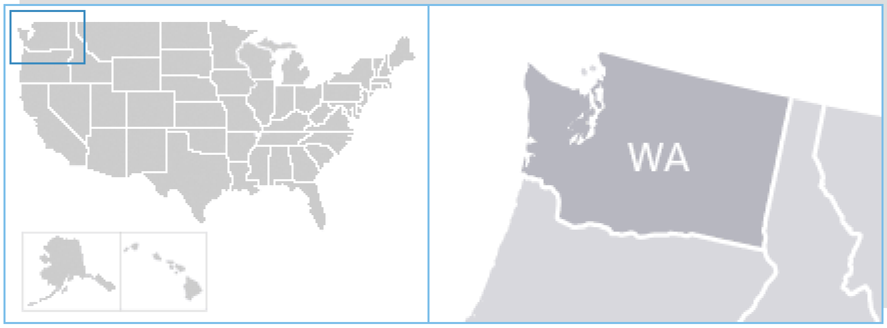
The market for CHP in Virginia is not favorable. The state earned the lowest possible score in ACEEE's *Scorecard*, and deployed three small CHP projects between 2005 and 2010, representing a total installed capacity of 120 kW.

Economics serves as the biggest barrier to greater CHP deployment in Virginia. Electricity remains cheaper than the U.S. average, and CHP projects face no source of revenue for excess power. Unfavorable standby rates also have hurt the economics of potential CHP projects in the past. Institutions appear to be the biggest opportunity for CHP in the state, in part because "sustainability" and "green" mandates have helped justify CHP's added cost. This has been particularly true for federal government buildings, which have recently been tasked with reducing greenhouse gas emissions.

Some small points of progress have been made in the past few years. An interconnection standard that allows for CHP systems up to 20 MW has been established. In 2010, the State Corporation Commission began to approve energy efficiency plans developed by Virginia's regulated utilities, and the state has adopted electricity reduction goals. However, no portfolio standards are in place, and no other mechanisms to incentivize utilities to encourage CHP projects among their customer base exist.

Air quality regulations still appear to be another big barrier to greater CHP deployment in Virginia. The state has no output-based emissions standards, and developers have found it hard to overcome the more stringent air emissions regulations in the state's non-attainment areas, which generally cover the entire Washington, D.C.-metro area in northern Virginia. Air quality regulations that fail to give credit for the increased efficiency of CHP can add substantial cost to CHP projects, and Virginia does not appear to have a CHP market that is healthy enough to weather those costs.

WASHINGTON



New CHP Sites (2005-2010):
8 sites (#14)

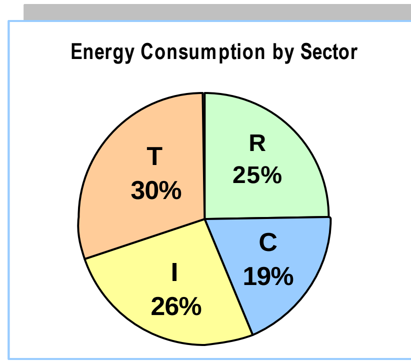
New CHP Capacity (2005-2010):
97.6 MW (#6)

Average Capacity per Site (2005-2010):
12.2 MW

Total Primary Energy Consumption (2008):
2,050 trillion Btu (#17)

Average Gas Price (2009):
$12.58 per MCF (#11)

Average Electricity Price (2010):
6.54¢ per kWh (#50)



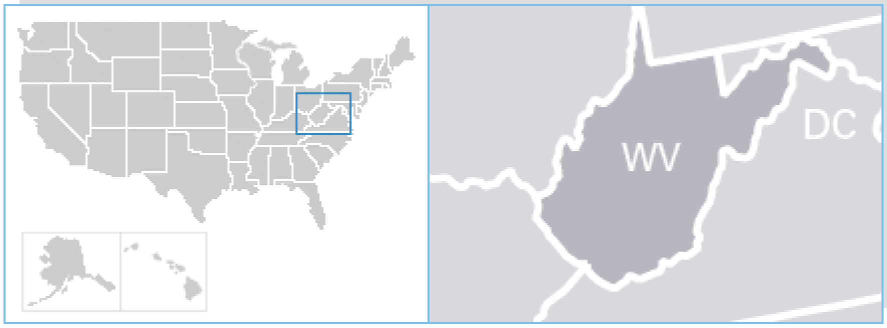
The CHP market in Washington is somewhat favorable. The state earned four out of a possible five points in ACEEE's *Scorecard*. Between 2005 and 2010, Washington saw the installation of eight new CHP projects, representing a combined installed capacity of nearly 98 MW.

