Coal Retirements and the CHP Investment Opportunity

Anna Chittum and Terry Sullivan

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529 14th Street NW, Suite 600, Washington, D.C. 20045
Phone: (202) 507-4000 • Twitter: @ACEEEDC
Facebook.com/myACEEE • www.aceee.org

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Contributors

Co-author Terry Sullivan completed this work while an intern with ACEEE. He is a candidate for a Master of Public Affairs at the University of Washington's Evans School of Public Affairs.

The foundational technical analysis and economic analysis of potential CHP deployment were conducted by ICF International for ACEEE. Ken Darrow, Anne Hampson, and Bruce Hedman were instrumental in shaping and executing the CHP potential analysis for all 12 states targeted in this report.

Executive Summary

The next two decades will see substantial changes in the way electricity is generated in the United States. As coal loses favor to natural gas and other alternatives, utilities will retire a significant portion of their coal fleet and invest substantially in other energy resources around the country. Energy efficiency, and combined heat and power (CHP) in particular, represents significant near-term opportunities to make highly cost-effective investments in new energy resources that can more cleanly and efficiently meet the nation's demand for electricity.

This report targets 12 U.S. states that for a variety of reasons look like particularly promising candidates for expanded CHP. It ascertains the likely amount of coal-fired electric capacity to be retired in the near term as well as the potential for natural gas-powered CHP to meet some of that lost capacity. It finds that, while CHP is not positioned to fully replace the lost capacity, it can play a substantial role in meeting these needs, especially in certain states. Table ES-1 indicates the percentage of lost coal capacity that could be met by new CHP installations. It assumes both a high estimate of coal retirements and a high degree of investment by utilities in CHP—encouraged by substantial developments in policies and regulations that would encourage such utility investment. It shows that most of the target states could potentially replace a significant portion of their retiring coal capacity with new cost-effective CHP systems, provided utilities have reason to make major investments in CHP.

Table ES-1: Estimated Percentage of Retiring Coal Capacity That Could Be Economically Replaced With New Combined Heat and Power (CHP) Systems, 2011–2020

State	Percentage Lost Coal Capacity Potentially Replaced with CHP
Alabama	51%
Colorado	19%
Georgia	40%
Indiana	21%
Iowa	2%
Kansas	100%
Kentucky	8%
Louisiana*	N/A
North Carolina	56%
Ohio	16%
South Carolina	100%
West Virginia	32%

*No coal retirements are planned for Louisiana

Sources: ICF 2012, FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d, see Appendix A and B

CHP, and energy efficiency in general, is cheaper and cleaner than any other energy resources. Policies and regulations do not always encourage CHP deployment, though, and this report finds that almost all of the states that are facing higher levels of potential coal retirements do not have most of the critical policies in place that yield a healthy investment environment for CHP.

This report also analyzes the impact on the CHP market of substantial investment by utilities, which are able to take a longer view of investments in capital expenditures and are thus able to accept longer payback periods than a typical industrial or commercial entity. It finds that investment by utilities would dramatically boost the amount of CHP deployed in the 12 target states, but that all of those states currently lack the policies and regulations that would encourage utilities to make such investments.

The opportunity for significant CHP investment is now. Major changes in the U.S. electricity market have already begun to appear, evident in the official reports and forecasts from the U.S. Energy Information Administration (EIA), which show coal losing substantial ground to natural gas in the country's current and future electricity generation. These changes are substantial and reflect a paradigm shift in how domestic energy resources are extracted and used in the U.S.

Coal as a commodity has increased in cost, while the primary alternative fuel, natural gas, has hit historic lows. The changing economics of coal generation over the past decade combined with an aging fleet and new regulations from entities like the U.S. Environmental Protection Agency (EPA) have put increased pressure on utilities with coal-fired electricity-generating plants to consider other generation options or invest in pollution controls at existing coal plants. Recent projections of the total impact of potential coal plant retirements vary considerably, reflecting the variations in assumptions about commodity and energy markets, the decision-making behavior of the nation's utilities, and the cost and stringency of new and future environmental regulations.

Two recent studies from the Bipartisan Policy Center and the EIA put the range of total national retirements at 29–35 gigawatts (GW) and 19–45 GW, respectively. While estimates vary widely, it is generally accepted that states heavily dependent on coal will see some coal retirements in the near future. Only particular regions are expected to see significant retirements, primarily the areas covered by the Midwest Independent System Operating (MISO), which covers the majority of Minnesota, Iowa, Wisconsin, Illinois, Indiana, and Michigan; the Energy Reliability Council of Texas (ERCOT), which covers Texas; and the PJM Interconnection, which covers the majority of Pennsylvania, New Jersey, Delaware, Ohio, West Virginia, Maryland, Virginia, and the District of Columbia (Celebi et al. 2010).

Though concerns about electric system reliability have been raised, it appears that these retirements have been anticipated early enough and are minimal enough that reliability concerns will be mostly mitigated (Macedonia et al. 2011). So too have stakeholders voiced concerns about the overall cost of plant retirements and pollution controls. These conversations have largely ignored an alternative that could meet future demand needs, reduce emissions, and save consumers money: energy efficiency. Energy efficiency offers other benefits in addition to its low cost, however. It reduces overall emissions; can be deployed quickly compared to traditional generation; reduces peak demand, minimizing the need for peaking plants; and reduces the general stress on vulnerable parts of the distribution system (Hayes and Young 2012).

So instead of cause for alarm, these retirements can be looked at as a unique opportunity to replace what were already old, comparatively inefficient, and dirty electricity generation assets with cleaner, more cost-effective resources. Well-considered investments in energy efficiency resources such as CHP can help utilities meet future demand while reducing overall emissions and costs borne by consumers as well as society at large.

Estimates of the overall level of investment to be spent on updating or replacing affected coal plants range from $70–180 billion (Celebi et al. 2010, FBR 2010). Utilities will bear a large share of the costs, but they will, as with other investments, pass that burden along to consumers through rate increases that reflect the levels of investment. The investment decisions made by utilities in the next few years will have ramifications for generations, as electricity generation assets tend to have long lives. It is thus imperative that decisions are made with the long-term interest of the nation in mind.

Of all energy efficiency options, CHP is uniquely suited to quickly and cost-effectively meet the needs of states facing imminent coal retirements. The levelized cost of a new 20 MW natural gas-powered CHP system is about 6.0 cents/kWh, while a new natural gas-powered combined cycle gas turbine system ranges from 6.9–9.7 cents/kWh. New nuclear generation is estimated at 7.7–11.3 cents/kWh. In addition to its cost benefits, CHP can be deployed more quickly than traditional general systems and is sited at or near customer loads, reducing transmission and distribution losses. CHP is also far more efficient than most separate generation of electricity and thermal energy, generating both at total efficiencies of 65–80 percent while traditional electricity generation in the U.S. is about 33 percent efficient.

The U.S. has seen slow but steady growth in CHP deployment recently. In 2011, only 110 new CHP systems were installed nationwide, totaling about 569 MW of new capacity. Tremendous potential remains. An Executive Order issued in September 2012 by President Obama codifies a goal of 40 GW of newly installed CHP by 2020—up from just over 82 GW in operation today. In just the twelve states targeted in this report, we find an aggregate of 57.6 GW in technical potential exists *today*. This is well above even the high range estimates of likely nationwide coal retirements. But given current policies and recent CHP installation trends, it appears taking advantage of that technical potential could be a challenge.

Some CHP markets are more promising than others. About 60 percent of the new capacity installed in 2011 was in Texas, Louisiana, New York, and California. Ohio, Massachusetts, and other states have recently begun to prioritize CHP as a clean and cost-effective energy resource. But most states could do much more to encourage CHP, including finding ways to better involve utilities as partners in CHP projects.

Electric utilities have not played a substantial role in the deployment of new CHP systems. This is due primarily to the fact that their businesses are not structured to provide a return on investments in

CHP—either by the utility itself or by customers at their own sites. Consequently utilities have typically been less than enthusiastic in identifying and supporting new CHP projects.

Since CHP systems take upwards of five or more years to pay back their initial investment, utilities are often better positioned financially to make these kinds of investments than an individual commercial or industrial entity. Facilities that invest in CHP need to be able to take a long view of investments and be comfortable with payback periods of five or six years. Utilities already are comfortable with such long-term investments and could invest in CHP to a substantial degree in the states most at risk for significant coal retirements. Cost-recovery mechanisms and other tools that already exist in the regulatory toolbox could be adapted to encourage major utility investments in CHP.

The retirement of coal plants around the country is a tremendous opportunity to invest in CHP and energy efficiency in order to lock in low rates and clean energy for generations. New CHP systems could help meet future electric demand at a cost far less than new natural gas plants or coal plants with newly required pollution controls. The obstacles to greater CHP deployment are not technical in nature, but ones that are rooted in policies and regulations. It is entirely within the capability of utilities today to make substantial investments in CHP—provided new policies and regulatory structures are put in place to encourage them to do so.

Introduction

The next two decades will see substantial changes in the way electricity is generated in the United States. These changes have already begun to appear, evident in recent versions of the U.S. Energy Information Administration (EIA)'s monthly and annual reports, which have revealed coal's share of the country's electric-generating capacity to be dropping steadily in favor of natural gas and renewable resources (EIA 2012a). In fact, during two months in 2011, the share of U.S. power generation fueled by coal dropped to 39 percent—the lowest level since 1978 (Kennedy and Bradbury 2012, EIA 2012a). These changes are substantial and reflect a paradigm shift in how domestic energy resources are extracted and used in the U.S.

The changing economics of coal and natural gas generation over the past decade combined with an aging fleet and updated U.S. Environmental Protection Agency (EPA) regulations have put increased pressure on coal-fired electricity-generating plants to close. Recent projections of the total impact of this wave of coal plant retirements vary considerably, reflecting the variations in assumptions about commodity and energy markets, the decision-making behavior of the nation's utilities, and the cost and stringency of new and future EPA regulations. Estimates of near-term nationwide closures range from 19 GW to 49 GW, which is about 2–5 percent of the total U.S. electric generating capacity (EIA 2011a, EIA 2012a).

This report describes the unique opportunity for increased energy efficiency these retirements present, focusing especially on combined heat and power (CHP). The many forces impacting coal-powered electricity generation are summarized along with the various estimates of the likely amount of actual coal plants to be retired in the near future.

This report explores twelve states that have high degrees of likely coal retirements and/or high degrees of CHP potential. For each of these states, this report summarizes the coal plant retirement situation as well as the technical and economic potential for new CHP. We find that while CHP will not be able to make up for all of the lost capacity due to coal retirements, it can meet a substantial amount of that capacity need in a highly cost-effective manner for most of the analyzed states.

Though these retirements represent a small portion of the country's electricity generation, they can be looked at as a unique opportunity to replace what were already rather inefficient and dirty electricity generation assets with cleaner, more cost-effective resources. The investment decisions made by utilities in the next few years will have ramifications for generations because electricity generation assets tend to live long lives. It is thus imperative that we as a nation get this right.

While much has been made about the cost of coal plant retirements and coal plant pollution controls, the conversation has largely ignored a cost-effective alternative that could meet future demand needs, reduce emissions, and save consumers money: energy efficiency. Energy efficiency offers other benefits in addition to its low cost. It reduces overall emissions; can be deployed quickly compared to traditional generation; decreases peak demand, minimizing the need for peaking plants; and lowers the general stress on vulnerable parts of the distribution system (Hayes and Young 2012).

Our analysis finds CHP potential to be considerably higher in the target states when we assume a high degree of investment in CHP assets by utilities. Utilities are generally able to take longer views on investments than individual industrial or commercial facilities. They are thus well-equipped to make investments in systems such as CHP that may take five years or more to pay back the initial investment.

Finally, this report discusses whether any of the target states are currently structured to encourage their utilities to invest in CHP. It examines other policies in place in each state that are currently impacting new CHP deployment. It finds that most of the states that will be most affected by coal retirements have considerable room for improvement in their CHP policies and do not currently feature policies that encourage utility investment in CHP. This is significant because the economic potential for CHP is much higher in all 12 states when investment by utilities is assumed.

Research Scope and Goals

The goal of this research was to determine whether CHP could help meet some of the anticipated lost capacity due to coal retirements. CHP is typically more cost-effective, faster to deploy, and cleaner than traditional electricity generation. Investing in CHP instead of new centralized generation can help utilities keep costs down for ratepayers, reduce overall emissions, and help ensure the grid will not be stretched over capacity due to near-term coal retirements.

To meet this research goal, this report quantitatively answers three distinct questions for twelve target states:

1. How much coal-fired electric-generating capacity is expected to retire in the next two decades?
2. What is the technical potential in industrial, commercial, and institutional facilities for new natural gas-powered CHP to provide some of that lost capacity?
3. What is the economic potential in these facilities for new natural gas-powered CHP to provide some of that lost capacity?

This report also answers the following qualitative question for each of the twelve target states: what is the current policy and regulatory environment for CHP, and are utilities incentivized or encouraged to support its increased deployment?

Though electricity is transmitted across state borders and states do not rely solely on their own in-state electric-generating capacity to meet in-state needs, the likely coal retirement capacity and the potential CHP capacity are assessed on a state-by-state basis because utility- and CHP-focused policies are made at the state level. The state-by-state approach also reflects the fact that some federal air regulations are adapted differently for each state, with limits for certain pollutants varying from state to state.

Methods

To determine the range of likely coal retirements, we reviewed multiple estimates, presentations, and reports from nonprofit entities, the federal government, regional transmission organizations, investment banks and advisors, and affected utilities. Estimates were often available for regions or transmission areas as a whole but were more difficult to find at the state level. Three separate databases offered plant-by-plant retirement estimates, allowing us to assign plants to specific states in order to derive state-level retirement estimates. We included all retirements that were expected to occur prior to 2020.

Estimates of coal retirements continue to change with new information about regulations, commodity markets, and other factors. The estimates of coal retirements developed for this report are largely based on reports and other sources published in the spring and summer of 2012. Additional detail about assumptions made in developing these estimates can be found in the "Retirement Estimates" section on page 9.

We present coal retirement estimates as a range of possible capacity loss, reflecting the fact that no two sources anticipated the exact same amount of likely capacity loss for a given state. Instead of a single number, we present our best attempt at a reasonable and realistic range of likely capacity retirements for each target state.

To determine the technical and economic potential for CHP in each target state, we relied on technical analysis by ICF International. ICF determined the technical potential for each state based on a number of assumptions and based on the existing building stock and manufacturing activity in each state, with a 0.8 to 1.3 percent annual growth assumed in these markets. The economic potential is based on two plant ownership scenarios, or assumptions, that are described in greater detail in the "State-by-State Findings" section on page 17 and Appendix B on page 69.

In addition to the above, we reviewed a substantial number of reports from utilities and regulatory commissions around the country to better understand the current utility perspective on both coal retirements and CHP investments. We also engaged CHP stakeholders in each state to ascertain the degree to which CHP-focused policies and regulations are impacting the state's current CHP market.

The Current Status of Coal-Powered Electric Generation

For decades, major areas of the United States have relied heavily on coal for electric generation. Abundant and relatively cheap, coal has powered large swaths of the Southeast, Midwest, Mid-Atlantic, and western United States. However, in recent years a number of factors have converged to cause a decline in the use of coal for electric generation.

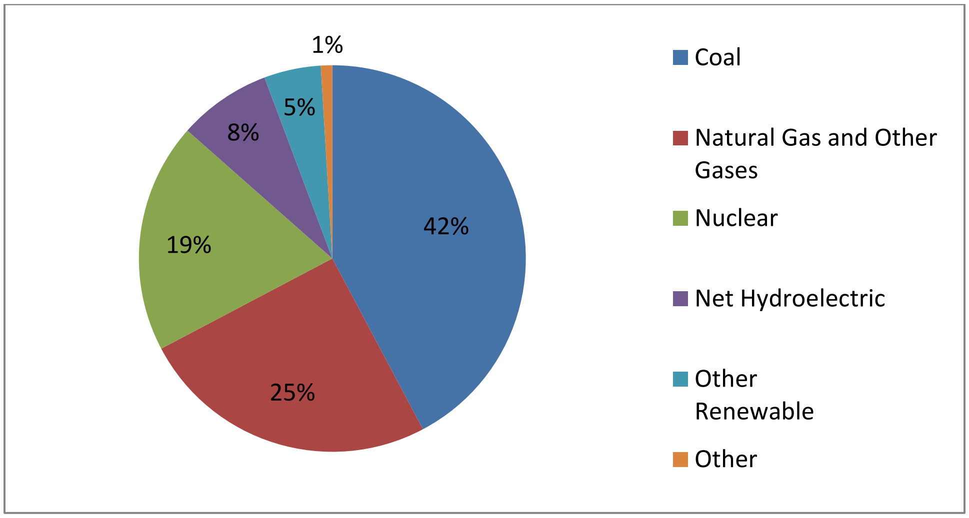
While coal remained the primary source of electricity generation in 2011—generating about 42 percent of U.S. electricity from over 1,400 generating units—the fuel mix is rapidly changing to include more natural gas, renewables, and energy efficiency. From over 48 percent as recently as 2008, the share of electricity generation from coal nationwide is projected by the EIA to decline to about 40 percent for 2012 (Kennedy and Bradbury 2012, EIA 2012a). Figure 1 shows the current share of electricity generation held by coal and other resources.

