Combined Heat and Power (CHP) as a Compliance Option under the Clean Power Plan

A Template and Policy Options for State Regulators

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Executive Summary

Combined Heat and Power (CHP) is an important option for states to consider in developing strategies to meet their emission targets under the Clean Power Plan. This Template is designed to highlight key issues that states should consider when evaluating whether CHP could be a meaningful component of their compliance plans. It demonstrates that CHP can be a valuable approach for reducing emissions and helping states achieve their targets.

While actual plans will vary dependent upon state-specific factors and determinations, this Template provides the tools and methodology that states will need to begin the process. If the Clean Power Plan (CPP) is implemented in a form close to what has been proposed, it can support the deployment of CHP. This Template provides key background information to help states incorporate CHP into their plans.

By producing both heat and electricity from a single fuel source, CHP offers significant energy savings and carbon emissions benefits over the separate generation of heat and power. These efficiency gains translate to economic savings and enhanced competitiveness for CHP hosts, and emissions reductions for the state. CHP is already a proven and cost-effective technology, representing 8 percent of electric capacity in the United States (and providing 12 percent of total power generation). Projects already exist in all 50 states and significant technical and economic potential remains. CHP offers a tested way for states to achieve their emission limits while advancing a host of ancillary benefits.

This Template outlines the key issues that any state must consider to incorporate CHP into its CPP plan. As such, it lays out a roadmap for states to pursue to capture the economic and environmental benefits of CHP.

First, it identifies a number of threshold questions that states will need to address when developing their compliance plans. In particular, each state will need to determine:

1. If it will rely on “outside-the-fence” measures such as energy efficiency and renewable energy, rather than rely solely on the limited “inside the fence” options for meeting its emissions limits;
2. If it will pursue a rate-based or mass-based compliance path.
3. If it is taking on any of the emission reduction obligation (“State Commitment”), or if it will impose the full responsibility on power plant owners; and
4. Whether compliance with either rate or mass limits will be measured unit-by-unit, or fleet-wide, and whether to allow trading with other states.

So long as the state determines that “outside-the-fence” measures can be used to support compliance of affected units, CHP is a valuable tool that can fare well under either a rate- or mass-based compliance approach. Indeed, when thermal output is properly accounted, well-designed and properly operated CHP systems generate electricity at a lower effective emissions rate than most affected EGUs and proposed state targets. Alternatively, under a mass-based approach, CHP systems would reduce demand from the affected units and generate credits.

Second, The Template examines how EPA and state air agencies might treat CHP under each of the four “approvability” criteria EPA will use to evaluate state compliance plans (and the measures included in those plans). These include:

1. Enforceability,
2. Performance,
3. Measurement and verification (“M&V”), and

4. Accountability.

Although these four criteria are similar to the elements required in state implementation plans (SIPs) for National Ambient Air Quality Standards (NAAQS), EPA has stated that the approvability criteria in CPP plans "need not be identical" and they are generally understood to be less demanding. The Template demonstrates that CHP is likely to fare very well under each of the four approvability criteria. It emphasizes that it is the emissions target that is enforceable, not specific projects. Thus, if a CHP system fails to perform as expected, the state can adopt alternative approaches to reduce emissions (e.g., other energy-efficiency measures, increase reliance on renewables, etc.). Most CHP projects as a matter of standard business practice are metered and annual performance is monitored. Accordingly, EPA recognizes CHP as a compliance option for which "M&V approaches are well-established." CHP should easily be able to satisfy the Accountability criteria if the state plans include mechanisms to report progress and to correct for any shortfalls.

Third, the Template recommends a process for states to follow if they wish to include CHP in their compliance plans. These include:

- Surveying CHP potential,
- Establishing an interagency working group,
- Determining ways to generate value for CHP hosts,
- Informing large customers that CHP investments can earn carbon-reduction credits,
- Adopting an EM&V protocol,
- Building on existing programs, and
- Identifying and removing barriers to development.

The Appendices offer further exploration and details.

In Appendix A, the Template identifies dozens of programs that states have already adopted to advance CHP and which could assist a state in deploying new CHP. The Appendix does not select a particular approach, but demonstrates the range of options that are available (both in terms of geography and nature of the policies). While policies that are successful in one state may not be suitable in another, Appendix A provides some initial background and resources to enable others to learn from their experience. The Appendix identifies three broad categories of programs (Financial Incentives, Regulatory Support – e.g., streamlined permitting, Creating Markets). In addition to a brief description about each successful program, it provides links to the enabling legislation or other resources.