The biggest barrier to increased CHP deployment in Washington is economics. Washington's electricity is among the cheapest in the nation, thanks to substantial hydropower resources throughout the state. The general spark spread is bad, interconnection costs are high and uncertain, and avoided cost payments made under PURPA are low. In fact, some Washington-based generators choose to sell into the Idaho market due to Idaho's substantially higher avoided cost payments.

Several new policies could serve the Washington CHP market well, but they appear to be doing little to actually move the market at present. Initiative 937, passed by Washington voters in 2006, established a Renewable Energy Standard (RES) and stipulated that utilities must pursue all cost-effective conservation. Certain types of CHP count as eligible renewable energy resources, such as biomass. However, developers note that wind power resources have thus far "eaten up" the RES goal (15% by 2020), leaving little incentive for utilities to pursue additional projects such as CHP. CHP will likely be better served by the initiative's requirement that utilities pursue all cost-effective conservation. This explicitly includes "high efficiency cogeneration" that is designed only to serve a customer's local load. Utilities' abilities to meet this goal will not be officially assessed until 2012, leaving developers unsure of how the CHP market will or will not be served by the new rules. An improved interconnection standard, adopted in 2007, is slowly making the process less cumbersome.

Aside from net metering for small (less than 100 kW) systems, Washington State itself does not offer any direct incentives for CHP. Several Washington utilities offer incentives for biomass or biogas-powered CHP within their renewable energy incentive programs, but none appear to offer incentives within their energy efficiency program offerings. Puget Sound Energy treats CHP as fuel switching, and thus does not offer its energy efficiency rebates to customers installing CHP systems. While no particular Washington utility was singled out for being helpful to CHP projects, utilities were not identified as a major barrier, either. With the further maturation of the RES and improved interconnection rule, Washington CHP developers may soon find themselves facing a growing interest in CHP, particularly in biomass and waste energy recovery opportunities.

WEST VIRGINIA



New CHP Sites (2005-2010):
3 sites (#26)

New CHP Capacity (2005-2010):
0.6 MW (#41)

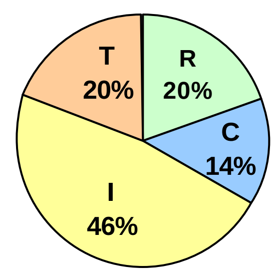
Average Capacity per Site (2005-2010):
0.2 MW

Total Primary Energy Consumption (2008):
831 trillion Btu (#33)

Average Gas Price (2009):
$11.44 per MCF (#19)

Average Electricity Price (2010):
7.37¢ per kWh (#44)

Energy Consumption by Sector



The CHP market in West Virginia is unfavorable. The state only earned one point out of a possible five in ACEEE's *Scorecard*, and has seen the installation of three new CHP systems between 2005 and 2010. However, those systems only represent 645 kW of total installed capacity.

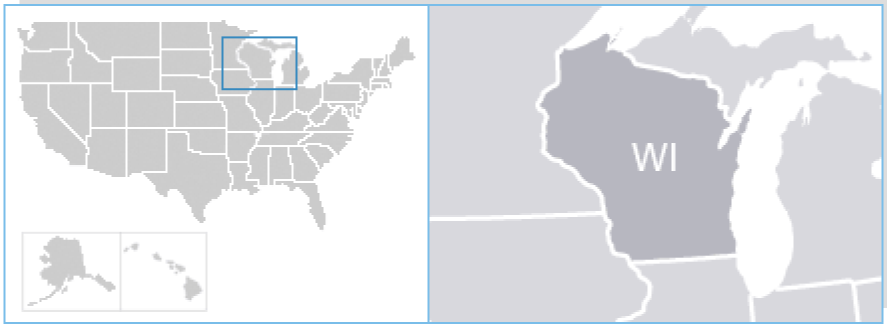
The primary barrier to greater CHP deployment in West Virginia is economics. "Power is so cheap" in West Virginia due to the state's near-exclusive use of coal-powered electricity. However, CHP and waste energy recovery are uniquely positioned to benefit from the unique definitions of "alternative" and "renewable" energy in West Virginia's Alternative and Renewable Energy Portfolio Standard. The state's standard counts waste heat as a renewable resource, and natural gas, synthetic gas, and other fossil fuels as alternative energy resources. Though these designations can help the CHP market in the state, the standard does not carry any penalty for non-compliance by utilities until 2015. So developers do not yet have a sense of what the precise impact of the portfolio standard will be.