Coal is used for electricity generation disproportionately in certain states and regions. Figure 2 shows which states are most heavily coal-based in their in-state electricity generation. Wyoming and West

Virginia are the largest producers of coal in the U.S., and sit in the most coal-rich regions of the country. The states in those regions burn much of the coal that is mined nearby (EIA 2012d).

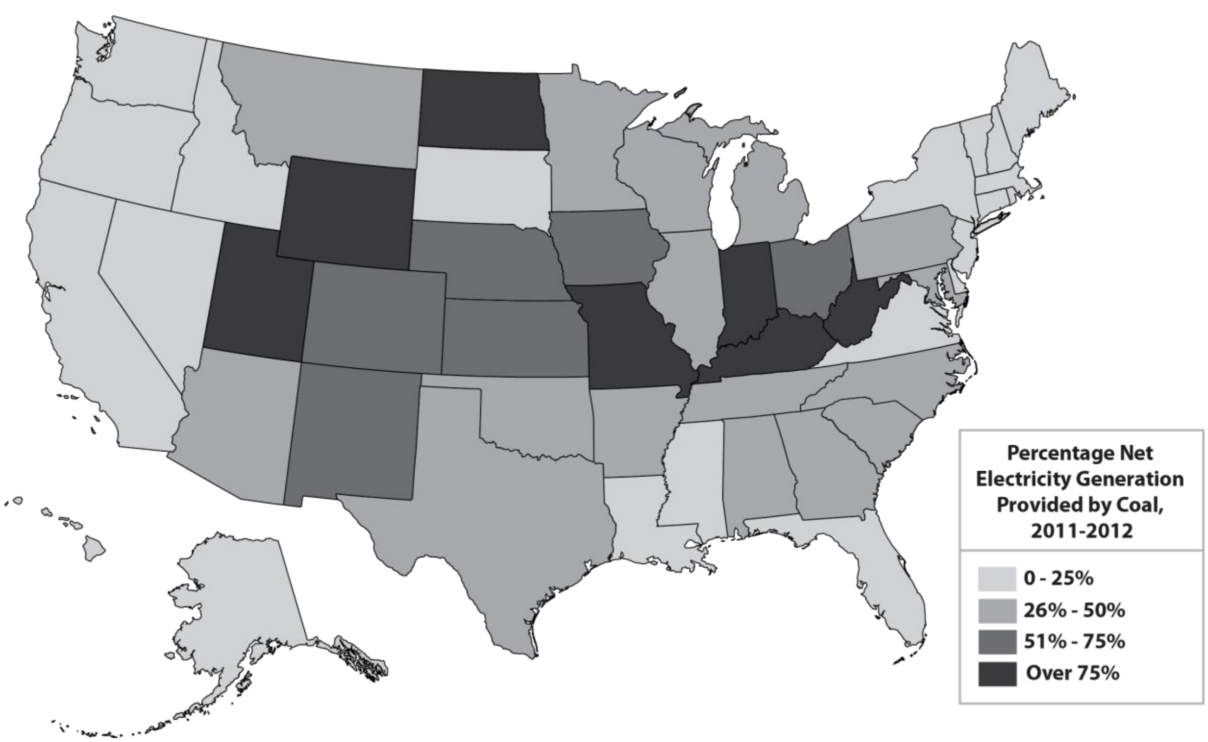
Coal is expected to continue to play a reduced role in U.S. electricity generation. The next sections will explain the many reasons for this trend.

Figure 1: U.S. Net Electric Generation, 2011



Source: EIA 2012a

Figure 2: Net In-State Electricity Generation Provided by Coal, June 2011–June 2012



Data Source: EIA 2012e

THE ECONOMICS OF COAL

For many reasons, coal has become less economically attractive for utilities to use to generate power. Though much has been made about the impact of new and impending EPA regulations, they are only one of several drivers impacting the turn away from coal. Utilities have been finding investments in coal harder to justify when compared to the economics of making investments in other generation resources such as natural gas.

The main reasons coal has become less economic are:

1. An aging coal electric generating fleet;
2. An increase in coal prices;
3. A steep reduction in natural gas prices;
4. Reduced electric demand; and
5. Anticipation of future air regulations (Tierney 2012, Elliott et al. 2011, Kennedy and Bradbury 2012).

The median age of a U.S. coal plant is 46 years old (Elliott et al. 2011). This is much older than the 30-year operating lifespan most plants were designed for. As a result, these plants have not been fully updated to modern operating standards and do not have certain pollution controls in place. Older plants also tend to be smaller, relatively inefficient, and do not operate at full capacity. This makes them even more uneconomic to operate, and investments in maintenance, pollution controls, or other modernization efforts are harder to justify. Costs vary little between plant sizes, so smaller units would need to compensate with greater revenue to make continued operation attractive, which may not be possible because they are used less often than larger, newer plants (PJM 2011).

The age of the coal fleet has combined with a decrease in the cost advantage of coal over its primary substitute, natural gas. The change began slowly from 2003-2007 with a slow increase in the cost of coal followed by a steeper incline after 2008 as the price of coal increased due to expanding demand worldwide. Adjusting for inflation, average annual coal prices have increased 70 percent since 2002 due primarily to increased demand for coal internationally and a reduction in coal mine productivity (Kennedy and Bradbury 2012, EIA 2011c). At the same time, the dramatic increases in domestic natural gas supply have led to a 10-year low for average monthly natural gas prices. In April 2012, the Henry Hub Gulf Coast Natural Gas spot price fell to $1.95/mmBtu, the lowest monthly average since 1999 (EIA 2012c), though prices have increased since then due to market forces (Young et al. 2012).

Beyond the impacts of changing commodity prices, utilities have seen a period of slowing electric demand. The recent recession and slow recovery have combined with rising energy efficiency goals and related programs to slow the growth of electricity consumption in recent years. After decades of high rates of electric demand growth, utilities have faced growth of less than one percent annually from 2000 to 2010 (EIA 2012a).

Many coal plants, especially older ones, are facing unfriendly economics due to the factors listed above and can anticipate even less favorable economics as new and updated environmental regulations exert pressure on some plants to retire.

REGULATORY CHANGES

The Clean Air Act was first codified in 1970 by the United States Congress, which concurrently created the EPA to help administer and enforce the new legislation. Under the authority of the Clean Air Act, the EPA regulates a wide variety of pollutants to help protect human life. Pollutants such as sulfur oxides (SO_2), nitrogen oxides (NO_2), mercury, and, more recently, carbon dioxide, are now regulated to varying degrees by the EPA. All of these pollutants are emitted by coal when it is burned to generate electricity.

The EPA is updating many of its federal rules pertaining to air, as well as rules affecting water and waste. These will directly impact electric generating plants in the near term (McCarthy and Copeland 2012). The George W. Bush administration EPA began a number of regulatory actions that pertain to electric power plants that the Obama administration EPA has continued and expanded, mostly under the Clean Air Act. After the 2007 Supreme Court decision, *Massachusetts v. EPA*, the EPA determined greenhouse gases endangered public health and welfare and were compelled to regulate them under the Clean Air Act. Thus, a large portion of the pollutants emitted by coal plants are now regulated by the EPA.

Though additional future rules will likely impact electricity generators, two rules are anticipated to impact the current fleets of coal plants in particular. The Cross-State Air Pollution Rule (CSAPR) and the proposed Mercury and Air Toxics Standards (MATS) were designed to replace two existing rules, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), respectively, which were initially proposed by the Bush administration. Both older rules were later sent back to the EPA by federal courts to comply with the Clean Air Act, and the Obama administration developed the two new rules to replace the flawed older ones.

The aim of the CSAPR rule is to control the emissions in certain states that impact other states' air quality and causes downwind states to fail to meet air quality standards. CSAPR's predecessor, CAIR, similarly looked to reduce airborne emissions in certain states that impacted the air quality of other states. CSAPR addresses pollution in 27 states and is applicable to generators larger than 25 MW (PJM 2011, Nelson 2011).

The new CSAPR rule was to take effect in 2014, requiring power plants to cut their sulfur dioxide emissions by 73 percent and their nitrogen emissions 54 percent from 2005 levels (EPA 2012a). Instead, a U.S. Court of Appeals overturned it, finding that through the rule the EPA "had exceeded its authority" in the manner in which it required states to reduce their emissions (Wald 2012). Though the CSAPR rule will not take effect as planned, it is generally expected that some similar rule will replace the now-in-effect old CAIR rule within the next five years.

The aim of the MATS rule is to limit emissions of mercury, arsenic, and other toxic pollutants from coal- and oil-fueled power plants in every state. The rules also apply to generators 25 MW or larger, and will generally require the installation of new pollution control equipment at affected generators. Plants are given up to four years to comply with the new emissions limits. Nationwide there are about 600 power plants affected by the MATS rule, and the EPA values the health benefits of the MATS rule at $37 billion to $90 billion annually (EPA 2012b).

As the MATS rule and other future EPA rules begin to impact coal plants, utilities will be faced with difficult investment decisions. There is evidence that the above-mentioned economic issues and the anticipation of regulatory requirements are already impacting markets for future electric generating capacity (PJM 2011). Beyond the EPA, state-level emissions goals such as those codified in California's Assembly Bill 32 will continue to put pressure on electric generating units to produce cleaner electricity.

Coal-powered electric generating units have options to meet the new limits on emissions. As the next section will describe, the choice of whether to retire a unit or invest in pollution controls will depend heavily on the economic situation each individual plant finds itself in. What is certain is that the above-described economic conditions and regulatory changes are causing significant changes in the way the U.S. generates electricity.

The Future of Coal

Many different stakeholders have attempted to ascertain the overall impact of the changing economic and regulatory environment on coal generation. This section will describe some of the issues considered when making such assessments, and describe some of the different estimates of overall impacts on coal-powered electric generation assets.

COST OF COMPLIANCE

For plants impacted by regulations, the first consideration for any owner is assessing the cost of compliance. Owners of such units will consider retrofitting older units to reduce overall emissions, and must determine whether making such pollution control investments is cost-effective.

There is a variety of pollution control equipment available to help control some of the regulated pollutants. Some of the available options come in a wide range of costs:

- To control SO_2, plants can implement flue gas desulfurization at an estimated cost of \$802/kW;
- To control NO_x, plants can implement selective catalytic reduction at an estimated cost of \$369/kW;
- To control mercury, plants can install a fabric filter and implement activated carbon injection at an estimated cost of \$172/kW; and
- To control SO_2, plants can implement dry sorbent injection at an estimated cost of \$118/kW (PJM 2011).

Each pollution control option has different benefits and drawbacks. Ones with lower up-front costs often have higher operation and maintenance costs, and vice-versa. Some plants have some pollution controls in place, but will need to make investments in additional controls to meet the newer rules and standards.

While many of the plants that will implement pollution controls have not yet, some of the anticipation of making investments in pollution controls has already been reflected in the market. One analysis of the rising costs of coal capacity in the PJM base residual auction for the 2014/2015 delivery year found that the anticipated costs of pollution control retrofits were responsible for 61–81 percent of the increase in future coal capacity prices. This price increase was likely responsible for the fact that the most recent auction saw a reduction of 16 percent in coal capacity from the prior auction year (PJM 2011).

COMPLY OR REPLACE DECISIONS

Utilities and other owners of coal-powered electric generation assets are currently considering the costs of compliance with new and future regulations, and the economic factors facing their generators now and in the future. While there are continued revenues to be enjoyed by maintaining operation of existing assets, there are also costs that may not be justified by the benefits. Utilities and others may also determine that the costs to continue operation of their less economic assets might be better spent on new, cleaner assets.

In general the cost of environmental compliance will be compared to the cost of new gas-fired generation resources. Larger units (over 400 MW) are more likely to decide to invest in pollution control, while smaller ones will likely find that the economics of installing pollution control are unattractive compared with retirement and the development of new gas-fired systems (PJM 2011). The older units, especially those over 40 years old, have likely not invested in plant modernization and will thus be ill-equipped to meet new economic and regulatory challenges (PJM 2011).

The reasoning behind these decisions is complicated, and involves substantial cost-benefit analyses by utilities in determining whether investments made in coal-fired power today will be worth enough in the future to warrant such an investment. The method by which affected plant owners will determine whether or not to invest in modernization and pollution control or retire the plant and reinvest in new generation resources will vary depending on the owner's assessment of and appetite for risk.

With the overturned CSAPR, coal generation asset owners in states affected by cross-state pollution regulations are left without a clear idea as to what some of the future regulations will look yet. Regardless, many such owners need to make decisions now to respond to pressing economic concerns. For some, investments in natural gas and other less-polluting resources in the near term could help hedge against unknown future regulations.

Coal-powered units, then, will likely continue to appear less economic as cleaner, more efficient options are considered. At present, utilities are increasingly finding it more economically beneficial to retire coal-fired generating units and replace them with new, natural gas fired units rather than invest in pollution controls. An assessment by the Edison Electric Institute determined 22 GW of coal-powered generation would be retired by 2015 absent any new EPA regulations[1] (Tierney and Chicchetti 2011). Indeed, it seems coal has already been losing favor as a result of its overall economics for years: over the past decade, 81 percent of new capacity additions to the U.S. electricity generation fleet were natural gas-based (EIA 2011b).

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[1] EEI's estimate does, however, consider the impact of the CAIR rule, which CSAPR would have replaced.

While we know that some coal plants will retire, and that cleaner and more modernized plants will replace many of those retired plants, it is impossible to perfectly predict the future. Economic and regulatory unknowns leave many coal plant owners with difficult decisions to make in the very near future.

RETIREMENT ESTIMATES

Utilities have begun retiring coal plants, and more are expected through the next decade. Some plant closure specifics or plans for replacement generation have not been developed or published, making it impossible to determine the exact amount of future capacity loss. However, a number of sources have attempted to aggregate the announced and planned retirement list, providing a good sense of how many GW of closures are expected through between now and 2020.[2]

Overall, projected retirements range from 2–5 percent of total U.S. generating capacity. The current nationwide electric generating capacity is 1,139 GW, and the portion served by coal is 342 GW (EIA 2011a). A recent study from the Bipartisan Policy Center and another from the EIA put the range of total near-term national retirements at 29-35 GW and 19-45 GW respectively (Macedonia and Kelly 2012). For the reference case in its 2012 *Annual Energy Outlook,* the EIA estimated 49 GW of coal retirement through 2020 (EIA 2012). Most of the retirements are expected in the very near term -- by 2015 (PJM 2011).

While estimates vary widely, it is generally accepted that states heavily dependent on coal will see some coal retirements in the near future. Only particular regions are expected to see significant retirements, primarily the areas covered by the Midwest Independent System Operating (MISO); the Electric Reliability Council of Texas (ERCOT); and the PJM Interconnection, which covers the majority of Pennsylvania, New Jersey, Delaware, Ohio, West Virginia, Maryland, Virginia, and the District of Columbia (Celebi et al. 2010).

Table 1 shows the likely retirements in the 12 target states this report identified as having substantial likely coal retirements, substantial CHP potential, or both. This table reflects a multitude of studies and resources estimating coal retirements, but generally reflects retirement estimates for the near term: coal expected to be retired by 2020 or earlier. As noted above, only some states will be heavily impacted by the changing economics of coal and the new environmental regulations. We find Indiana, Iowa, Kentucky, North Carolina, Ohio, and West Virginia to be the states likely to see the largest percentage of their overall operating capacity retired in the near term.

Most of the published national studies on coal retirements assume the implementation of both CSAPR and the MATS rules. While CSAPR has been overturned for now, a replacement rule will be developed. Furthermore, the impact of MATS on coal retirements is generally viewed as far more substantial than that of CSAPR (FBR 2010). All estimates consider the overarching economic

[2] In addition to the retirement estimates listed here, Cleetus 2012 offers an exhaustive list of other coal retirement estimates from a host of different organizations.

challenges faced by coal regardless of regulatory activity, though they vary in their market assumptions.