Appendix B provides a more detailed discussion of the enforceability of CHP programs under the Clean Power Plan. It concludes that EPA is very unlikely to disapprove a CHP component of a state plan due to concerns about enforceability. It finds that EPA is likely to approve state plans that:

- Make reasonable assumptions about the performance of the CHP elements of the plan,
- Identify a party that is responsible for any state incentive programs designed to generate emission reductions or credits from CHP,
- Rely on established EM&V protocols, and
- Include correction or contingency mechanisms if projected strategies underperform.

Appendix C explores different approaches for measuring carbon dioxide emission reductions from CHP. This includes translating output (MWh) to emission reductions, with sample calculations for different types of technologies and fuel types (including biomass). Appendix C also includes discussion about options for determining what the CHP system is displacing (e.g., average grid emissions v. emissions during peak use).

Finally, Appendix D provides a brief description and links to key publications about CHP.

Introduction

EPA's proposed rule to regulate Carbon Dioxide (CO_2) emissions from existing electric power plants (Clean Power Plan or CPP) could provide a powerful new driver to advance the deployment of Combined Heat and Power (CHP) if it is implemented in its current form and supporting programs are properly designed and structured as part of state compliance plans. The proposed plan allows states to use "outside the fence" measures such as end-use efficiency as a means to achieve emissions targets. By producing both heat and power from a single fuel source, CHP is significantly more efficient than central power generation. CHP is a proven and demonstrated approach to lowering emissions, making U.S. manufacturers more competitive, and enhancing electric reliability. CHP can produce large blocks of low-cost energy and carbon savings. Strategies to increase deployment of CHP as part of a carbon-pollution reduction plan could be an attractive option for state air and energy regulators. New revenue generation opportunities or incentives associated with CO_2 reductions could help overcome some of the barriers that have historically impacted CHP development in commercial, institutional and industrial settings. This could be particularly attractive to large customers considering CHP, as there may be novel ways to offer and receive credit for CHP systems in addition to ratepayer efficiency programs. States will need guidance and technical assistance on how to design programs around industry needs that satisfy EPA's compliance requirements. Fortunately, best practices in technology, policies, programs and measurement and verification (M&V) exist for CHP, and can be tailored to meet individual state needs.

This document summarizes how states and utilities can use CHP as a compliance option under the CPP, and how a CHP pathway can be designed as a compliance option to meet the requirements set by EPA for state compliance plans. The rule is expected to be finalized in summer 2015, after which states and power plant owners will have between one and two years to develop compliance plans. State agencies, large electric customer groups and others can use this period to popularize CHP as an effective CO_2 compliance option and secure mechanisms by which CHP is recognized (and rewarded financially) as an emissions reduction strategy under the CPP.

The Clean Power Plan

The proposed Clean Power Plan sets state-specific emission targets. EPA's final regulations are likewise expected to establish emissions goals for each state. The regulations will also provide states with guidance for designing and implementing the various elements (both required and discretionary) of state plans. In its June 2014 proposal, EPA signaled that it would grant states broad flexibility to choose a policy pathway, provided that states can demonstrate their plans will achieve the assigned state target within the prescribed timetable. EPA also provided initial guidance on what measures could be counted toward achievement of a state goal, and how those measures might be counted.

The state plan must meet the requirements of the final EPA guidelines to gain EPA's approval. If the plan does not meet the requirements and EPA does not approve the plan, the Clean Air Act stipulates that EPA must impose a federal plan for that state. Although states will not know the specifics of the regulations until EPA releases the final rule in late-summer 2015, states are nevertheless beginning to evaluate their policy options for CPP compliance.

CHP Offers Significant Benefits

The CPP creates a new opportunity to stimulate investment in CHP for the mutual benefit of manufacturing, commercial and institutional building owners, electric utilities and power plant owners:

- CHP is a large, low-cost emission-reduction opportunity.
- CHP is often a less expensive means to reduce power plant CO_2 emissions, compared to "inside the fence" options.
- A CHP pathway in a state compliance plan can help increase the productivity and competitiveness of a state's industrial and commercial base, enable industrial plants, commercial buildings and institutional campuses to contribute to GHG reductions, and provide a new revenue stream or other financial incentives to encourage investment in CHP.
- CHP investments tend to stabilize the industrial and commercial base in a service territory and can be utilized to help resolve electric transmission and distribution system problems that would otherwise require more expensive electric utility capital investment.
- CHP compliance pathways may align with existing state and utility programs designed to accelerate the deployment of CHP within states.