Waste energy opportunities are often plentiful in the industrial sector, and the state's industrial energy assessment team is "as busy as they can be" working to meet the need of industrial energy assessments. Waste energy recovery is one of the items the team considers in its assessments, and they expect more waste energy recovery opportunities to present themselves as the state looks to further incentivize the capture and productive use of waste energy.

West Virginia offers no financial incentives for CHP. One promising waste energy project in West Virginia, a 65 MW installation at a silicon plant, is relying on ARRA funds to move forward. Barring the awarding of those funds, the project will likely not move forward. There appear to be few other projects currently being considered for near-term deployment in the state.

West Virginia has made some recent progress. In addition to the alternative energy portfolio standard, a new, improved interconnection standard for distributed generation, including CHP, has been adopted. However, the standard only applies to systems up to 2 MW in size. Additionally, West Virginia's utilities have not been very active in encouraging CHP among their customers, but American Electric Power is viewed as slightly more amenable to CHP projects than Allegheny Power. It is clear that there remains very little incentive for any of West Virginia's utilities to actively support greater CHP deployment.

WISCONSIN



New CHP Sites (2005-2010):
20 sites (#6)

New CHP Capacity (2005-2010):
83.0 MW (#8)

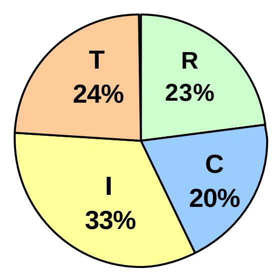
Average Capacity per Site (2005-2010):
4.2 MW

Total Primary Energy Consumption (2008):
1,862 trillion Btu (#21)

Average Gas Price (2009):
$9.41 per MCF (#32)

Average Electricity Price (2010):
9.75¢ per kWh (#20)

Energy Consumption by Sector



The CHP market in Wisconsin is relatively favorable. The state received a score of four out of five in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Wisconsin installed 20 new CHP systems with a combined capacity of 83 MW.

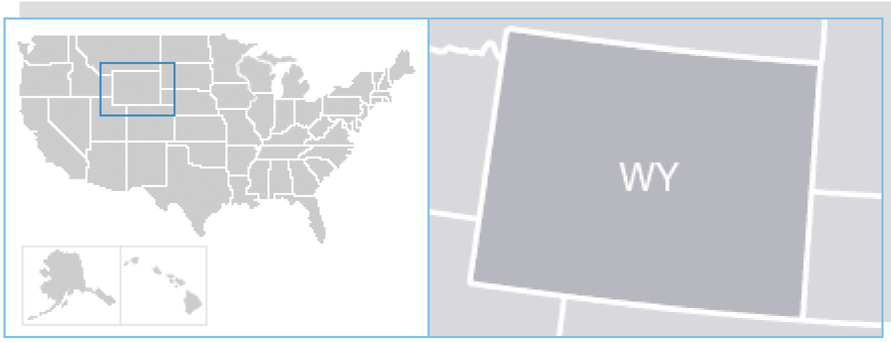
Wisconsin does not have extremely high electricity rates compared the rest of the country, but it does have the highest rates in the Midwest region. However, developers still point to the spark spread in Wisconsin as the biggest barrier to CHP development. Because the state has an abundance of coal power and nuclear power, has made large investments in transmission capacity, and has seen a significant drop in base load demand due to the economic recession, there is no shortage of power and reliability is not an issue.