Table 1: Likely Range of Coal-Powered Electric Generation Retirements for 12 States

State	Total Installed Capacity (MW)	Total Installed Coal Capacity (MW)	Estimated Retirements (MW)	State's Capacity from Coal (%)	Overall Capacity Likely Retiring (%)	Coal Capacity Likely Retiring (%)
AL	32,417	11,441	678-2,948	35.3	2.1-9.1	5.9-25.8
CO	13,777	5,702	532-996	41.4	3.9-7.2	9.3-17.5
GA	36,636	13,230	842-2,059	36.1	2.3-5.6	6.4-15.6
IN	27,638	19,096	1,957-2,966	69.1	7.1-10.7	10.3-15.5
IA	14,592	6,956	420-1,757	47.7	2.9-12.0	6.0-25.3
KS	12,543	5,179	0-92	41.3	0.0-0.7	0-1.8
KY	20,453	14,566	1,996-2,928	71.2	9.8-14.3	13.7-20.1
LA	26,744	3,417	N/A	12.8	N/A	N/A
NC	27,674	12,766	2,345-2,373	46.1	8.5-8.6	18.4-18.6
OH	33,071	21,360	2,228-4,498	64.6	6.7-13.6	10.4-21.1
SC	23,982	7,230	391-900	30.1	1.7-3.8	5.4-12.4
WV	16,495	14,713	1,707-1,842	89.2	10.3-11.2	11.6-12.5

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d, IUB 2011

In addition to the above estimates, some other useful national data points include:

- The EIA reported earlier this year that utilities have announced they expect to see 27 GW of coal capacity retired between 2012 and 2016 (EIA 2012b).
- SourceWatch's tally of announcements and planned (including probable) retirements puts the total at just under 29 GW through 2025 (SourceWatch 2012).
- SNL Financial finds just over 30 GW of likely retirements by 2021 (SNL 2011).
- FBR Capital Markets estimated 45 GW of retirements through 2020 (FBR 2010).

Financial research firms such as Moody's anticipate that most of the lost coal capacity and the switch to natural gas will be permanent (Parker 2012). Looking out to 2035, the EIA notes in its *2012 Annual Energy Outlook,* coal will "never again [reach] the 2010 share of 45 percent (of U.S. electric generation capacity)" in any of the EIA's various economic scenarios (EIA 2012).

The Efficiency Opportunity

Utilities and owners of coal-powered generation assets will make significant investments in energy assets in the next few years. For some, those investments will be pollution controls at existing plants.

For others, the investments will be new generation assets entirely. There is a third option that could meet consumer demand at a cost far lower than pollution controls or new generation: energy efficiency.

Energy efficiency has consistently proven to be a least-cost resource for utilities and system planners around the country (Friedrich et al. 2009, Lazard 2011). It is a clean and quickly deployable energy resource that keeps costs down for consumers and produces ancillary benefits such as substantial job creation (Elliott et al. 2011, Chittum et al. 2012). Indeed, the largest regional transmission operator facing substantial coal retirements believes energy efficiency could help meet future resource needs at a cost lower than even the existing generating fleet (PJM 2011).

Estimates of the overall level of investment to be spent on updating or replacing affected coal plants range from \$70-\$180 billion (Celebi et al. 2010, FBR 2010). Utilities will bear a large share of the costs, but they will, like with other investments, share the burden with their customers through new rates that reflect that increased levels of investment. Such a substantial amount of money spent on new energy assets would be most prudently spent on energy efficiency.

The EPA itself has recognized the importance of energy efficiency by indicating in final and draft rules that they view energy efficiency as an appropriate compliance mechanism to help certain affected sites meet regulatory requirements (Dietsch et al. 2012). The EPA finds energy efficiency to be a critical component in lowering overall compliance costs, keeping bills low and helping customers better control energy costs, and “delaying or avoiding” new investments in generation and pollution controls (Dietsch et al. 2012).

Most states have the mechanisms in place to spread the costs of investments in energy efficiency among ratepayers via various cost-recovery mechanisms. A recent study found 44 U.S. states have some type of cost-recovery mechanism in place to help support energy efficiency programming (Chittum and Nowak 2012, Kushler et al. 2012). Ratepayers in these states can enjoy lower electric rates and cleaner air, all at a fraction of the cost of new generation.

However, utilities and other organizations that invest in energy efficiency could invest substantially more. Cost-recovery mechanisms alone do not always incentivize substantial investments in energy efficiency, because utilities in many states can still earn a greater rate of return on investments in traditional assets such as new electric generation. Shareholder incentives and other mechanisms that are linked to the meeting of energy efficiency goals are one way utilities around the country are being encouraged to increase their energy efficiency investments (Hayes et al. 2011).

As utilities continue to report that EPA regulations will cause substantial hikes in customer rates, it is imperative to emphasize that responding to new economic conditions and regulations does not necessarily have to come at the expense of consumer’s pocketbooks. Energy efficiency is regularly shown to be one-tenth to one-third the cost of investments in both fossil-fuel and renewable-based electricity generation (Friedrich et al. 2009).

Indeed, American Electric Power (AEP) recently scrapped plans to retrofit one if its largest coal plants in Kentucky, after environmental and consumer groups balked at the proposed \$940 million investment in pollution controls on an older 800 MW coal-fired plant. AEP had asked for a 30 percent rate increase to fund the new pollution controls at the plant, but now appears to be considering full retirement (Lipton 2012).

Such rate increases are not necessary. Kentucky utilities as a whole only budgeted $27.1 million for energy efficiency in 2010 (ACEEE 2012b). Utilities in that state, including AEP, could spend more on energy efficiency to help cost-effectively meet the demand previously met by the retiring plant. Such investments would not require a 30 percent rate increase. Most cost-recovery mechanisms that fund substantial energy efficiency programming are 2–5 percent adders on existing electricity bills (Chittum 2011).

Energy efficiency of all kinds can quickly and cost-effectively meet the electricity demand of areas that are planning for retirements of existing coal plants. Certain energy efficiency investments, though, are particularly well suited to the industrial facilities in the regions most affected by the changing coal economics and regulatory environments. Combined heat and power (CHP) is one of these types of energy efficiency investments that, though decades old, is only now just beginning to receive mainstream support from policymakers and other stakeholders.

Combined Heat and Power

Combined heat and power (CHP) is a suite of technologies that can simultaneously generate electric and thermal energy. The concurrent generation of both types of energy confers substantial efficiency benefits, and CHP typically operates at a combined electric generation and thermal efficiency of 65–80 percent, comparing favorably to the average efficiency of grid-providing electricity, which is about 33 percent (EPA 2012c).

CHP can be deployed far faster than more traditional generation, and its high levels of efficiency, as well as reduced transmissions and distribution losses, mean each unit of fuel yields more useful usable energy. CHP is cheaper than most forms of electricity generation. The levelized cost of a new 20 MW natural gas-powered combined cycle CHP system is about 6.0 cents/kWh, while a new natural gas-powered combined cycle system without CHP ranges from 6.9-9.7 cents/kWh. Nuclear generation is estimated at 7.7-11.3 cents/kWh (Lazard 2011, IDEA 2011).

CHP's cost-effectiveness is more favorable when considering its impact on emissions. Energy efficiency and CHP are the best options available to states today considering how to cost-effectively cut emissions. CHP reduces the need to generate separate thermal energy onsite, which would typically be supplied by a gas, coal, or oil-fueled boiler. As a result, CHP systems cost, per useful BTU of energy, substantially less than any other generation resource. CHP systems then require the burning of far fewer BTUs of fossil fuel to generate the same amount of energy as separate generation of electric and thermal power—greatly reducing the overall emissions generated to meet demand (IDEA 2011). Energy Efficiency, including CHP, effectively squeezes more bang out of every BTU generated.

CHP can be installed at hospitals, universities, manufacturing facilities, multifamily housing structures, commercial buildings and a wide range of other facilities. The various technologies that make up CHP systems can run on natural gas, biomass, biogas, and other fossil and renewable fuels, accommodating local fuel opportunities. CHP systems cost-effectively and cleanly meet electric and thermal needs of a wide range of facilities in every state in the U.S.

Despite CHP's many benefits, it still only accounts for about 8.6 percent of U.S. electric generating capacity (Shipley et al. 2008). In 2011, the U.S. only saw the installation of 569 MW of new CHP capacity (ICF 2012). The second column of Table 2, below, details the amount of CHP currently installed in the 12 target states.

CHP is most efficiently sized when the CHP system's thermal output is matched to the base load thermal demand at a site. At facilities with extensive thermal loads, an appropriately sized CHP system will likely generate more electricity than can be used on site. In this case, the system would have excess electricity to export to the grid. However, in most states, that excess electricity can only be sold at low wholesale rates, if it can be sold at all.

When considering the export opportunity for CHP, the remaining technical potential for CHP in high load sectors[3] is very high. The third column of Table 2, below, details the estimated technical potential for CHP remaining in each of the 12 target states. In just these 12 states, a total of about 57.6 GW in CHP technical potential remains. This estimate includes the following components:

- Existing business facilities that could install a high load factor[4] CHP system and use all of the power generated on-site;
- The incremental potential at these existing sites that could support remaining on-site thermal loads with power export to the grid; and
- Conservative estimates of growth in potential over the forecast period for both the onsite and incremental export markets—with a range of 0.8 to 1.3 in annual growth factors.

The technical potential for the 12 states is well above even the high range scenario estimates of likely *nationwide* coal retirements, but taking advantage of that technical potential could be a challenge. Some areas of the country have seen healthy growth in their CHP markets, but CHP faces a number of economic and regulatory hurdles. In some cases very cheap electricity or more expensive CHP fuel make certain CHP applications harder to justify. CHP also suffers from a lack of policies explicitly designed to encourage new installations. CHP is often not even considered by utilities and appropriate facilities because it is not a widely understood suite of technologies.

The calculated technical potential is based only on the physical characteristics of the facilities analyzed—and does not consider individual project economics. To understand what the potential is for CHP given current economic factors and constraints, an economic potential must be derived. The fourth and fifth column of Table 2 detail the economic potential for CHP in two scenarios: a base

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[3] "High load factor" sectors include all major manufacturing and industrial sectors, and some energy-intensive commercial and institutional sectors such as hotels and colleges/universities. See Appendix A for more detail.

[4] A system with a high load factor is one that has an average energy load that is not too different from its maximum (peak) load over time—meaning the system is run steadily at a high percentage of its overall capacity, which maximizes efficiency.

case, which reflects significant risk aversion typical of an industrial firm; and a utility case, which assumes a much higher acceptance of longer payback periods, to reflect the typical investment decisions made by utilities. Appendices B and C detail the various assumptions made in each case. Table 2 reflects potential only through 2020, to better compliment the fact that most of the likely coal retirements will occur before 2020.

As can be seen in Table 2, there is a wide range of both installed CHP capacity and the potential for new CHP capacity in the 12 states. Electricity prices, natural gas prices, industrial intensity, and the policy and regulatory environments of each state all have influenced historic CHP markets and will influence future ones.

Table 2: Technical and Economic Potential for Combined Heat and Power, 2011–2020

State	Current Installed Capacity (MW)	Total Remaining Technical Potential (MW)	Economic Potential, Base Case (MW)	Economic Potential, Utility Case (MW)
AL	3,303	5,029	137	1,501
CO	680	1,771	34	192
GA	1,214	7,767	79	833
IN	2,262	3,553	56	611
IA	590	3,112	3	39
KS	134	2,942	55	193
KY	123	5,553	20	245
LA	6,890	5,327	264	1,485
NC	1,530	6,223	151	1,338
OH	521	9,241	74	712
SC	1,186	5,391	352	1,946
WV	382	1,689	71	588

Source: ICF 2012, See Appendix A and B

The CHP market varies significantly from state to state, but some are more promising than others. For instance, about 60 percent of the new CHP capacity installed in 2011 was in Texas, Louisiana, New York, and California (ICF 2012). Ohio, Massachusetts, and other states have begun to prioritize CHP as a clean and cost-effective energy resource. But most states could do much more to encourage CHP, including finding ways to better involve utilities as partners in CHP projects. As shown in Table 2, involvement by utilities is critical to reaching the higher range of CHP's economic potential.

An Executive Order signed by President Obama in September 2012 set an official goal for U.S. CHP capacity for the first time in the nation's history. As a result of the order, federal agencies and their state counterparts are to work collaboratively to establish policies that help meet an aggressive goal of

40 new GW of installed CHP by 2020, on top of the 82 GW installed today (White House 2012). To help meet this goal, utilities will need to, for the first time in history, view CHP projects as essential assets in their efforts to cost-effectively supply clean energy for their customers and reliable returns for their investors.

The Role of Utilities

Utilities are uniquely positioned to invest in CHP, and their investment in CHP technologies will be critical to the meeting of the new national CHP goal. While an average industrial or commercial facility may find an investment with a five-year payback period to be unattractive, utilities are very used to making such investments. Their appetite for longer investment horizons is well-established and embraced by shareholders.

To help cost-effectively replace some of the lost coal capacity with CHP, utilities must be partners in making and encouraging new CHP investments. Smart investments by utilities in CHP could help keep rates down for customers and dramatically reduce emissions for everyone. Table 3 shows the percentage of coal retirements that could economically be replaced with CHP if utilities were to become major investors in new CHP projects. These percentages assume the *highest* projected amount of coal retirement in each of the 12 target states as well as the "utility case" economic potential as described above. As can be seen in Table 3, most of the states targeted for this report could meet a substantial amount of their lost capacity with cost-effective CHP, provided utilities were encouraged to make some of the investments.

While the establishment of a national goal is a significant step in encouraging substantially increased CHP deployment, there is still much policy work to be done. At present, most electric utilities still see CHP as antithetical to their business model. Greater investments in CHP will yield a reduced consumption of utility-provided electricity. Electric utilities are therefore hard pressed to put much effort toward encouraging their customers to install CHP. Shareholders of investor-owned utilities would rightly balk at such an effort, absent other possible revenue streams.

The good news is that other revenue streams do exist and can be expanded. With concerns about retiring coal plants and the ultimate price paid by consumers for pollution controls or replacement generation, now is an opportune time for utilities to aggressively invest in CHP. For utilities concerned about new and future emissions regulations, CHP offers a hedge against the unknown. Some states, such as Massachusetts, have recognized this and have developed portfolio standards and utility incentive mechanisms that appropriately value the benefits of energy efficiency and CHP. But these efforts are few and far between, and most states facing substantial coal retirements do not have such policies in place.

Table 3: Estimated Percentage of Retiring Coal Capacity That Could Be Replaced With New Combined Heat and Power (CHP) Systems, 2011–2020

State	Percentage Lost Coal Capacity Potentially Replaced with CHP
Alabama	51%
Colorado	19%
Georgia	40%
Indiana	21%
Iowa	2%
Kansas	100%
Kentucky	8%
Louisiana	N/A
North Carolina	56%
Ohio	16%
South Carolina	100%
West Virginia	32%

Sources: ICF 2012, FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d, See Appendix A and B

There are several ways policy makers could encourage utilities to invest in CHP. These include:

1. Giving utilities assurance that investments in CHP will return financial returns similar to or better than investments in other generation and distribution assets;
2. Allowing utilities to integrate CHP-focused programming into their suite of energy efficiency programming, and fund such programs out of collected ratepayer cost-recovery mechanisms and/or energy efficiency fees;
3. Treating CHP as a priority resource (Tier 1) as part of an established energy efficiency resource standard or other portfolio standard, or establishing a specific portfolio goal for CHP; and
4. Giving utilities better regulatory certainty at the state and federal level so that investments in CHP can be accurately and adequately valued for their ancillary benefits, such as transmission and distribution loss reduction and emissions reductions.

Utility regulations in the United States are not structured in a manner that allows utilities to view investments in CHP as a profit-making enterprise. By addressing this disconnect, the U.S. could move rapidly toward the new goal of 40 GW set by President Obama and help move the electric generation industry toward a cleaner and more prosperous future.

State-by-State Findings: Coal Retirements and the CHP Opportunity

To determine whether CHP could realistically replace some of the lost capacity due to retiring coal plants, we analyzed likely coal retirements and the potential for new CHP in 12 U.S. states. The states are:

- Alabama
- Colorado
- Georgia
- Indiana
- Iowa
- Kansas
- Kentucky
- Louisiana
- North Carolina
- Ohio
- South Carolina
- West Virginia

The remainder of the report presents 12 individual state profiles that summarize these findings and describe some of the policy and economic considerations in each state that might impact future CHP development. Though electricity is typically sold across state lines, and in-state generation is not necessarily consumed only in-state, we examine the in-state generation from coal as a proxy for a state's reliance on coal. We also examine coal retirements and CHP potential on the state level because CHP markets are heavily influenced by state-level policies. Further, utility-focused policies that might help incentivize utilities to invest in CHP are largely developed at the state level.