EPA, DOE and others have long recognized CHP's environmental, economic and reliability benefits. Appendix D provides an annotated collection of key materials considering the barriers and opportunities to CHP deployment. CHP compliance pathways under the CPP could bring significant new financial value to encourage CHP investment by owners of manufacturing, commercial and institutional facilities. State compliance plans under the CPP can be designed to shorten the investment payback of CHP, provide customers with a hedge against electric power prices, and lower the overall cost of CO_2 controls for utilities and ratepayers.

CHP Is Already Fueling the American Economy

Thomas Edison included a CHP system when he built the world's first commercial power plant in 1882. At the time, Edison produced both electricity and thermal heat while using waste heat to warm neighboring buildings. Today, there are more than 4,200 CHP installations in every state in the country. (Figures 1 and 2). Combined, these projects produce nearly 83 gigawatts of clean and efficient power – the equivalent of more than 166 conventional power plants. This represents 8 percent of U.S. electric capacity and roughly 12 percent of U.S. generation. Each year these systems are running, they avoid more than 1.8-quadrillion Btus of fuel consumption and 241-million metric tons of emissions compared to the separate production of heat and power.

CHP systems operate under a wide variety of ownership structures, including systems owned by industrial facilities, CHP systems jointly operated and owned by industrial customers in partnership with utilities, and CHP systems operated by third-party independent power producers (IPP) who supply some combination of thermal energy and electricity to an industrial host and in some cases surplus electricity to the utility grid. Each of these ownership structures can be used to produce emission reduction credits under EPA's CPP.

Figure 1. Existing CHP Capacity by State[1]

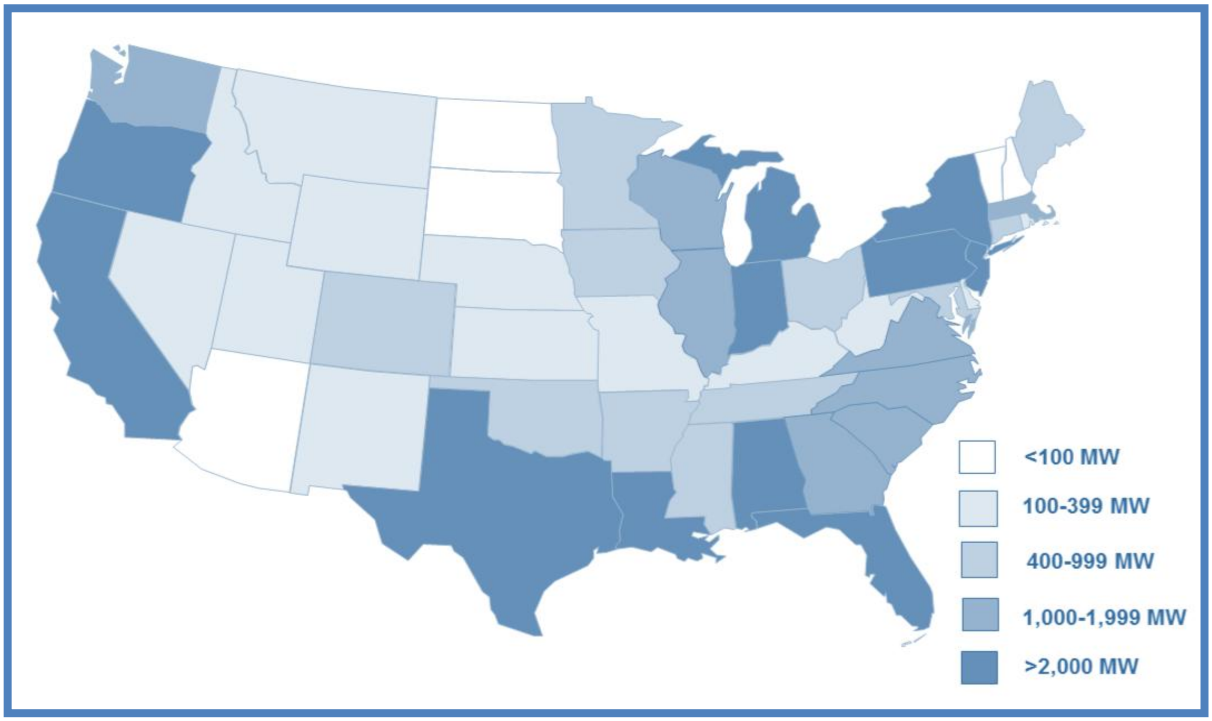
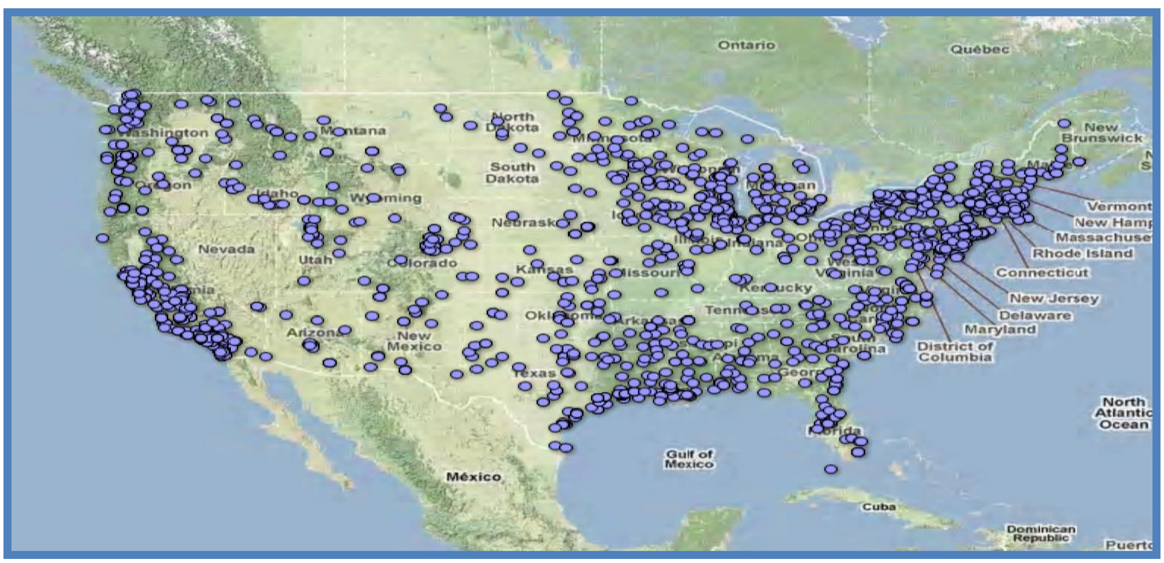