According to one stakeholder in Wisconsin, customers are investing in efficiency, but not in generation, with the exception of cases where there is an opportunity fuel or substantial infrastructure already in place. Industry there is currently seeking a two-year payback, or three at the most. Institutions are typically open to longer payback periods, up to around eight years, because they are interested in thermal projects for more environmentally-focused reasons. The commercial sector in Wisconsin has simply not exhibited the desire to take on generation projects.

Supporters in Wisconsin suggest that potential hosts, lawmakers, and regulators are still leery of natural gas, despite it being relatively cheap at present. There are currently no financial incentives for CHP in place, though there are a number of incentives for renewable energy, including favorable "green" electricity rate structures, which have been capitalized by some CHP applications, including anaerobic digesters and biomass systems.

While no utilities in Wisconsin were pointed to as significantly interested or helpful for CHP development, they are also not seen as substantial barriers. Alliant Energy, one of the states IOUs, has established a shared savings program for certain CHP systems, and one advocate regards Wisconsin utilities as having "bought into" many of the programs in place for CHP. Interconnection procedures and utility standby rates were not cited as barriers to CHP in Wisconsin.

WYOMING



New CHP Sites (2005-2010):
2 sites (#34)

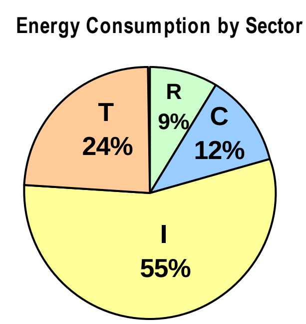
New CHP Capacity (2005-2010):
0.4 MW (#43)

Average Capacity per Site (2005-2010):
0.2 MW

Total Primary Energy Consumption (2008):
542 trillion Btu (#40)

Average Gas Price (2009):
$7.53 per MCF (#46)

Average Electricity Price (2010):
6.20¢ per kWh (#51)



The CHP market in Wyoming is very unfavorable. The state has consistently received the lowest possible score in the CHP chapter of ACEEE's 2010 *Scorecard*. Between 2005 and 2010, Wyoming installed two new CHP systems with a combined capacity of 0.4 MW.

The main barrier to greater CHP deployment in Wyoming is economics. Wyoming has, on average, the lowest electricity rates in the country. Such low rates make it difficult for businesses to justify investing upfront capital in CHP systems, as payback periods are generally too extensive for projects to be worth undertaking. With such a large percentage of Wyoming's electricity consumption occurring in the industrial sector but such unfavorable payback periods for industrial projects, it is not surprising that so few projects have been developed in the state.

A 110 MW system installed at an Exxon Mobil facility in 2004 is by far the largest CHP system operating in the state. In this case, the system, located at a fossil fuel extraction facility, is being used to support an existing electric load. Its large capacity places it at the wholesale market level of regulatory jurisdiction.

Regulatory barriers do not seem to pose a problem in Wyoming, as few projects reach the point of dealing with regulations. Similarly, electric utilities are not actively opposed to projects as there are so few new ones and existing projects impact such a small amount of electricity consumption. New energy efficiency programs at the state's largest utility, Rocky Mountain Power, are currently ramping up, and show a trend toward greater support for energy efficiency programs in the state.

Conclusion

The CHP market in the U.S. is generally well developed with a significant number of adept project developers and equipment manufacturers primed to help transform the way power is generated in the U.S. Though the current economic downturn has stalled much CHP activity for the moment, there remain a great number of untapped opportunities for CHP across all sectors of the economy.

In states that have worked aggressively to remove barriers to CHP, developers have been able to continually identify new, sound projects and take advantage of programs designed to move CHP closer to the mainstream. However, removing regulatory barriers and offering financial incentives can only go so far. The public in general needs to be better educated about the benefits of CHP, and outreach to the sectors that are best suited for CHP should be an integral component of any CHP policy effort. CHP needs to be treated as a prioritized generation resource in order for developers and owners to be able to realize the full economic benefits of operating efficient CHP systems. Such treatment is dependent upon the role utilities and their regulators want CHP to play. What can various stakeholders do?

Business Owners

Business and facility owners, who are less willing to take on new debt at the moment, may find it to be in their best long-term interest to consider CHP for their facilities. Remaining open-minded about adopting projects with longer payback periods may behoove business owners, who could be locking in cheaper, more efficient power for years.