Ultimately we find that while CHP will not be able to economically replace all of the immediate lost capacity due to coal retirements, it can replace a significant amount. The potential for CHP is much higher in the economic case that considers substantial investment by utilities, which have longer investment timelines and can generally entertain investments with longer payback periods than individual industrial or commercial facilities. This finding is significant, because utilities are not presently incentivized to invest in CHP, so meeting the "high case" economic potential in each state will require substantial policy changes.

Each profile also describe the state's performance in the CHP chapter of the 2012 ACEEE *State Energy Efficiency Scorecard*, which ranks all states on multiple categories of energy efficiency policy, including CHP (ACEEE 2012a). The profiles highlight existing and possible new regulations or policies that would explicitly help utilities justify substantially increased investment in customer-sited CHP systems. We find that, among the 12 target states, most lack significant policies that would help increase the state's level of CHP deployment.

How These States Were Chosen

The 12 target states were chosen primarily for their substantial reliance on coal-fired electric generating capacity. Others, especially Louisiana, were chosen for their substantial CHP potential. We also prioritized states where stakeholders appear open to supporting and adopting policies that would help encourage greater CHP deployment.

State Analysis Methodologies

Retirement Estimates

The major sources of plant-by-plant and state-level estimates included SourceWatch, a project of the Center for Media and Democracy; SNL Financial, a financial information and research company; and FBR & Company, an investment bank. Additional resources include reports issued by regional transmission organizations such as PJM; announcements by utilities and public service commission; and reports and papers published by the Bipartisan Policy Center, Sierra Club, Union of Concerns Scientists, EPA, U.S. Congressional Research Service, and the EIA.

The multiple retirement estimates vary in their assumptions, and we thus present a range of retirement estimates for each state, in order to give readers a general sense of the expected scale of retirements in each state through 2020. It is impossible to predict with total accuracy the investment decisions each utility will make in the coming years, but it is possible to render a general idea of which states will be most affected by future coal retirements.

As noted earlier, most estimates assumed both the MATS and CSAPR rules would be in effect. While CSAPR was overturned, it is anticipated that EPA will develop a replacement rule over the next few years. CSAPR's predecessor, CAIR, is already integrated into most of the estimates' base cases.

Technical Potential

The technical potential is the potential for CHP in each state, considering only technological constraints. Economic factors do not enter into the analysis of technical potential. Each state was assessed for its current industrial, commercial, and institutional building demographics. Facilities were further identified as belonging to particular NAICS classifications,[5] which were then ascertained for their fitness for CHP based on energy load characteristics. Those with low load factors were excluded, as noted in Appendix A, because facilities with higher load factors and high heating requirements are generally better suited to CHP applications. CHP is typically sized according to thermal loads, and then the electricity output of a CHP system is used to satisfy part or all of a facility's base load electricity needs.

The technical potential is based on facilities in each of the target states with over 1 MW of potential, including export capacity. For additional information, Appendix A offers a full detailed description of the assumptions underpinning the analysis of each target state's technical potential for CHP.

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[5] NAICS is the North American Industrial Classification System. More information can be found here: http://www.census.gov/eos/www/naics/.

Economic Potential

The economic potential is the potential for CHP considering economic factors such as local electricity prices, prices of wholesale electricity (that a CHP system could sell back to the grid), prices of natural gas, and costs of equipment. It also considers the investment behavior of facilities and the performance of different types of technology. The economic potential is a subset of the technical potential: not all of the technical potential can be installed, due to economic constraints. The economic potential is an attempt to determine the amount of CHP that might actually be installed given certain economic conditions and financial decision-making parameters.

The economic potential for this analysis looks only at the short-term potential, through 2020. This is due to a desire to more closely mirror the retirement activity of coal plants, which is expected to occur mostly in the next five years. It also looks at both the potential for onsite generation and for additional incremental power export to the grid.

Base Case

The base case economic potential includes an assumption of a high degree of risk-aversion by facilities considering new CHP projects. This is in keeping with recent behaviors seen in the industrial and commercial sectors immediately following the recent recession. The base case assumes only a 50 percent acceptance of CHP systems with a two-year payback period. This assumption mirrors a market acceptance curve informed by a 2003 market survey of customer perceptions of technical risk (See Appendix B). It also reflects conversations with industrial decision-makers who report that a two year simple payback period is the longest payback period they are willing to accept for major capital projects given current economic conditions. While it is generally understood that CHP systems are more capital-intensive than typical energy efficiency projects, the base case nevertheless remains conservative in its estimates to reflect firms still feeling significant aversion to risk.

High "Utility" Case

The high case is also called the utility case, because it assumes substantial investment in CHP by utilities themselves. Utilities can often take much longer views of capital expenditures than a typical industrial facility, and are uniquely positioned to invest in CHP in place of other types of energy assets. Utilities are able to spread the cost of major investments over many years and many ratepayers. This type of cost-sharing is similar to energy efficiency programming, which is often funded by small contributions from every system user. The costs of investments in CHP could be aggregated like other investments and then borne by each system user through increased rates or energy efficiency fees. Each system user would pay for the asset through rates, but enjoy the overall reduced cost of energy and emissions compared to other forms of electricity generation.

The utility case thus shows a "what if" potential, and assumes a bigger appetite for long payback periods, in keeping with typical utility investment behaviors. It assumes a 100 percent acceptance of CHP systems with five-year payback periods, and a 50 percent acceptance of systems with ten-year payback periods. While such market acceptance is not likely today given current utility regulatory structures, it is economically possible given the long term economic benefits of CHP systems.

Additional details of all the assumptions made in the economic cases can be found in Appendix B.

ALABAMA

The bottom line: Alabama could meet 51 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 4, just over one third of Alabama's in-state electric generating capacity is coal-based, and Alabama may see up to a quarter of it retired in the near term, though estimates vary widely. Alabama has one of the largest nuclear power plants in the country and is a substantial exporter of coal. The state is one of the top ten emitters of CO_2, and sees fairly average retail electricity prices (EIA 2012d).

Table 4: Alabama Likely Range of Coal-Powered Electric Generation Retirements (MW)

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
32,417	11,441	678-2,948	35.3%	2.1-9.1%	5.9-25.8%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

Alabama has just over 5 GW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the chemicals and paper industries. Table 5 illustrates the total technical potential for CHP in Alabama today.

Table 5: Alabama Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	4,254	581	4,835
Commercial/Institutional	171	23	194
Total	4,424	604	5,029

Sources: See Appendix A

Of the state's 5 GW of technical potential, only about 137 MW is viewed as economic in the base case, the majority of it in the industrial sector. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 1,501 MW of new CHP installations. Table 6 illustrates the two economic cases for CHP in Alabama.

Table 6: Alabama Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			3,303
Remaining Technical Potential	1,258	3,771	5,029
Base Case Market Penetration 2012-2020	34	103	137
Utility Ownership Case Market Penetration 2012-2020	175	1,326	1,501
Output, million kWh/year			
Base Case Market Penetration 2012-2020	275	832	1,107
Utility Ownership Case Market Penetration 2012-2020	1,411	10,686	12,097
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	313	965	1,278
Utility Ownership Case Market Penetration 2012-2020	1,599	12,265	13,863

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 7, Alabama earned 0.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. The state has seen only one new small CHP installation in the past five years: a 25 kW biomass-fueled installation at a Hartford farm. The CHP environment in the state has remained stagnant, in part due to low electricity prices and a lack of interest in CHP by the state's utilities.

Alabama also lacks basic policies to support distributed generation. Alabama does not have an interconnection standard in place, leaving CHP developers with no clear, delineated path toward interconnection to the grid. It also does not offer a net metering standard for distributed generation, and lacks any type of efficiency or renewable portfolio standard that might help hasten CHP. Utilities can recover costs of energy efficiency programs through rate riders, and Alabama Power does this in its limited commercial and industrial energy efficiency offerings.

Table 7: Alabama CHP Policy and Regulatory Environment

Alabama	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

CHP Installs 2007-2011	1
kW CHP Installed 2007-2011	25
2012 Scorecard Score - CHP	0.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Though Alabama does not offer incentives explicitly for CHP, the ARRA-supported Alabama Saves program, administered by the Alabama Department of Economic and Community Affairs, does offer loans for industrial energy efficiency projects. These loans are attractive for their 2 percent interest rates and their ceiling of $4 million. The loans can be used for a variety of efficiency projects, including CHP. Though no CHP installations have yet been supported by the program, several CHP feasibility studies are currently being conducted (Smith 2012). Alabama was also one of four states selected to participate in an upcoming National Governors Association's policy academy, designed to help and encourage states to develop industrial energy efficiency and CHP-focused action plans (NGA 2012).

COLORADO

The bottom line: Colorado could meet 19 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 8, about 40 percent of Colorado's in-state electric generating capacity is coal-based. The state will likely see over ten percent of it retire, including the likely impacts from the 2010 Clean Air—Clean Jobs bill.[6] Colorado has a fairly aggressive renewable portfolio standard, and is currently a substantial producer of solar power. The state has slightly above average emission rates and its residents see fairly average retail electricity prices (EIA 2012d).

[6] See http://www.bizjournals.com/denver/news/2012/09/11/epa-approves-clean-airclean-jobs-act.html?page=all for a recent update on the Clean Air—Clean Jobs bill.

Table 8: Colorado Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
13,777	5,702	532-996	41.4%	3.9-7.2%	9.3-17.5%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

Colorado has 1,771 MW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with much of the potential in the petroleum refining and food industries. Table 9 illustrates the total technical potential for CHP in Colorado today.

Table 9: Colorado Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	1,307	180	1,488
Commercial/Institutional	249	34	284
Total	1,556	215	1,771

Sources: See Appendix A

Of the state's 1,771 MW of technical potential, only about 34 MW is viewed as economic in the base case, two thirds of it in the industrial sector. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 192 MW of new CHP installations—again, about two thirds of it in the industrial sector. Table 10 illustrates the two economic cases for CHP in Colorado.

Table 10: Colorado Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			680
Remaining Technical Potential	777	995	1,771
Base Case Market Penetration 2012-2020	34	0	34
Utility Ownership Case Market Penetration 2012-2020	192	0	192
Output, million kWh/year			
Base Case Market Penetration 2012-2020	264	0	264
Utility Ownership Case Market Penetration 2012-2020	1,474	0	1,474
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	321	0	321
Utility Ownership Case Market Penetration 2012-2020	1,767	0	1,767

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 11, Colorado earned two out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. The state has had a fair amount of new CHP installations in the past five years. The state has consistently scored in the middle of the road on CHP policies, but there remains substantial room for improvement.

CHP is not explicitly encouraged by Colorado policies, though "recycled energy" is. In effect, this means that new CHP projects might not always qualify for incentives and certain policies may not be applicable. For instance, waste heat–powered "bottoming cycle" CHP qualifies for the state's renewable portfolio standard and net metering standard, but fossil fuel-powered "topping cycle" CHP does not.

Table 11: Colorado CHP Policy and Regulatory Environment

Colorado	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

Number CHP Installs 2007-2011	6
kW CHP Installed 2007-2011	9,490
2012 Scorecard Score - CHP	2/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Colorado does have an interconnection standard in place for systems up to 10 MW in size. It also offers financing assistance through a revolving loan program administered by the state's Energy Office (CEO 2012). The program is designed to provide financing for "eligible and extraordinary projects that promote energy efficiency or renewable energy," and is intended to benefit programs that would not otherwise be able to easily obtain funding from the private sector. Energy efficiency projects are eligible.

One way Colorado might see a greater number of CHP installations is by addressing the standby rates charged by Xcel Energy and other utilities. These rates are viewed as unnecessarily high and have been cited by developers as the reasons certain CHP projects were not carried through to completion. The Colorado Public Utilities Commission has taken interest in the subject, and in August 2012 opened an investigatory docket to research CHP standby rates (CPUC 2012). Utilities in Colorado are not currently incentivized to encourage CHP projects.

GEORGIA

The bottom line: Georgia could meet 40 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 12, just over one third of Georgia's in-state electric capacity is provided by coal. The estimated ranges of coal retirements to affect Georgia are wide ranging, but it appears that only a small amount of the state's generating capacity will probably retire. Georgia generates more electricity than all but three other states and is in the top ten states of CO_2 emitters. The state generates more electricity from nuclear resources than natural gas ones and its retail electricity prices are very average. It also has one of the highest amounts of biomass-based generation in the country (EIA 2012d).

Table 12: Georgia Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
36,636	13,230	842-2,059	36.1%	2.3-5.6%	6.4-15.6%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

Georgia has 7,767 MW of total technical potential for CHP, including export. The majority of this potential is in the industrial sector, with most of the potential in the paper, chemicals, textiles, petroleum refining, and food industries. Table 13 illustrates the total technical potential for CHP in Georgia today.

Table 13: Georgia Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	6,573	854	7,427
Commercial/Institutional	301	39	340
Total	6,874	893	7,767

Sources: See Appendix A

Of the state's over 7 GW of technical potential, only about 79 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 833 MW of new CHP installations. Table 14 illustrates the two economic cases for CHP in Georgia.

Table 14: Georgia Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			1,214
Remaining Technical Potential	2,648	5,119	7,767
Base Case Market Penetration 2012-2020	52	27	79
Utility Ownership Case Market Penetration 2012-2020	304	529	833
Output, million kWh/year			
Base Case Market Penetration 2012-2020	422	214	636
Utility Ownership Case Market Penetration 2012-2020	2,448	4,262	6,709
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	481	259	740
Utility Ownership Case Market Penetration 2012-2020	2,784	5,158	7,942

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 15, Georgia earned 0.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. The state has seen only two new CHP installations in the past five years, none of them in the previous two. The state has consistently scored very poorly on CHP policies, and has tremendous room to improve.

The state lacks all of the substantial policies that could encourage CHP, and offers only limited incentives. The Clean Energy Tax Credit can apply to CHP if it is part of a whole building efficiency upgrade, but the credit maximum is $100,000. The Biomass Tax Exemption applies only to CHP systems which use organic matter—rather than fossil fuels—as an energy source. Georgia currently has no interconnection standard, financing assistance, energy efficiency standard, output-based emissions regulations, or net metering policies that apply to CHP. Notably, the state chose not to adopt an interconnection standard in responding to the Energy Policy Act of 2005.

Utilities are not currently incentivized to invest in or support CHP. Standby rates charged by utilities are viewed as high, and Georgia Power, the only regulated utility in the state, is not required to meet any particular energy efficiency savings goals.

Table 15: Georgia CHP Policy and Regulatory Environment

Georgia		Key	
Interconnection Standards		Weak	
Financial Incentives		Medium	
Financing Assistance		Strong	
Output-Based Emissions Regulations			
CHP in RPS/Energy Efficiency Standards		Number CHP Installs 2007-2011	2
Net Metering		kW CHP Installed 2007-2011	4,000
Other Supportive Policies		2012 Scorecard Score - CHP	0.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

INDIANA

The bottom line: Indiana could meet 21 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 16, over two thirds of Indiana's in-state electric generating capacity is coal-based. Over ten percent of it will likely retire in the near term. Indiana ranks very high in pollution from electric generation, and has some of the lowest retail electricity prices in the country. It has a healthy ethanol industry and features the largest oil refinery beyond those in the Gulf Coast area (EIA 2012d).

Table 16: Indiana Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
27,638	19,096	1,957-2,966	69.1%	7.1-10.7%	10.3-15.5%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

Indiana has 3,553 MW of total technical potential for CHP, including export. The majority of this potential is in the industrial sector, with most of the potential in the paper, chemicals, and food industries. Table 17 illustrates the total technical potential for CHP in Indiana today.

Table 17: Indiana Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	2,829	448	3,277
Commercial/Institutional	238	38	276
Total	3,068	485	3,553

Sources: See Appendix A

Of the state's 3,553 MW of technical potential, only about 56 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 611 MW of new CHP installations. Table 18 illustrates the two economic cases for CHP in Indiana.

Table 18: Indiana Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			2,262
Remaining Technical Potential	1,619	1,934	3,553
Base Case Market Penetration 2012-2020	16	40	56
Utility Ownership Case Market Penetration 2012-2020	124	487	611
Output, million kWh/year			
Base Case Market Penetration 2012-2020	128	323	451
Utility Ownership Case Market Penetration 2012-2020	1,003	3,925	4,928
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	150	376	526
Utility Ownership Case Market Penetration 2012-2020	1,166	4,556	5,721

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 19, Indiana earned two out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. Indiana has seen four new CHP installations in the past five years, none of them in the previous two. All four installations are smaller in scale, and three of them are powered by biomass. The state has consistently scored in the middle on CHP policies, and has substantial room to improve.