Figure 2. Existing CHP Installations (2014)[2]



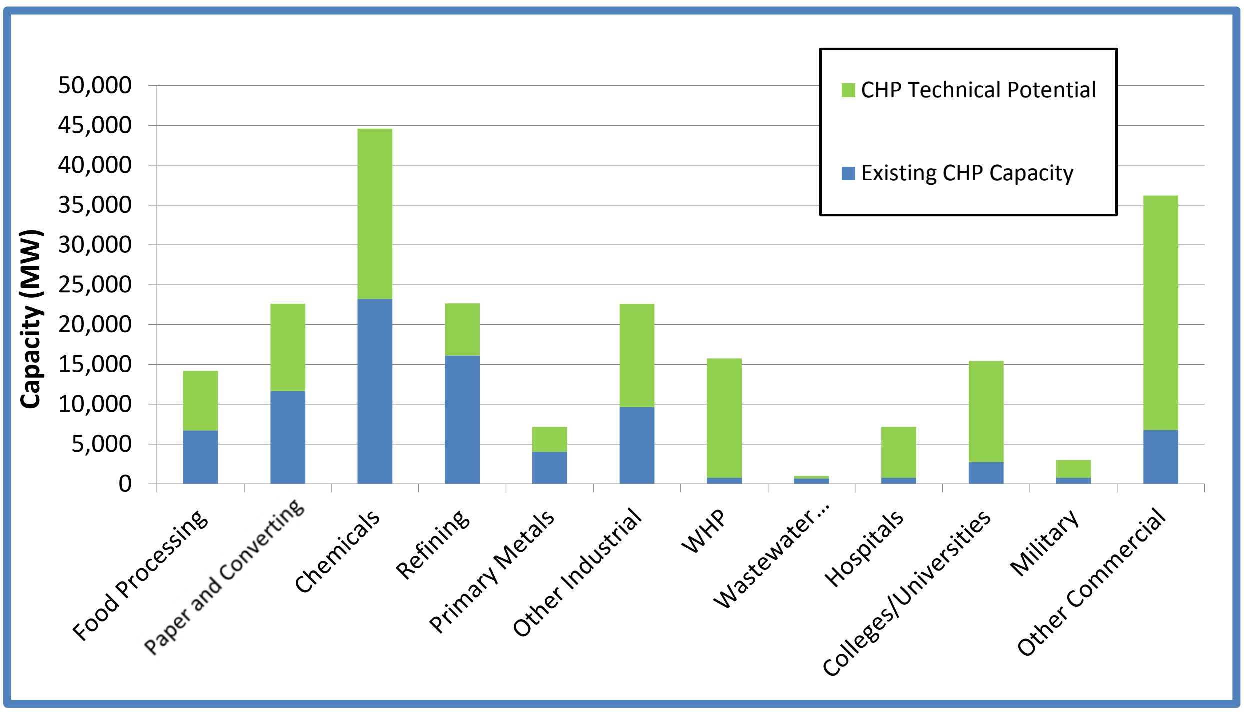
[1] U.S. DOE CHP Installation Database. Maintained by ICF International. U.S. Installations as of December 31, 2014. https://doe.icfwebservices.com/chpdb/