Utilities and Utility Shareholders

For some utilities, particular those that offer both electric and gas services, CHP can be a true boon to business. In states where some cost recovery mechanism for electric energy efficiency is offered to these utilities, the electric side of the company does not lose with CHP, and the gas side can benefit when the CHP is gas-fired. And yet, what would benefit the company and shareholders overall—greater deployment of CHP, particularly gas-fired CHP—is often not encouraged on the electric side, where business practices might actively work against greater CHP deployment. Shareholders would do well to consider how alternative energy resources might, in fact, benefit a utility company long-term.

CHP Project Developers

CHP project developers would do well to identify internal project champions early on in project development. Working with one person directly, as a single point of contact for all issues associated with installing a new CHP system, can reduce paperwork and delays and other factors that add to project costs.

Project developers need to act as a key source of education for future CHP owners. Absent education from a state energy office or local utility, it is incumbent on the project developer to help a future CHP owner fully understand and take advantage of the variety of existing CHP system structures, and the various financial incentives available to help move projects forward.

CHP Supporters

CHP supporters play a critical role in identifying policy and regulatory barriers and working to remove them. In each region, a handful of organizations, usually nonprofits, participate in advocating for CHP-friendly policies. However, these organizations also operate with limited staff and funding, limiting their impact. What is clear is that any and all policies that support CHP at the state level have been a result of dedicated CHP supporters and developers working to educate regulators and other decision-makers about the benefits of CHP. Policies that support CHP do not appear to develop organically, and CHP supporters should continue to reach out to stakeholders to break down the barriers facing CHP in their state or region.

State Utility Regulators

Regulators are in a unique position to dramatically impact the CHP market in their states. By identifying energy efficiency as a primary resource to meet future energy demand, they can help set the stage for CHP and other efficient sources of power. By giving utilities and other entities tasked with acquiring efficiency resources the flexibility and freedom to support long-term CHP programs, regulators are helping their local CHP market mature and be viewed as reliable by CHP developers. Once developers are confident that CHP systems will be welcomed for the long term in a given state, it is clear that they work hard to educate future consumers about CHP, maximizing the positive impacts the highly efficient systems can make. Regulators are essential to laying out the welcome mat.

Developing CHP programming that best suits local needs is fundamentally important for a state's CHP market growth. Proper policy can be more important than direct subsidy in some cases, as good policy helps the market help itself. Carefully designed programs that target market transformation opportunities and not just the most or quickest installed capacity can make the most of the limited funding states have to support such projects. Market transformation projects that help program administrators "teach marketplace actors and fix institutional barriers" are good uses of program dollars.

State Legislators

State legislators have historically set long-range goals for efficiency and renewable energy savings, and influence the goals regulators set for regulated utilities. They can also, importantly, set efficiency and renewable energy goals and financial incentive levels for public and municipal utility districts, which are largely exempt from regulation by state utility regulators. This is crucial, as municipal utility districts often include large industrial and commercial loads, which are well-suited to CHP. State lawmaking bodies can also require CHP feasibility assessments to be made prior to new construction, and that public buildings deploy CHP whenever appropriate. For these reasons, state lawmakers can play a critical role in encouraging CHP. They can also heavily influence public perceptions of energy resources and encourage increased efforts to educate the public about the benefits of CHP.

Federal Government

A suite of robust federal policies could significantly strengthen the national CHP market. Dozens of bills have been introduced in the U.S. Congress with the aim of enhancing CHP deployment, with provisions that have included tax credits, national standards for interconnection procedures, and net metering. Other bills that have been introduced to address barriers to CHP or further encourage its development have often been met with bipartisan support, but have stalled in the houses of Congress.

Two federal agencies have historically supported CHP: the Department of Energy and the Environmental Protection Agency. Both agencies continue to fund programs that encourage CHP deployment around the country. The EPA recognizes superior CHP projects through the Energy Star CHP Awards and promotes CHP through the CHP Partnership Program. DOE, through its Regional Clean Energy Application Centers, promotes market transformation efforts in states throughout the U.S.—educating potential end-users in high opportunity sectors, educating policymakers on how CHP-favorable policies can benefit their state, and providing local support to help move projects forward. Additionally, DOE supports critical national research and development on CHP technologies. According to CHP developers and supporters, these programs have been tremendously beneficial to the CHP community. However, they also note that CHP is still not widely known to be a federal priority, and that these agencies could do more to influence their counterparts on the state level.