Table 19: Indiana CHP Policy and Regulatory Environment

Indiana	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

Number CHP Installs 2007-2011	4
kW CHP Installed 2007-2011	420
2012 Scorecard Score - CHP	2/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Indiana has a mixed bag of CHP policies and regulations in place. On the positive side, CHP is explicitly eligible for Indiana's three-tiered interconnection standard with no size limit, but systems larger than 2 MW are subject to increased fees. Indiana's Clean Energy Portfolio Standard, enacted in 2011, includes CHP, but it is only a voluntary target of 10 percent clean energy by 2025. Indiana's State Implementation Plan for reducing NO_x levels allowed energy efficiency set-asides, to credit projects that reduce electricity consumption. CHP that is at least 40 percent efficient could be an eligible technology for the energy efficiency set-asides, with some technologies required to meet a 60 percent efficiency threshold. Credits for CHP systems are developed using output-based measures.

Indiana lacks a number of important programs that could encourage CHP. There is currently no state financing assistance, financial incentives, or net metering in place for CHP. Additionally, while utilities have not been regularly cited as obstacles to new CHP projects, they also have no economic incentive to encourage CHP projects at this time.

Iowa

The bottom line: Iowa could meet 2.2 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 20, almost one half of Iowa's in-state electric generating capacity is coal-based. Up to one quarter of that will be retiring. Iowa is the country's largest ethanol producer and wind is the state's second most-used source of energy, behind coal. Iowa has some of the lowest retail electricity rates in the nation (EIA 2012d).

Table 20: Iowa Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
14,592	6,956	420-1,757	47.7%	2.9-12%	6-25.3%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d, Baer 2012, IUB 2011

Combined Heat and Power Opportunity

Iowa has 3,112 MW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the paper, food, and chemicals industries. Table 21 illustrates the total technical potential for CHP in Iowa today.

Table 21: Iowa Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	2,617	390	3,007
Commercial/Institutional	92	14	105
Total	2,709	404	3,112

Sources: See Appendix A

Of the state's over 3 GW of technical potential, only about 3 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 39 MW of new CHP installations. Table 22 illustrates the two economic cases for CHP in Iowa.

Table 22: Iowa Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			590
Remaining Technical Potential	1,055	2,058	3,112
Base Case Market Penetration 2012-2020	3	0	3
Utility Ownership Case Market Penetration 2012-2020	39	0	39
Output, million kWh/year			
Base Case Market Penetration 2012-2020	27	0	27
Utility Ownership Case Market Penetration 2012-2020	311	0	311
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	41	0	41
Utility Ownership Case Market Penetration 2012-2020	479	0	479

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 23, Iowa earned 1.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. The state has seen few new CHP installations in recent years, and still has substantial room for improvement in its CHP-focused policies. In the past two years, Iowa has seen one new CHP installation: a 2.8 MW natural gas-powered system at the University of Iowa's Oakdale research campus. CHP activity has been minimal over the past decade, with developers citing basic economic considerations as a primary reason for the state's stagnant CHP market (Chittum and Kaufman 2011).

Table 23: Iowa CHP Policy and Regulatory Environment

Iowa
Interconnection Standards
Financial Incentives
Financing Assistance
Output-Based Emissions Regulations
CHP in RPS/Energy Efficiency Standards
Net Metering
Other Supportive Policies

Key
Weak
Medium
Strong

Number CHP Installs 2007-2011	4
kW CHP Installed 2007-2011	19,650
2012 Scorecard Score - CHP	2/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Iowa's electric utility situation is unique in that is has a substantial number of small municipal electric utilities and rural electric cooperatives. The state is home to 136 municipal utilities and 45 rural cooperatives, which collectively sell about 25 percent of the state's electricity. The remainder of the state is served by two investor-owned utilities (IUB 2012). The municipal and rural electric utilities are not rate-regulated by the Iowa Utilities Board (IUB), which has helped yield a patchwork of CHP policies, economics, and regulations around the state.

In general, Iowa offers minimal financial incentives to support CHP. The Iowa Renewable Energy Production Tax Credit applies only to CHP systems powered by renewables and only up to 5 MW. The Iowa Energy Bank does not list CHP explicitly as an eligible technology but offers public facilities a 1 percent financing option for cost-effective energy projects.

The regulatory patchwork is notable in the area of interconnection. Iowa's detailed interconnection standard applies to distributed generation facilities of up to 10 MW, and offers a tiered approach to expedite the interconnection of smaller systems. However, the standard applied only to systems within the service territories of the two regulated investor-owned utilities. Customers in the municipal and rural utilities' service areas are not offered an interconnection standard, leaving developers a less than clear environment in which to interconnect. Similarly, the state's effective net-metering policies only apply to customers of the state's investor-owned utilities, and only to renewable-powered systems up to 500 kW in size. Currently, Iowa has no output-based emission regulations.

A 2008 senate bill laid the groundwork for an IUB order requiring all regulated utilities to file energy savings plans to meet a 1.5 percent annual electricity and natural gas savings goal. Utilities that are not rate-regulated are required to develop plans to meet their own internally developed savings goals. Both of the investor-owned utilities filed plans to meet these goals through 2013. The IUB indicated that regulated utilities could include CHP in their energy efficiency plans, but neither MidAmerican nor Alliant currently offer any dedicated CHP programming as part of their energy savings efforts. Alliant's custom incentive program could include CHP in theory, but no CHP system has been supported or developed through Alliant's program (Baer 2012, Iowa SF 2008).

One issue that appears to deter new CHP deployments is the standby rates charged by both Alliant and MidAmerican. Both utilities use standby power rates that are unfavorable to CHP (Miller et al. 2012). Both rates featured high demand charges and demand ratchets, both of which can be detrimental to CHP economics.

While neither of the investor-owned utilities is actively pursuing CHP investments themselves, Alliant did attempt to include CHP in its initial 2008 energy efficiency plans, though it did not make it into the final plan. Alliant has also proven supportive of customer-sited renewable energy installations, and have a history of entering into long-term power-purchase agreements for distributed generation. Both utilities are set to file new energy efficiency plans in late 2012 and early 2013. Iowa was also one of four states selected to participate in an upcoming National Governors Association's policy academy, designed to help and encourage states to develop industrial energy efficiency and CHP-focused action plans (NGA 2012).

Additionally, Iowa's many ethanol plants present a unique opportunity for CHP. These plants are interested in meeting the low carbon fuel standards promulgated by states such as California,[7] and Iowa has recently developed a pilot incentive program to offer the above-mentioned production tax credit to natural gas-fueled CHP systems that serve ethanol plants wishing to meet low-carbon fuel standards (Iowa HF 2012).

KANSAS

The bottom line: Kansas could meet 100 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 24, over 40 percent of Kansas' in-state electric generating capacity is coal-based. Only a very small portion of that will likely retire. Some estimates even suggested that there are no imminent coal retirements on the horizon. Kansas has significant crude oil and natural gas resources in-state. Kansas residents and businesses enjoy lower than average retail electricity prices (EIA 2012d).

Table 24: Kansas Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
12,543	5,179	0-92	41.3%	0-0.7%	0-1.8%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

[7] See http://www.arb.ca.gov/fuels/lcfs/lcfs.htm for more information.

Combined Heat and Power Opportunity

Kansas has 2,942 MW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the petroleum refining and food industries. Table 25 illustrates the total technical potential for CHP in Kansas today.

Table 25: Kansas Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	2,551	277	2,828
Commercial/Institutional	103	11	114
Total	2,654	288	2,942

Sources: See Appendix A

Of the state's nearly 3 GW of technical potential, only about 55 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 193 MW of new CHP installations. Table 26 illustrates the two economic cases for CHP in Kansas.

Table 26: Kansas Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			134
Remaining Technical Potential	930	2,011	2,942
Base Case Market Penetration 2012-2020	55	0	55
Utility Ownership Case Market Penetration 2012-2020	193	0	193
Output, million kWh/year			
Base Case Market Penetration 2012-2020	444	0	444
Utility Ownership Case Market Penetration 2012-2020	1,552	0	1,552
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	644	0	644
Utility Ownership Case Market Penetration 2012-2020	2,232	0	2,232

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 27, Kansas earned one out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. Kansas has seen two new CHP installations in the past five years, none of them in the previous two. Both installations are 4 MW in size and are installed at ethanol plants. One project is a waste-recovery project and the other a natural gas-powered system. The state has consistently scored rather low on CHP policies, and has substantial room to improve.

Table 27: Kansas CHP Policy and Regulatory Environment

Kansas	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

Number CHP Installs 2007-2011	2
kW CHP Installed 2007-2011	8,000
2012 Scorecard Score - CHP	1/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Kansas offers an incentive and special financing terms for systems that generate electricity and recover waste heat. The Waste Heat Utilization System Incentive exempts CHP systems from all property taxes levied under the laws of the state for 10 years and a related authorization allows the Kansas Development Finance Authority to issue revenue bonds to aide in construction of the systems.

Kansas' interconnection standard includes only systems powered by renewable sources and only to systems with capacities up to 200 kW. Kansas allows net metering of systems up to 200 kW, but is also only applicable to systems powered by renewable fuels such as biomass. There are currently no output-based emissions regulations in place. Kansas does not include fossil fuel-powered CHP or waste heat recovery in its renewable portfolio and it does not have an energy efficiency standard in place.

Kansas has substantial natural gas reserves, and natural gas prices tend to be cheaper than average. With increased attention to CHP by utilities, Kansas could possibly take advantage of its own in-state gas reserves. At present Kansas utilities are not incentivized to pursue CHP projects and they are not required to offer any energy efficiency programs to customers.

KENTUCKY

The bottom line: Kentucky could meet eight percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 28, Kentucky relies substantially on coal, which represents over 70 percent of its in-state electric generating capacity. Up to one-fifth of that may retire, which would amount to about one-tenth of the state's total generation. Kentucky's reliance on coal is largely a product of the fact that it ranks third in coal production in the U.S. The state is one of the top ten emitters of several of the most widely regulated pollutants, and has some of the lowest retail electricity rates in the country (EIA 2012d).

Table 28: Kentucky Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
20,453	14,566	1,996-2,928	71.2%	9.8-14.3%	13.7-20.1%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

Kentucky has 5,553 MW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the petroleum refining, paper, chemicals, and food industries. Table 29 illustrates the total technical potential for CHP in Kentucky today.

Table 29: Kentucky Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	4,724	671	5,395
Commercial/Institutional	138	20	158
Total	4,863	690	5,553

Sources: See Appendix A

Of the state's 5,553 MW of technical potential, only about 20 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 245 MW of new CHP installations. Table 30 illustrates the two economic cases for CHP in Kentucky.

Table 30: Kentucky Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			123
Remaining Technical Potential	2,140	3,413	5,553
Base Case Market Penetration 2012-2020	20	0	20
Utility Ownership Case Market Penetration 2012-2020	245	0	245
Output, million kWh/year			
Base Case Market Penetration 2012-2020	164	0	164
Utility Ownership Case Market Penetration 2012-2020	1,976	0	1,976
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	221	0	221
Utility Ownership Case Market Penetration 2012-2020	2,648	0	2,648

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 31, Kentucky earned zero out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. Kansas has seen no new CHP installations in the past five years. The state has consistently scored very poorly on CHP policies, and has tremendous room for improvement.

Table 31: Kentucky CHP Policy and Regulatory Environment

Kentucky	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

Number CHP Installs 2007-2011	0
kW CHP Installed 2007-2011	0
2012 Scorecard Score - CHP	0.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Kentucky has very few policies and programs in place that support CHP. The state's interconnection standard and net metering rules apply only to systems powered by biomass or biogas and then only to those systems of 30 kW and smaller. There are currently no output-based emissions regulations in place and Kentucky does not have a renewable portfolio or energy efficiency standard.

Some incentive and loan programs can apply to CHP in Kentucky's public sector. Through the ARRA-supported Green Bank of Kentucky, state agencies may be eligible for three separate energy loan products, depending on the proposed energy efficiency improvements. Minimum loan size is $50,000, and CHP is eligible.

Utilities are not currently incentivized to pursue CHP, but a bill passed in 2010 allows the Kentucky Public Service Commission (KPSC) to require utility-administered energy efficiency programming (see ACEEE 2012b). The KPSC currently reviews and approves energy efficiency programming and related cost recovery surcharges. CHP programming is not currently a part of these efficiency programs.

LOUISIANA

The bottom line: Louisiana is not expecting any coal retirements, but its potential for new CHP capacity is substantial. They currently are not.

Coal Situation

As can be seen in Table 32, Louisiana's primary energy source is natural gas. Its in-state electric generating capacity is not substantially coal-based. Coal only represents a little over one tenth of the state's capacity, and none of that capacity is expected to retire. Louisiana has the second-largest oil refinery capacity in the country and is home to a very large petro-chemical industry. These energy sector industries help make Louisiana the second biggest consumer of electricity in the U.S. Louisiana has below average retail electricity prices (EIA 2012d).

Table 32: Louisiana Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
26,744	3,417	--	12.8%	--	--

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

Louisiana has 5,327 MW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the petroleum refining, chemicals, paper, and food industries. Table 33 illustrates the total technical potential for CHP in Louisiana today.

Table 33: Louisiana Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	4,423	629	5,052
Commercial/Institutional	241	34	275
Total	4,664	664	5,327

Sources: See Appendix A

Of the state's over 5 GW of technical potential, only about 264 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 1,485 MW of new CHP installations. Table 34 illustrates the two economic cases for CHP in Louisiana.

Table 34: Louisiana Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			6,890
Remaining Technical Potential	2,549	2,778	5,327
Base Case Market Penetration 2012-2020	188	76	264
Utility Ownership Case Market Penetration 2012-2020	643	842	1,485
Output, million kWh/year			
Base Case Market Penetration 2012-2020	1,514	611	2,125
Utility Ownership Case Market Penetration 2012-2020	5,168	6,782	11,950
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	1,049	428	1,477
Utility Ownership Case Market Penetration 2012-2020	3,564	4,701	8,265

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 35, Louisiana earned 0.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. Louisiana has seen three new CHP installations in the past five years, all of them within the past two years. The installations are: a 300 kW fuel cell installation at an Air Force base, a 4.5 MW natural gas-powered system at a chemical plant, and a 25 MW coal-powered steam turbine system at another manufacturing facility. The state has consistently scored very poorly on CHP policies, and has tremendous room for improvement.

Table 35: Louisiana CHP Policy and Regulatory Environment

Louisiana
Interconnection Standards
Financial Incentives
Financing Assistance
Output-Based Emissions Regulations
CHP in RPS/Energy Efficiency Standards
Net Metering
Other Supportive Policies

Key
Weak
Medium
Strong

Number CHP Installs 2007-2011	3
kW CHP Installed 2007-2011	29,800
2012 Scorecard Score - CHP	0.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Louisiana has a very high amount of installed CHP in place relative to other states, but most of the systems were installed many years ago. The existing systems are generally very large, and powered by the natural gas from the state's many refineries. The state's petro-chemical industry has been a major user of CHP, due to the tremendous economic benefits of large-scale CHP power production onsite.

Louisiana lacks most of the policies available to states to encourage CHP. Louisiana's interconnection standard and net metering rules apply only to CHP systems powered by renewable fuels and only those up to 300 kW in size. The Louisiana Renewable Energy Pilot Program is a "test" renewable portfolio standard to determine whether such a policy would be a wise choice. The voluntary program includes CHP and applies to projects installed through 2014. Currently, there are no financial incentives, financing assistance programs, or output-based emissions regulations in place for CHP.

Concerns about the standby rates used by the state's utilities are regularly voiced among the CHP community. Additionally, regulated utilities are required to use a ratepayer impact measure (RIM) test when evaluating energy efficiency programs. This test does not quantify many of the benefits of CHP systems, leaving CHP programming off the table for most utilities. Utilities are also not able to earn any incentive or cost recovery on investments in energy efficiency, except for Entergy's territory in the city of New Orleans. Such mechanisms are currently being considered for the state as a whole.

NORTH CAROLINA

The bottom line: North Carolina could meet 56 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 36, North Carolina's in-state electric generating capacity is a little under one-half coal based. About 8.5 percent of that is expected to retire, representing a little under one-fifth of the state's total generating capacity. North Carolina is a substantial generator of nuclear-based electricity and it has somewhat average retail electricity rates (EIA 2012d).