[2] U.S. DOE CHP Installation Database. Maintained by ICF International. U.S. Installations as of December 31, 2014. https://doe.icfwebservices.com/chpdb/

There Is Significant Opportunity to Increase CHP Deployment

While CHP is already fueling America's factories, tremendous potential remains to increase deployment and make American businesses and institutions more competitive and resilient, while reducing emissions. In fact, the Department of Energy and Environmental Protection Agency have identified as much as 130 gigawatts of remaining CHP technical potential – the equivalent of 260 conventional power plants. (Figure 3).[3] To date, U.S. CHP deployment has been concentrated in the industrial sector; however, tremendous opportunity remains in hospitals, universities, and multi-family housing, with future potential roughly equally divided between the commercial and industrial sectors. (Figure 3). Unlike other clean-energy sources, deployment is not limited to places where the sun is shining or the wind is blowing. CHP provides an available, reliable clean-energy solution for every state in the United States. (Figure 4). A recent report by the National Association of Clean Air Agencies (NACAA) identifies CHP as "one of the most cost-effective strategies for reducing CO_2 emissions economy-wide."[4] For this reason, it is a key option that states may consider when determining how to achieve CPP emission targets.

Figure 3. Remaining CHP Technical Potential by Sector[5]

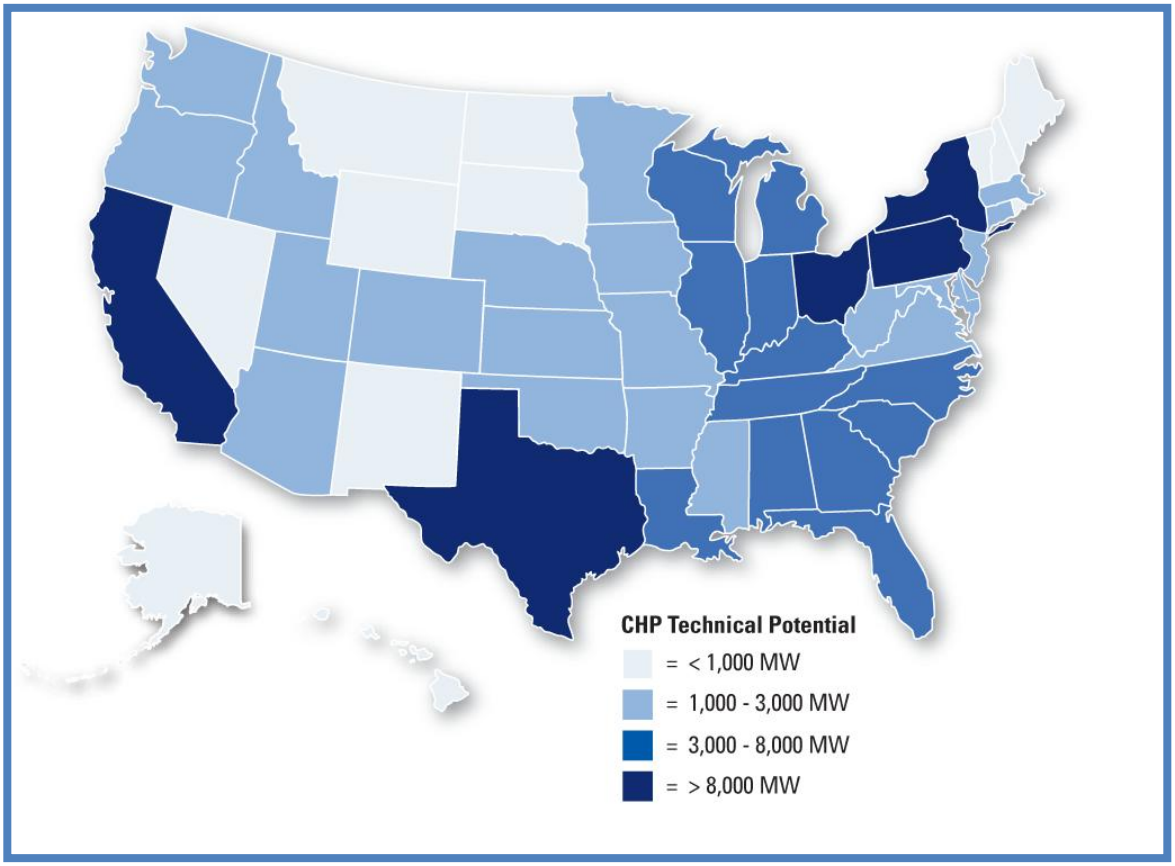


[3] Note that technical potential provides an estimation of market size constrained only by technological limits — the ability of CHP technologies to fit customer energy needs. *It does not include economic or other considerations relevant to a decision to invest in CHP.*

[4] National Association of Clean Air Agencies (NACAA), May 2015, "Implementing EPA's Clean Power Plan: A Menu of Options," at 3-14 (http://www.4cleanair.org/NACAA_Menu_of_Options).

[5] Existing Capacity - U.S. DOE CHP Installation Database. Maintained by ICF International. U.S. Installations as of December 31, 2014. https://doe.icfwebservices.com/chpdb/. Technical Potential - ICF Internal Estimates, 2013.

Figure 4. Remaining CHP Technical Potential by State[6]



CHP in the Clean Power Plan

In designing a compliance plan under the CPP, states initially need to make several threshold decisions that are independent of the question whether to include CHP in a compliance strategy:

1. The state needs to decide if it will rely, in part, on cost-effective "outside-the-fence" measures such as energy efficiency and renewable energy, rather than rely solely on the limited "inside the fence" options for altering power plants.
2. States need to decide if they will pursue a rate-based or mass-based compliance path.