One federal program addresses the fact that certain CHP technologies are still viewed as "emerging" by would-be investors, and are viewed as riskier investments than other, more widely understood alternative energy investments. The EPA and the DOE recently expanded their ENERGY STAR program by adding an Emerging Technology category for its 2011 ENERGY STAR product awards. For the inaugural year of the Emerging Technology award, the program chose micro-CHP as its target emerging technology, offering an instrumental vote of confidence to the technology that is just now entering the American marketplace.[6] Micro-CHP developers have noted that the ENERGY STAR brand lends a degree of authority to micro-CHP, which helps overcome certain barriers inherent in the deployment of new technologies.

There are other areas that may be appropriate for federal leadership to help move CHP into the mainstream. Several developers cited the fact that CHP has no clear role in most large-scale sustainability initiatives. It is not always an integral component of energy efficiency planning, nor is it always embraced by renewable energy supporters. CHP also does not always fit neatly into existing efficiency standards. While CHP can receive particular credits in the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) certification system, the also-popular National Association of Homebuilders' National Green Building Standard gives credit for energy efficiency measures but does not specifically call out CHP as a way to earn "points" towards higher certification levels. These kinds of differences among standards leaves CHP developers confused about how CHP can fit into "green building" goals. Such clarity is critical to building owners, because institutions, such as school districts or hospitals, are often held to "green building" standards for new construction by their boards or regulators, and new buildings must often meet these standards in order to receive municipal, county, or state funding, or tax benefits awarded to "green" buildings.

Developers, supporters, regulators, legislators, consumers, and the federal government can all impact the CHP market. Individuals interested in promoting CHP must continue to work to remove barriers and educate lawmakers and regulators about its benefits. Developers, equipment manufacturers, and CHP supporters have the tools necessary to make the power generated in the U.S. much cleaner and more efficient. Everyone has a role to play.

In addition, a need for additional education and a building of greater awareness remains. The CHP community has made important progress over the past decade and a half in increasing awareness among policy makers and to a lesser extent by the public. CHP systems, and their economic and markets are complex in contrast to many other efficiency technologies where you just plug in a new light bulb. As a result, the CHP community must continue to tell the CHP story and highlight the benefits of successful CHP projects.

[6] For more information about ENERGY STAR's new Emerging Technology award, visit: http://www.energystar.gov/index.cfm?c=pt_awards.pt_emerging_technologies.

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APPENDIX

State	New CHP Sites (2005-2010)	Rank	New CHP Capacity, MW (2005-2010)	Rank	Average Capacity per Site, MW (2005-2010)	Total Primary Energy Consumed, TBtu (2008)	Rank	Average Gas Price per MCF (2009)	Gas Price Notes	Rank	Average Electricity Price, ¢ per kWh (2010):	Rank
Alabama	3	26	47.0	11	15.7	2,065	16	$13.41		7	8.97	26
Alaska	1	43	0.4	42	0.4	651	39	$7.76		42	14.84	5
Arizona	2	34	16.3	20	8.1	1,553	24	$12.67		10	9.86	19
Arkansas	2	34	5.3	30	2.7	1,125	31	$10.87		25	7.30	45
California	**140**	1	120.6	3	0.9	8,381	2	$7.87		40	14.07	9
Colorado	9	11	10.7	26	1.2	1,498	25	$8.12	C and R	38	9.34	22
Connecticut	62	3	186.4	2	3.0	810	34	$11.06		22	17.44	2
Delaware	0	45	0.0	45	0.0	295	47	$15.75		3	11.99	14
District of Columbia	0	45	0.0	45	0.0	180	50	$13.98	R only	6	13.84	10
Florida	3	26	43.9	12	14.6	4,447	3	$11.02	C only	24	10.57	15
Georgia	4	19	2.9	35	0.7	3,015	9	$11.86		17	9.03	25
Hawaii	3	26	1.9	37	0.6	284	48	**$28.47**		1	**24.91**	1
Idaho	2	34	3.8	32	1.9	529	41	$10.28	C and R	27	6.57	49
Illinois	9	11	104.8	4	11.6	4,089	4	$8.34		37	9.23	23
Indiana	8	14	2.2	36	0.3	2,857	11	$8.76		34	7.66	40
Iowa	3	26	16.9	19	5.6	1,414	28	$7.88		39	7.77	37
Kansas	4	19	16.0	21	4.0	1,136	30	$8.50		36	8.29	34
Kentucky	0	45	0.0	45	0.0	1,983	18	$9.51		31	6.71	48
Louisiana	0	45	0.0	45	0.0	3,488	8	$8.76	I and R	35	7.85	36
Maine	2	34	4.5	31	2.2	469	42	$14.35		5	12.73	13
Maryland	2	34	7.0	28	3.5	1,447	27	$11.86		16	12.84	12
Massachusetts	34	4	41.8	13	1.2	1,475	26	$16.81	I and R	2	14.65	7
Michigan	4	19	3.2	33	0.8	2,918	10	$10.14		29	10.13	17
Minnesota	9	11	12.2	23	1.4	1,979	19	$7.52		47	8.43	33
Mississippi	3	26	0.9	39	0.3	1,186	29	$7.69	I and C	43	8.66	29
Missouri	1	43	10.7	25	10.7	1,937	20	$11.03		23	7.95	35
Montana	4	19	17.6	17	4.4	434	44	$9.32		33	7.77	37
Nebraska	2	34	72.0	10	36.0	782	36	$7.65	I and R	44	7.60	41
Nevada	2	34	9.2	27	4.6	750	37	$11.79		18	10.04	18