Table 36: North Carolina Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
27,674	12,766	2,345-2,373	46.1%	8.5-8.6%	18.4-18.6%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

North Carolina has over 6 GW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the paper, chemicals, petroleum refining, lumber and wood, textiles, and food industries as well as the hospital industry. Table 37 illustrates the total technical potential for CHP in North Carolina today.

Table 37: North Carolina Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	5,242	663	5,905
Commercial/Institutional	282	36	317
Total	5,524	698	6,223

Sources: See Appendix A

Of the state's over 6 GW of technical potential, only about 151 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 1,338 MW of new CHP installations. Table 38 illustrates the two economic cases for CHP in North Carolina.

Table 38: North Carolina Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			1,530
Remaining Technical Potential	2,757	3,466	6,223
Base Case Market Penetration 2012-2020	42	109	151
Utility Ownership Case Market Penetration 2012-2020	256	1,082	1,338
Output, million kWh/year			
Base Case Market Penetration 2012-2020	340	877	1,217
Utility Ownership Case Market Penetration 2012-2020	2,063	8,717	10,780
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	372	979	1,351
Utility Ownership Case Market Penetration 2012-2020	2,249	9,598	11,848

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 39, North Carolina earned 1.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. North Carolina has seen 11 new CHP installations in the past five years, two of them in the past two years. The recent installations are: an 800 kW biomass-powered system at a wood products manufacturing facility, and a 5 kW natural gas-powered reciprocating engine at North Carolina State University's Solar Center. The state has consistently scored poorly on CHP policies, but has improved slightly relative to other states in the recent past. It still has substantial room for improvement.

Table 39: North Carolina CHP Policy and Regulatory Environment

North Carolina	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

Number CHP Installs 2007-2011	11
kW CHP Installed 2007-2011	11,601
2012 Scorecard Score - CHP	1.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

North Carolina offers some lucrative financial incentives for CHP. The Renewable Energy Tax Credit, applicable to CHP since 2010, offers a tax credit equal to 35 percent of the cost of eligible renewable energy property placed into service during the taxable year. This is the highest CHP-specific tax credit available at the state level in the U.S, though there have been no new CHP projects resulting from this tax credit yet. The state's Revolving Loan Program for Renewable Energy and Energy Efficiency authorizes cities and counties to establish revolving loan programs to finance renewable energy and energy efficiency projects that are permanently affixed to residential, commercial or other real property.

North Carolina's interconnections standard, applicable only to investor-owned utilities, lays out three separate tiers of interconnection, in much the same manner as the FERC standards. Systems over 2 MW in size must go through a more extensive study than smaller systems, and application fees scale up in line with system size. The North Carolina Utilities Commission (NCUC) requires the state's three investor-owned utilities to make net metering available to customers that own and operate systems that generate electricity using CHP systems that use waste heat derived from eligible renewable resources up to one megawatt. Currently, there are no output-based emissions regulations in place for CHP.

The state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) does explicitly allow for CHP as an eligible resource, but 2012 is the first year in which utilities are responsible for meeting REPS goals. Notably, the REPS program structure only allows utilities to generate efficiency credits, and since the regulated utilities of the state have no mechanism by which they can get credit or cost-recovery for CHP investments, the inclusion of CHP as an eligible resource remains a moot point.

The utility interest in CHP in North Carolina may be slowly changing. Whereas both Duke and Progress had reportedly engaged in the practice of offering economic development electricity rates to facilities considering CHP—effectively killing the CHP project, Duke has been considering ways in which it could stimulate investment in CHP projects in a manner that would increase shareholder value.

Ohio

The bottom line: Ohio could meet 16 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments.

Coal Situation

As can be seen in Table 40, Ohio relies on coal for about 65 percent of its in-state electric generating capacity. A significant amount of that will likely be retired in the near term, representing around one tenth of the state's total generating capacity. Substantial oil and natural gas resources are currently being sought in two different shale plays. Ohio is one of the nation's top emitters of three of the most regulated pollutants and its retail electricity prices are fairly average (EIA 2012d).

Table 40: Ohio Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
33,071	21,360	2,228-4,498	64.6%	6.7-13.6%	10.4-21.1%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

Ohio has over 9 GW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the chemicals, primary metals, paper, food, and petroleum refining industries as well as the hospital industry. Table 41 illustrates the total technical potential for CHP in Ohio today.

Table 41: Ohio Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	7,630	1,124	8,754
Commercial/Institutional	425	63	488
Total	8,055	1,187	9,241

Sources: See Appendix A

Of the state's over 9 GW of technical potential, only about 74 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 712 MW of new CHP installations. Table 42 illustrates the two economic cases for CHP in Ohio.

Table 42: Ohio Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			521
Remaining Technical Potential	4,079	5,162	9,241
Base Case Market Penetration 2012-2020	64	10	74
Utility Ownership Case Market Penetration 2012-2020	502	210	712
Output, million kWh/year			
Base Case Market Penetration 2012-2020	512	82	594
Utility Ownership Case Market Penetration 2012-2020	4,049	1,692	5,742
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	601	101	702
Utility Ownership Case Market Penetration 2012-2020	4,731	2,095	6,826

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 43, Ohio earned 3.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. The state has seen a number of new CHP installations in the past few years, with four large installations in the past two years alone. A 46 MW waste heat recovery installation at a refinery and a 10 MW biomass-powered installation at a Toledo wastewater treatment plant are indications that the Ohio CHP market continues to be attractive to certain types of CHP projects. However, there is still room for improvement, though recent policy changes have helped make Ohio one of ACEEE's top-ranked states for CHP policy in the country.

The environment for CHP appears to be improving in Ohio. While utilities were cited as major barriers to CHP in previous ACEEE reports, some of the state's biggest investor-owned utilities are reportedly beginning to discuss ways to encourage greater CHP deployment. This is especially true for utilities that are considering investing in CHP themselves, and somehow recovering the costs of the investment.

Table 43: Ohio CHP Policy and Regulatory Environment

Ohio	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

Number CHP Installs 2007-2011	9
kW CHP Installed 2007-2011	118,085
2012 Scorecard Score - CHP	3.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

Ohio's Senate Bill 221 of 2008 established an EERS and an Alternative Energy Portfolio Standard (AEPS), the latter of which technically includes CHP as an eligible resource. However, in practice, CHP is not strongly encouraged by this policy, because the much higher payments available for solar energy resources make CHP less lucrative for utilities to pursue in order to comply with the standard. The EERS did not initially allow CHP to count as an eligible efficiency measure, but the passage of Ohio Senate Bill 315 in 2012 changed this. CHP and waste energy recovery projects can now count toward either the EERS or the AEPS. The Public Utilities Commission of Ohio (PUCO) is in the process of determining the manner in which CHP systems will be credited within the EERS.

There are currently two financial incentive programs in place: tax benefits for air-quality improvements as determined by the Ohio Air Quality Development Authority, and a tax exemption for projects that qualify as AEPS resources. Additionally, the Ohio Energy Loan Fund awards loans to public entities, manufacturers, and small businesses for projects resulting in energy savings of at least 15 percent. CHP projects can take advantage of this financing.

Ohio's other policies that impact CHP are mixed. Ohio's interconnection standards, updated in 2007, now include three tiers to allow for easier and more streamlined applications for systems up to 20 MW, though concerns about the ease with which systems can interconnect remain. Ohio's net metering rules are only applicable to systems powered by renewable resources. Ohio's guidance on its NO_x Budget Trading Program explicitly allows for CHP and other highly efficient processes to count as allowances for energy efficiency and renewable energy NO_x set-asides.

The PUCO is actively supporting increased CHP deployment in Ohio. In collaboration with the DOE, the PUCO has hosted a series of workshops throughout 2012 involving a variety of stakeholders. These workshops are the result of a state resolution passed in February 2012 that codified the state's support for a program encouraging facilities with boilers affected by the impending MACT rules to consider CHP as a compliance and economic development strategy (PUCO 2012). Workshops have also targeted issues particular to CHP such as treatment of CHP in the state's EERS, standby rates, and financial tools.

Additionally, AEP did propose to include a target of 350 MW of CHP and waste energy recovery in its most recent rate plan. Though the initial plan was revoked for other reasons, and the CHP target removed from subsequent plans, it is clear that some of Ohio's largest utilities remain interested in pursuing increased levels of CHP. AEP and other utilities have begun informal discussions with the PUCO and stakeholders about how to ensure reliable cost-recovery and other revenue streams from investments in CHP in the future.

SOUTH CAROLINA

The bottom line: South Carolina could meet 100 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not.

Coal Situation

As can be seen in Table 44, just under one-third of South Carolina's in-state electric generating capacity is coal-based. Only a small amount of its overall capacity is expected to retire. The state's primary source of electricity is nuclear power, and it is a lower-than-average emitter (in lbs/MWh) of a number of critical pollutants. South Carolina has somewhat average retail electricity prices (EIA 2012d).

Table 44: South Carolina Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
23,982	7,230	391-900	30.1%	1.7-3.8%	5.4-12.4%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

South Carolina has 5,391 MW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the petroleum refining, paper, chemicals, primary metals, and food industries. Table 45 illustrates the total technical potential for CHP in South Carolina today.

Table 45: South Carolina Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	4,678	597	5,275
Commercial/Institutional	103	13	116
Total	4,780	611	5,391

Sources: See Appendix A

Of the state's 5,391 MW of technical potential, only about 352 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 1,946 MW of new CHP installations. Table 46 illustrates the two economic cases for CHP in South Carolina.

Table 46: South Carolina Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			1,186
Remaining Technical Potential	1,827	3,563	5,391
Base Case Market Penetration 2012-2020	40	313	352
Utility Ownership Case Market Penetration 2012-2020	280	1,666	1,946
Output, million kWh/year			
Base Case Market Penetration 2012-2020	320	2,519	2,839
Utility Ownership Case Market Penetration 2012-2020	2,258	13,426	15,684
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	351	2,835	3,187
Utility Ownership Case Market Penetration 2012-2020	2,475	14,755	17,230

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 47, South Carolina earned 0.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. The state has seen four new CHP installations in the past few years, with two large installations in the previous two years. One installation is a 20 MW biomass-fueled steam turbine at the DOE-owned Savannah River Site, and the other is a 15 MW biomass-fueled steam turbine at a pulp and paper mill in Bennetsville. There is tremendous room for improvement in the state.

Table 47: South Carolina CHP Policy and Regulatory Environment

South Carolina	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	
Number CHP Installs 2007-2011	4
kW CHP Installed 2007-2011	39,504
2012 Scorecard Score - CHP	0.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

South Carolina has some limited financial incentives for certain types of CHP. Its Biomass Energy Production Incentive provides production incentives for renewable powered CHP systems, which earn $0.01 per kWh for electricity generated and $0.30 per therm for energy produced from biomass resources. The South Carolina Energy Office offers the ConserFund Loan Program to fund energy efficiency improvements in public buildings and non-profit organizations. Priority is given to projects with a fast energy savings payback. "Cogeneration systems that produce electricity and process steam heat for use primarily within a building or complex of buildings" are eligible for the loans.

South Carolina's in-place policies do little to encourage new CHP. In 2006, the South Carolina Public Service Commission enacted interconnection standards for small distributed generation with a maximum capacity of only 100 kW for non-residential systems—much smaller than most CHP systems. The standards do not apply to three-phase generators, and only apply to the state's four investor-owned utilities. South Carolina's largest regulated utilities each have their own net metering rules. In all cases the rules apply only to renewable-powered systems, including those that use biomass and biogas. Currently, there are no output-based emissions regulations in the state. A proposed EERS was not adopted by the legislature in 2009, and the state currently has no RPS or EERS in place.

WEST VIRGINIA

The bottom line: West Virginia could meet 32 percent of its high-end range of coal retirements with cost-effective CHP, provided utilities in the state were incentivized to make CHP investments. They currently are not. It is useful to note that at least half or more of West Virginia's total electricity generation is typically consumed by out-of-state utilities and customers, indicating that perhaps a much larger portion of the in-state generation capacity that actually serves West Virginia customers could be replaced by cost-effective CHP.

Coal Situation

As can be seen in Table 48, almost 90 percent of West Virginia's in-state electric generating capacity is coal-based. A little over one-tenth of it is expected to retire. West Virginia's heavy reliance on coal reflects the fact that it is the second-largest producer of coal in the U.S., behind only Wyoming. West Virginia exports a substantial amount of raw coal as well as coal-fired electricity. In 2010, 56 percent of all the electricity generated inside West Virginia was sent out of state for consumption. It has some of the lowest retail electricity rates in the country (EIA 2012d).

Table 48: West Virginia Likely Range of Coal-Powered Electric Generation Retirements

Total Installed Capacity (MW)	Installed Coal Capacity (MW)	Estimated Retirement Range (MW)	Capacity from Coal	Overall Capacity Retiring	Coal Capacity Retiring
16,495	14,713	1,707-1,842	89.2%	10.3-11.2%	11.6-12.5%

Sources: FBR 2010, SourceWatch 2012, SNL 2011, EIA 2012a, EIA 2012d

Combined Heat and Power Opportunity

West Virginia has 1,689 MW of total technical potential for CHP, including export. The vast majority of this potential is in the industrial sector, with most of the potential in the chemicals and paper industries. Table 49 illustrates the total technical potential for CHP in West Virginia today.

Table 49: West Virginia Technical Potential for Combined Heat and Power

Technical Potential for CHP (MW)	Current	2011-2020 Growth	Total
Industrial	1,413	197	1,610
Commercial/Institutional	69	10	79
Total	1,482	207	1,689

Sources: See Appendix A

Of the state's 1,689 MW of technical potential, only about 71 MW is viewed as economic in the base case. The base case assumes only a 50 percent acceptance of a two-year payback period for a CHP installation, which is a very conservative estimate of industrial or commercial facility investment behavior. If utilities are considered as possible investors, and they are economically encouraged to make investments in CHP, the economic potential is much higher. The utility case, which assumes a 100 percent acceptance of a five-year payback period and a 50 percent acceptance of a ten-year payback period, finds an economic potential of 588 MW of new CHP installations. Table 50 illustrates the two economic cases for CHP in West Virginia.

Table 50: West Virginia Economic Potential for Combined Heat and Power

Market Summary	Onsite	Incremental Export	Total
Capacity, MW			
Existing CHP			382
Remaining Technical Potential	1,213	477	1,689
Base Case Market Penetration 2012-2020	48	23	71
Utility Ownership Case Market Penetration 2012-2020	415	173	588
Output, million kWh/year			
Base Case Market Penetration 2012-2020	389	183	572
Utility Ownership Case Market Penetration 2012-2020	3,348	1,391	4,740
Cumulative Avoided CO_2 Emissions, 1,000 MT			
Base Case Market Penetration 2012-2020	569	264	833
Utility Ownership Case Market Penetration 2012-2020	4,893	2,010	6,904

Sources: See Appendix B

Combined Heat and Power Situation

As seen in Table 51, West Virginia earned 0.5 out of a possible five points in the CHP chapter of the 2012 ACEEE *Scorecard*. The state has seen four new CHP installations in the past few years, with one installation in the last year: a 325 kW natural gas-powered microturbine installation at natural gas compressor station. The state has few supportive CHP policies in place and has substantial room for improvement.

Table 51: West Virginia CHP Policy and Regulatory Environment

West Virginia	
Interconnection Standards	
Financial Incentives	
Financing Assistance	
Output-Based Emissions Regulations	
CHP in RPS/Energy Efficiency Standards	
Net Metering	
Other Supportive Policies	

Key	
Weak	
Medium	
Strong	

Number CHP Installs 2007-2011	4
kW CHP Installed 2007-2011	970
2012 Scorecard Score - CHP	0.5/5

Sources: ICF 2012, ACEEE 2012a, ACEEE 2012b

In 2010 the West Virginia Public Service Commission (PSC) established an order that developed a new interconnection standard. This standard features two tiers of application—with the highest going only up to 2 MW in size—but CHP is an eligible technology. West Virginia's net metering rules were also expanded and improved in 2010. Today there is a system cap of 2 MW, but systems over 500 kW must carry at least $1,000,000 in liability insurance. Systems can only be net-metered if they are powered by renewable fuels or alternative fuels, but, as noted above, the definition of those fuels is expansive.

West Virginia's portfolio standard could be helpful to increased CHP implementation in the near future. In June 2009, West Virginia enacted an Alternative and Renewable Energy Portfolio Standard (RPS) that requires investor-owned utilities with more than 30,000 residential customers to supply 25 percent of retail electric sales from eligible alternative and renewable energy resources by 2025. Interestingly, waste energy is now classified as a renewable fuel and natural gas and other fossil fuels are in fact classified as alternative fuels. This standard will have limited impact until 2015, the first year that utilities will face penalties for non-compliance.

Currently, West Virginia has no financial assistance, financial incentives, or output-based emissions regulations that affect CHP systems. Such incentives or financing assistance could be helpful, as West Virginia has some of the cheapest electricity in the nation. CHP systems are sometimes hard to justify on an economic basis for some would-be customers.

Beyond the RPS, West Virginia utilities are not incentivized to invest in or encourage CHP projects. A proposed energy efficiency resource standard was considered in 2011, but ultimately was not enacted. There is no revenue or cost-recovery structure in place that encourages utilities to make energy efficiency investments, though some limited energy efficiency offerings are beginning to be embedded in recent rate cases before the PSC.

Conclusions

Electric generation in the U.S. is changing significantly. Coal-powered generation has been consistently losing ground to natural gas-based resources, and the economics of coal generation are becoming less and less attractive to utilities around the country. At the same time, new and upcoming environmental regulations will require significant investments in pollution controls at some of the country's oldest coal plants. Owners of many of these plants will likely find that plant retirement is their most economical option, as opposed to making major investments in new pollution control equipment.

For a small number of states, the overall electric-generating capacity to be retired will be significant. New investments in energy resources will be required, and consumers will be paying particular attention to the overall impact of such investments on their electricity bills. Energy efficiency, and CHP in particular, is a cost-effective way to increase system capacity at a cost far lower than most types of traditional electricity generation. CHP is quickly deployable, can use a variety of fuels, and makes substantial economic sense. It's also a cleaner way to generate electricity than all fossil fuel-based approaches because it squeezes far more useful energy out of each unit of fuel. Less fuel is wasted and emissions are reduced.

Despite all of CHP's benefits, its growth in the U.S. has been fairly slow over the last decade. Many states facing significant coal retirements could invest in CHP to cost-effectively fill some of the supply gap left by retirements. However, most of these states lack a number of the policies that could help encourage CHP over traditional energy investments.

States could see substantially higher levels of CHP investment if utilities were encouraged to invest in CHP. Utilities are particularly well-suited to make investments in CHP, but their regulatory structures and business models are not designed to encourage such investments. Changes to the manner in which generating utilities integrate CHP into their energy efficiency programs and earn returns on CHP investments could help usher in a new era of major utility-sponsored CHP investment. Distribution-only utilities could also be encouraged to support customer-side CHP project. For states that are struggling with questions and concerns about the ratepayer impact of investing in pollution controls or new electric-generating assets, CHP could be part of the answer.

The retirement of the estimated 2–5 percent of the nation's total electric generating capacity is not a cause for alarm. It is an opportunity to replace some of the country's oldest, dirtiest, and most inefficient electricity generation with some of the cleanest and most efficient generation available today. Investing in CHP, and encouraging utilities to invest in CHP, will pay dividends in the future as states lock in highly cost-effective electric-generating assets than are cleaner-burning and able to leverage local fuel resources.

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Appendix A: CHP Technical Potential Assumptions and Methodology

Authored by: ICF International

This section provides the methodology for the calculation of the technical market potential for CHP in the industrial and commercial/institutional sectors. The technical potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit customer energy needs. CHP technical potential is calculated in terms of CHP electrical capacity that could be installed at industrial and commercial facilities based on the estimated electric and thermal needs of the site.

CHP is best applied at facilities that have significant and concurrent electric and thermal demands. In the industrial sector, CHP thermal output has traditionally been in the form of steam used for process heating and for space heating. For commercial and institutional users, thermal output has traditionally been steam or hot water for space heating and potable hot water heating.

TARGET APPLICATIONS

This analysis is meant to provide a conservative look at CHP potential and therefore only considers sites with at least 1 MW of CHP technical potential in traditional CHP markets that have high load factors as shown in Tables A-1 and A-2. Low load factor markets and cooling markets (shown in Table A-3) are not included in the estimation of technical market potential for this study, as these markets are less competitive in states with low to moderate electric rates.

The traditional CHP market (Tables A-1 and A-2) represents CHP applications where the electrical output is used to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. The most efficient sizing for CHP is to match thermal output to base-load thermal demand at the site. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load, which means the CHP system will generate more power than can be used on-site if sized to match the thermal load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories make up the traditional CHP market:

High load factor applications: This market provides for continuous or nearly continuous operation of the CHP system. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, and prisons. In three states, this includes CHP at ethylene "cracking" plants, as described in Appendix C.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, health clubs, and laundries.

Table A-1: Traditional CHP Industrial Markets Included in the Technical Market Potential

NAICS	Application	Export Power Potential
311 - 312	Food Processing	Yes
313	Textiles	Yes
321	Lumber and Wood	Yes
337	Furniture	No
322	Paper	Yes
325	Chemicals	Yes
324	Petroleum Refining	Yes
326	Rubber/Misc. Plastics	No
331	Primary Metals	No
332	Fabricated Metals	No
333	Machinery/Computer Equip	No
336	Transportation Equip.	No
335	Instruments	No
339	Misc. Manufacturing	Yes

Table A-2: Traditional CHP Commercial/Institutional Markets Included in the Technical Market Potential Estimate

NAICS	Application	Export Power Potential
2213	Water Treatment/Sanitary	No
92214	Prisons	No
721	Hotels	No
623	Nursing Homes	No
622	Hospitals	No
6113	Colleges/Universities	No

Table A-3: Lower Potential CHP Markets Not Included in the Analysis

NAICS	Application	Load Factor	Export Power Potential
8123	Laundries	Low	No
71394	Health Clubs	Low	No
71391	Golf/Country Clubs	Low	No
8111	Carwashes	Low	No
518	Data Centers	High	No
531	Comm. Office Buildings	Low	No
6111	Schools	Low	No
612	Museums	Low	No
491	Post Offices	Low	No
452	Big Box Retail	Low	No
48811	Airport Facilities	Low	No
445	Food Sales	Low	No
722	Restaurants	Low	No
512131	Movie Theaters	Low	No
92	Government Buildings	Low	No
531	Apartments	High	No

TECHNICAL POTENTIAL METHODOLOGY

Technical potential represents an estimate of the number and capacity of CHP systems that could be used to meet onsite thermal loads and support onsite electric requirements with additional power generation capability available for export to the grid. The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential magnitude and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- Identify existing CHP in the state. The analysis of CHP potential starts with the identification of existing CHP. This CHP electric capacity meeting onsite loads is deducted from any identified technical potential.
- Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy (heating) consumption data for various building types and industrial facilities. Data sources include the DOE EIA Commercial Buildings Energy Consumption Survey (CBECS), the DOE Manufacturing Energy Consumption Survey (MECS) and various market summaries developed by DOE, Gas Technology Institute (GTI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.
- Quantify the number and size distribution of target applications. Once applications that could technically support CHP were identified, the Dun & Bradstreet Hoovers database was utilized to identify potential CHP sites by application and location. The Hoovers Database is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit NAICS/SIC), location (metropolitan area, county, state) and size (employees) for commercial, institutional and industrial facilities. The Hoovers Database was used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kW.
- Estimate CHP potential in terms of MW capacity. In order to estimate the total technical potential for CHP, each of the target facilities in the state needs to have a hypothetical CHP system sized to its electrical and thermal loads. The sum of all the individual CHP system capacities would then result in the overall total CHP potential for the state. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity.
- Subtract existing CHP. After the total CHP potential is derived for all facilities in the region, the existing CHP capacity is subtracted out by application to provide a figure for remaining technical potential in the region.
- Estimate of growth in new CHP capable sites as a function of estimated growth in the applicable sectors.

The technical potential estimates by state are shown in Table A-4.

Table A-4. Technical Market Potential by State

State	Existing Facilities, MW		New Growth, MW		Total, MW
	On-site Electric Use	Export Electric Sales	Onsite	Export	
AL	1,099	3,326	160	445	5,029
CO	675	882	102	113	1,771
GA	2,333	4,541	315	578	7,767
IN	1,388	1,680	232	254	3,553
IA	911	1,797	143	260	3,112
KS	823	1,831	108	180	2,942
KY	1,853	3,010	287	403	5,553
LA	2,220	2,444	329	334	5,327
NC	2,443	3,082	314	384	6,223
OH	3,533	4,522	546	640	9,241
SC	1,616	3,164	212	399	5,391
WV	1,061	422	152	55	1,689

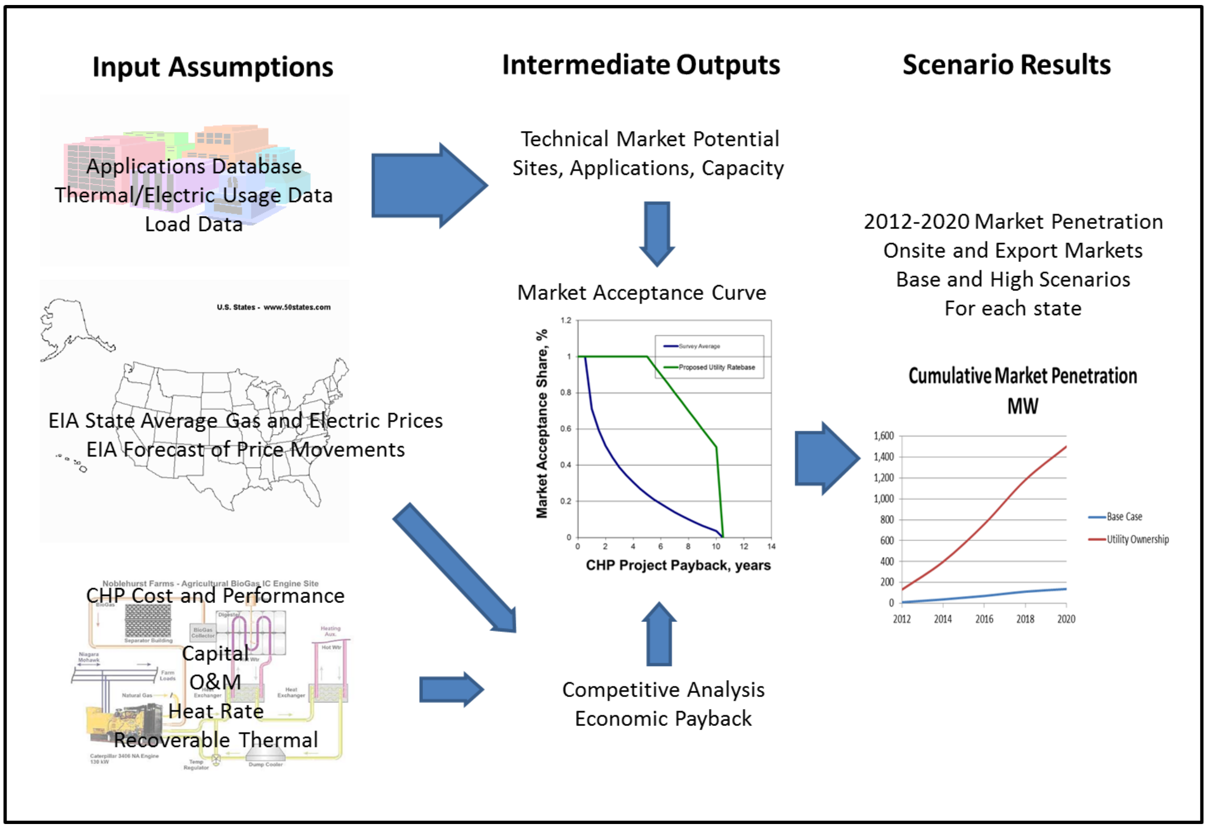
Appendix B: CHP Economic Potential Assumptions and Methodology

Authored by: ICF International

APPROACH

ICF adapted a 50-state CHP market screening model it developed for Oak Ridge National Laboratory for this analysis. The analysis contains the elements, shown schematically in Figure 3, resulting in scenario forecasts of CHP market penetration for the 12 states between 2012 and 2020. The assessment of CHP market penetration is driven by an estimate of the technical potential in suitable applications and an economic analysis of how competitive CHP is in those applications. The competitiveness of CHP in each market segment determines the market penetration.

Figure B-1: ICF CHP Market Model Approach



There are three major types of input assumptions:

- Business applications data that is analyzed to determine the number applicable facilities and potential electric capacity of CHP leading to the estimate of technical market potential
- Gas and electric price estimates for each state analyzed
- CHP cost and performance assumptions.

The energy prices and equipment cost and performance characteristics, along with site electric and thermal load factor assumptions from the business applications analysis, are combined into an economic payback analysis. These economic paybacks are calculated in market segments based on the average characteristics in that segment.

The calculated paybacks determine the market response according to a market acceptance curve that relates the share of customers that will accept the CHP investment based on its payback. This acceptance share enters the market according to a diffusion curve resulting in the final output estimate of market penetration over the forecast period.

ENERGY PRICE PROJECTIONS

The expected future relationship between purchased natural gas and electricity prices, called the spark spread in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP.

For this market penetration analysis, a fairly simple energy price estimation methodology was used:

The current electric prices come from EIA 2010 annual state average industrial prices—the most recent complete year of data reported by EIA at the time the study was undertaken. Even though some of the CHP technical potential is in the commercial sector, the industrial prices were chosen because they better reflect the prices for the larger commercial customers. The EIA commercial price series represents an average of all commercial users, most of whom are too small to economically utilize CHP.

The current average state natural gas price was based on the EIA January to November 2011 average price. The EIA industrial prices are based only on full requirements customers, excluding the customers that purchase gas separately from transportation. This series tends to exclude the largest users. In some states, the reported industrial gas price appears much higher than would be expected for larger users that purchased their commodity gas separately from transportation. In an effort to correct for this issue, the state average industrial gas price was estimated as the lower of the reported industrial price or the city gate price plus $1.00/MMBtu added mark-up.

The outlook for future gas and electric price movements come from the EIA Annual Energy Outlook 2012 Early Release Reference Case, Electricity Market Model (EMM) output. The EMM was used because it provides disaggregated output for 22 electricity subregions whereas the demand-side model contains output for only four regions. The price trends between 2012 and 2020 were based on the appropriate subregion price trends for each state analyzed for the industrial retail electric price (for onsite CHP markets) and the electric sector gas price (for purchased gas for both CHP and avoided boiler use.)

CHP customers cannot save their entire retail cost of electricity with CHP due to customer charges, demand charges, and standby charges. Avoided electric costs due to CHP operation are assumed to equal 95 percent of the average retail rate. This discounting accounts for unavoidable costs such as certain standby, demand, and nonbypassable charges that apply to electric tariffs for customers with onsite generation.

The estimate for the electric wholesale (CHP export) price based on an estimate of the short run average generation cost. This estimate comes from the same EIA AEO forecast. The EIA reported generation component of rates is adjusted by subtracting 1.22012 cents/kWh to remove the capital and fixed costs from the generation resulting in an estimate of running cost only. There was no analysis to determine what specific tariffs were in place in each state for exported CHP power.

The retail electric price forecasts for each state are shown in Table B-1. The average 2010 electric price for the 12 states included in the analysis is just under 6 cents/kWh, more than 20 percent lower than the simple average for the 50 states as a whole. The escalation based on the 2012 EIA AEO2012 early release reference case shows prices staying nearly flat over the 2012-2020 time period—with a range of minus 4 percent to plus 6 percent total change in real price.

Table B-1: Average Industrial Retail Electric Rate Forecast

Average Price by State		Avg. Ind. Electric Rate (cents/kWh), 2010	Average Industrial Electric Price, 2012 Cents/kWh				
State	EIA-NEMS EMM Region		2012	2014	2016	2018	2020
Alabama	SERC / Southeastern	6.01	6.11	6.21	6.16	6.21	6.11
Colorado	WECC / Rockies	6.9	7.01	7.19	7.28	7.30	7.42
Georgia	SERC / Southeastern	6.22	6.33	6.43	6.38	6.43	6.33
Indiana	RFC / West	5.87	5.91	5.85	5.89	5.83	5.82
Iowa	Midwest Reliability Council/West	5.36	5.36	5.27	5.27	5.27	5.22
Kansas	SWPP / North	6.23	6.28	6.28	6.33	6.33	6.18
Kentucky	SERC / Central	5.05	5.15	5.15	5.10	5.05	4.95
Louisiana	SERC / Delta	5.84	5.78	5.86	5.87	5.87	5.90
North Carolina	SERC / Virginia Carolina	6.17	6.22	6.17	6.12	6.08	6.03
Ohio	RFC / West	6.4	6.44	6.38	6.42	6.35	6.34
South Carolina	SERC / Virginia Carolina	5.74	5.78	5.74	5.70	5.65	5.61
West Virginia	RFC / West	5.86	5.90	5.84	5.88	5.82	5.81

The CHP export price forecast is shown in Table B-2. The export price estimates are, on average, 20 percent lower than the retail industrial price estimates, though there is considerable variation by state in the retail to wholesale price ratio.