State	New CHP Sites (2005-2010)	Rank	New CHP Capacity, MW (2005-2010)	Rank	Average Capacity per Site, MW (2005-2010)	Total Primary Energy Consumed, TBtu (2008)	Rank	Average Gas Price per MCF (2009)	Gas Price Notes	Rank	Average Electricity Price, ¢ per kWh (2010):	Rank
New Hampshire	4	19	0.8	40	0.2	311	46	N/A	N/A	N/A	14.75	6
New Jersey	18	7	14.1	22	0.8	2,637	13	$11.31		20	14.88	4
New Mexico	0	45	0.0	45	0.0	693	38	$7.18		49	8.60	30
New York	101	2	102.8	5	1.0	3,988	5	$12.27		12	16.46	3
North Carolina	13	8	17.6	18	1.4	2,702	12	$11.30		21	8.78	27
North Dakota	4	19	23.0	15	5.8	441	43	**$7.02**		50	7.02	47
Ohio	8	14	94.6	7	11.8	3,987	6	$10.26	I and C	28	9.15	24
Oklahoma	0	45	0.0	45	0.0	1,603	23	$12.09		15	7.59	42
Oregon	10	9	38.8	14	3.9	1,105	32	$12.91	C and R	8	7.55	43
Pennsylvania	25	5	80.9	9	3.2	3,900	7	$12.10		14	10.42	16
Rhode Island	7	18	1.6	38	0.2	220	49	$14.93		4	14.20	8
South Carolina	3	26	6.0	29	2.0	1,660	22	$10.65	I and R	26	8.49	32
South Dakota	4	19	21.5	16	5.4	350	45	$7.54		45	7.76	39
Tennessee	0	45	0.0	45	0.0	2,261	15	$9.58		30	8.54	31
Texas	8	14	**380.8**	1	47.6	**11,552**	1	$7.82		41	9.44	21
Utah	2	34	12.1	24	6.1	799	35	$7.36		48	7.10	46
Vermont	10	9	3.2	34	0.3	154	51	$12.73		9	13.16	11
Virginia	3	26	0.1	44	0.0	2,514	14	$12.15	C and R	13	8.78	27
Washington	8	14	97.6	6	12.2	2,050	17	$12.58		11	6.54	50
West Virginia	3	26	0.6	41	0.2	831	33	$11.44		19	7.37	44
Wisconsin	20	6	83.0	8	4.2	1,862	21	$9.41		32	9.75	20
Wyoming	2	34	0.4	43	0.2	542	40	$7.53		46	**6.20**	51

Key: **R** = Residential, **C** = Commercial, and **I** = Industrial