Table B-3 shows the natural gas price forecast. Natural gas prices increase over the 2012-2020 time horizon by 5-11 percent.

Table B-2: Average Export Electric Rate Forecast

Average Price by State		Average Export Electric Price Estimate, 2012 Cents/kWh				
State	EIA-NEMS EMM Region	2012	2014	2016	2018	2020
Alabama	SERC / Southeastern	5.20	5.30	5.15	5.25	5.05
Colorado	WECC / Rockies	3.60	3.79	3.73	3.65	3.68
Georgia	SERC / Southeastern	5.20	5.30	5.15	5.25	5.05
Indiana	RFC / West	5.33	5.37	5.43	5.42	5.47
Iowa	Midwest Reliability Council/West	3.90	3.75	3.60	3.45	3.35
Kansas	SWPP / North	4.65	4.55	4.50	4.45	4.25
Kentucky	SERC / Central	4.50	4.50	4.35	4.25	4.10
Louisiana	SERC / Delta	4.69	4.60	4.49	4.40	4.39
North Carolina	SERC / Virginia Carolina	5.85	5.75	5.65	5.50	5.40
Ohio	RFC / West	5.33	5.37	5.43	5.42	5.47
South Carolina	SERC / Virginia Carolina	5.85	5.75	5.65	5.50	5.40
West Virginia	RFC / West	5.33	5.37	5.43	5.42	5.47

Table B-3: Average Industrial Gas Price Forecast

State	NG Industrial Rate ($/MMBtu), 2011 Jan-Nov	NG Citygate Rate ($/MMBtu), 2011 Jan-Nov	Adjusted Industrial 2011 ($/MMBtu)	Average Industrial Gas Prices, 2012 $/MMBtu				
				2012	2014	2016	2018	2020
Alabama	$5.72	$5.89	$5.72	$5.52	$5.55	$5.67	$5.67	$5.87
Colorado	$6.16	$5.35	$6.16	$6.00	$5.62	$5.80	$6.17	$6.64
Georgia	$6.35	$5.40	$6.35	$6.13	$6.16	$6.29	$6.29	$6.52
Indiana	$6.22	$4.98	$5.98	$5.80	$5.63	$5.81	$6.01	$6.27
Iowa	$5.63	$5.23	$5.63	$5.44	$5.19	$5.32	$5.56	$5.83
Kansas	$5.36	$6.44	$5.36	$5.14	$4.84	$4.96	$5.19	$5.45
Kentucky	$5.04	$5.22	$5.04	$4.87	$4.91	$4.99	$5.04	$5.23
Louisiana	$4.31	$5.87	$4.31	$4.15	$4.23	$4.26	$4.38	$4.59
North Carolina	$7.47	$5.68	$6.68	$6.44	$6.33	$6.39	$6.50	$6.75
Ohio	$9.83	$5.50	$6.50	$6.30	$6.12	$6.31	$6.53	$6.81
South Carolina	$5.65	$5.94	$5.65	$5.44	$5.36	$5.41	$5.50	$5.71
West Virginia	$4.95	$5.91	$4.95	$4.80	$4.66	$4.81	$4.97	$5.19

CHP Technology Cost and Performance

The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads with CHP. A representative CHP technology was selected to profile performance and cost characteristics in each of the four market size bins used for the analysis as shown in Table B-4. These cost and performance estimates were adapted from an analysis for the California Energy Commission.[8] The costs shown reflect U.S. national average costs which are then adjusted for each state economic comparison (Table B-5), according to state cost index adjustments developed by the Army Corps of Engineers.

[8] Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson, *Combined Heat and Power: 2011-2030 Market Assessment*, ICF International, Inc., California Energy Commission, 2012, CEC-200-2012-002 Rev2.

Table B-4: Representative CHP Technology Cost and Performance by Market Size

Market Size Bin	1-5 MW	5-20 MW	20-100 MW	>100 MW
Technology	3000 kW RE	10 MW GT	40 MW GT	120 MW GT
Capacity, kW	3,000	12,500	40,000	120,000
U.S. Average Capital Cost	$1,700	$1,750	$1,350	$1,200
After-treatment Cost, $/kW	$200	$180	$80	$80
Federal CHP Investment Tax Credit	$190	$193	$54	$0
Total Capital Cost, $/kW	$1,710	$1,737	$1,376	$1,280
Heat Rate, Btu/kWh	9,800	11,765	9,220	9,220
Thermal Output, Btu/kWh	4,200	4,674	3,189	3,189
Electric Efficiency, %	34.8%	29.0%	37.0%	37.0%
CHP Efficiency	77.7%	68.7%	71.6%	71.6%
O&M Costs, $/kWh	$0.0160	$0.0088	$0.0050	$0.0050
Economic Life, years	15	20	20	20
Avoided Boiler Efficiency	80%	80%	80%	80%

Table B-5: State Capital Cost Adjustment Factors

State Adjustments for Capital Costs, $/kW	Adjustment Factor %	3000 kW RE	10 MW GT	40 MW GT	40 MW GT
Alabama	90%	$1,539	$1,563	$1,239	$1,152
Colorado	99%	$1,693	$1,720	$1,363	$1,267
Georgia	90%	$1,539	$1,563	$1,239	$1,152
Indiana	100%	$1,710	$1,737	$1,376	$1,280
Iowa	99%	$1,693	$1,720	$1,363	$1,267
Kansas	95%	$1,625	$1,650	$1,308	$1,216
Kentucky	98%	$1,676	$1,702	$1,349	$1,254
Louisiana	89%	$1,522	$1,546	$1,225	$1,139
North Carolina	83%	$1,419	$1,442	$1,142	$1,062
Ohio	102%	$1,744	$1,772	$1,404	$1,306
South Carolina	84%	$1,436	$1,459	$1,156	$1,075
West Virginia	103%	$1,761	$1,789	$1,418	$1,318

Source: *Civil Works Construction Cost Index System*, Army Corps of Engineers, EM 110-2-1304, March 31, 2011.

ECONOMIC COMPETITIVENESS AND MARKET RESPONSE

The economic competitiveness calculation within the ICF *CHP Market Model* is a simple payback calculation. The payback period is calculated for the representative technology in each size bin. The annual cost of operating the CHP system is compared to the avoided thermal and electric energy cost savings, allowing the number of years it would take for this annual savings to repay the initial capital investment to be calculated. Using a simple payback calculation is a very common form of screening to identify potentially economic investments of any type, and it is used by facility operators and CHP developers in the early stages of identifying economic CHP projects.

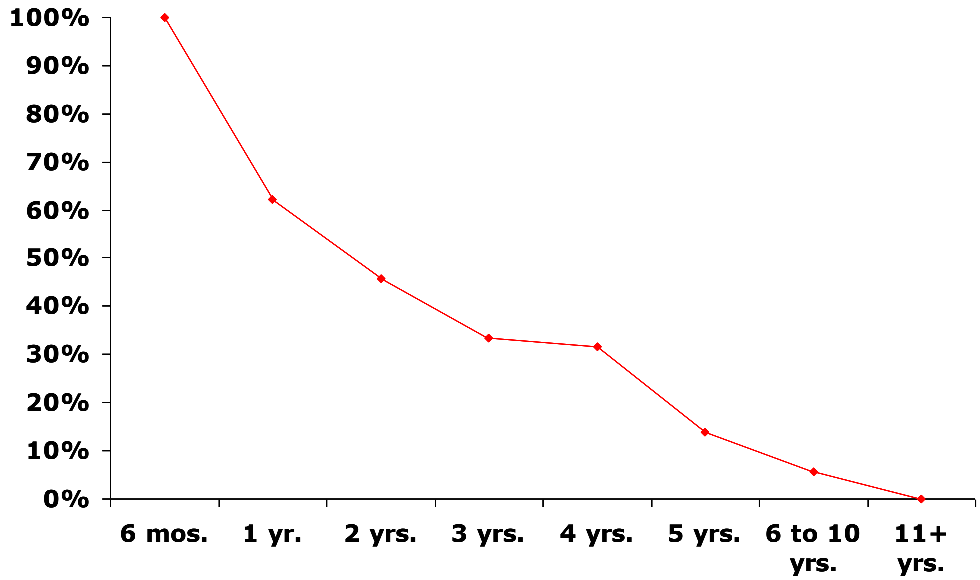
The annual savings calculation consists of the following components:

- CHP operating cost (on a per kW basis)—a function of the system heat rate, the CHP natural gas rate, and the assumed equivalent full load hours of operation per year.
- Avoided electric cost—a function of the CHP hours of operation and the avoided CHP electric costs.
- Avoided boiler fuel—a function of the thermal energy per kWh produced by the CHP system, the assumed percentage of thermal energy utilized, the boiler fuel price, and the boiler efficiency

The payback defines the market acceptance rate which is calculated based on a survey of California business facilities that could potentially implement CHP[9]. Figure 4 shows the percentage of the market that would accept a given payback period and move forward with a CHP investment based on the survey results. As can be seen from the figure, more than 30 percent of customers would reject a project that promised to return their initial investment in just one year, an indication that there is considerable perceived risk in making CHP investments. A little more than half would reject a project with a payback of 2 years. This relationship between payback and market acceptance is used to define the economic market in the base case.

[9] *Assessment of CHP Market and Policy Options for Increased Penetration*, April 2005. EPRI, CEC-500-2005-060-D.

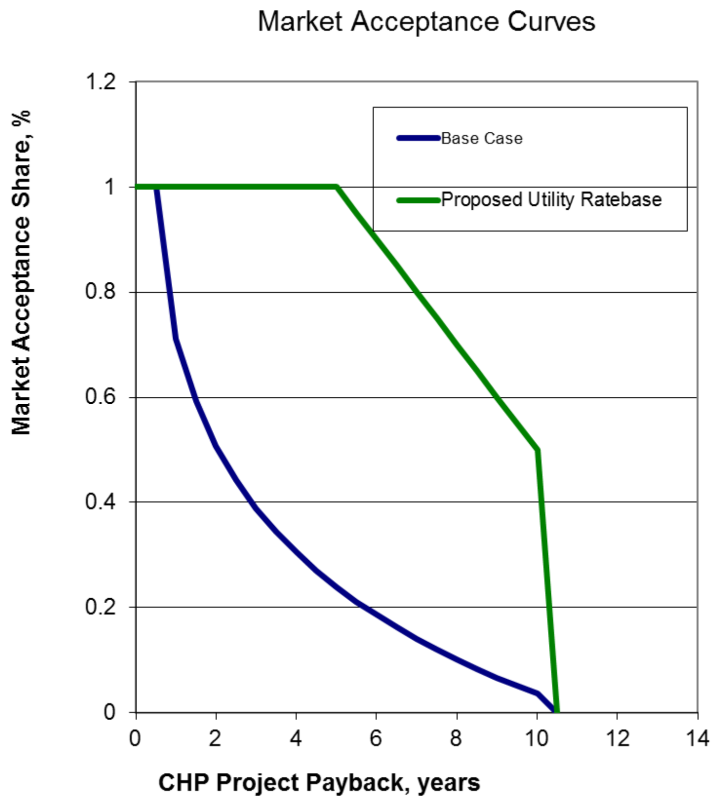
Figure B-2: Base Case Market Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For the high market acceptance case, it was assumed that utility ownership of CHP assets would provide stronger market response for economic payback periods that fall within utility investment criteria. Utility ownership of CHP would mitigate the perceived risk that is reflected in the customer acceptance curve used for the Base Case. Figure 5 shows both the base case and the utility ownership case. In the utility ownership case, it is assumed that 100 percent of projects with a 5-year payback or less will be accepted. Acceptance rates drop off linearly to 50 percent at a 10-year payback. There is no market acceptance for projects with paybacks longer than 10 years.

Figure B-3: Market Acceptance Curve for Utility Ownership Case



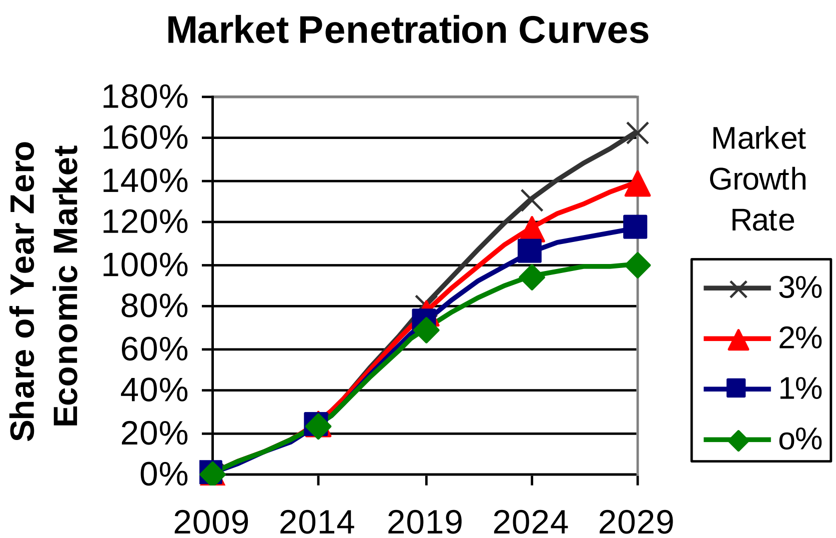
The market acceptance curve defines the market that will ultimately install CHP in their facilities, but all of this economic potential does not penetrate the market at once. The rate of market penetration of the economic market potential is based on a Bass diffusion curve with allowance for growth in the maximum market. This function determines cumulative market penetration for each market period.

Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems because there are a larger number of decision-makers requiring an expansion over time of the number of CHP developers.

Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curve's shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as internal market influence and external market influence.

In the out-years the diffusion curve approaches the underlying growth rate of the market being considered. Figure 6 shows how changing the growth rate of the technical market potential changes the market penetration curve. If the market has no growth (no new facility technical potential) then the cumulative market penetration will approach 100 percent of the existing market in year zero. As the growth rate increases, the market will approach the defined annual growth rate. The use of this functional form allows the model to consider the addition of new technical market potential to the existing technical market potential in an orderly fashion.

Figure B-4: Market Diffusion Curves



The market penetration for each market segment is summed for each scenario to determine the overall market penetration rate. For this analysis there are eight market segments for each state comprised of four market size bins as previously described and two markets—onsite and incremental export.

Appendix C: CHP Potential from Ethylene Production

Authored by: ICF International

Significant ethane production is expected from the surge in natural gas production from shale formations including the Marcellus formation that runs through several states in the East including New York, Pennsylvania, West Virginia, Ohio, and northern Virginia. The Marcellus shale formation could be the largest natural gas deposit in the U.S. Extraction of ethane from this new gas production in the region is expected to stimulate the construction of new chemical plants to produce ethylene by "cracking." Ethylene cracking plants have significant high load factor requirements for heat and electric power that can provide the basis for new CHP capacity in the region.

The team estimated potential new ethylene capacity based on announced ethane production and transportation projects, announced ethylene production, and estimates of CHP capacity based on CHP capacity at existing ethylene production facilities. Table C-1 shows the CHP estimate. The ethylene production estimates for Ohio are based on a proposed ethane pipeline from West Virginia and Pennsylvania. The new production in Louisiana is assumed to come from new ethane pipeline capacity from the Marcellus shale producing region.

Table C-1: Estimate of CHP Potential from New Ethylene Production in the 12-State Region

State	Project	Ethane Production		Ethylene Production	Estimated CHP Capacity
		BBl/day	tons/day	tons/year	MW
Louisiana[10]	Sasol	105,000	4,500	1,500,000	525
Ohio[11]	Mariner West	50,000	2,134	704,375	247
West Virginia	Bayer, PPG	120,000	5,123	1,690,500	592
ACEEE Study 12 State Total		275,000	11,757	3,894,875	1,363

Conversion Factors:

17.6	bbl/ton pressurized ethane
0.75	ton of ethylene/ton of ethane feedstock
0.35	kw/tpy ethylene

[10] Jana Marais, "Sasol Studies $4.5 Billion Ethane Cracker in Louisiana," *Bloomberg Online*, Nov 30, 2.011

[11] G. Kurt Dettinger, "West Virginia's Approach to Attracting Ethane Cracker Investments," *West Virginia Governor's Energy Summit*, 2011.