3. Each state needs to decide if it is taking on any of the emission reduction obligation ('State Commitment"), or if it will impose the full responsibility on power plant owners.
4. The state needs to decide whether compliance with either rate or mass limits will be measured unit-by-unit, or fleet-wide, and whether to allow trading with other states.

[6] ICF Internal Estimates, 2013.

These choices will be determined by a number of factors that are beyond the scope of this guide. But clearly, as long as the state decides to rely on outside-the-fence measures, whichever other forks-in-the road are chosen, CHP can be an effective element of a broader compliance plan.

EPA is expected to issue the state goals in a rate-based form, meaning the state must not exceed a certain level of emissions per unit of power generated by covered power plants (i.e., lbs/MWh). Alternatively, states will have the option to adopt a mass-based equivalent of the rate-based target EPA prescribes. Under this approach, covered power plants would not exceed an aggregate emissions level (in tons) that is derived from the rate-based standard prescribed by EPA for the state. As noted above, the decision to pursue either a rate-based or mass-based approach is a threshold determination for each state. CHP is a viable compliance option under either approach.

CHP under a Rate-Based Approach

Under a rate-based approach, states will have specific emissions-rate targets (i.e., lbs CO_2/MWh) that must be met over time (these targets may be enforceable at the state, utility, or affected-EGU level, depending how individual state compliance plans are structured). When thermal output is properly accounted, well-designed and properly operated CHP systems generate electricity at a lower effective emissions rate than most affected EGUs and proposed state targets. Under EPA's proposed rule, CHP can generate emissions reduction credits that can help states of affected EGUs meet their emissions targets.

CHP may be able to directly derive value for its emissions reductions under a rate-based approach, either through direct incentives to stimulate CHP investment to help states meet their targets, or through market-based mechanisms that allow power plant owners (affected entities) to purchase certified savings credits from an emissions registry or directly from end-use customers or other entities that invest in CHP.

Under a rate-based approach, CHP generation and emissions savings data can be used to affect "corrections" to both the numerator and denominator of the equations used to set the state's targets and performance (as illustrated in Appendix C). Under the final rule, each state will likely be assigned an emission limitation representing the allowable average emission rate for all affected power generation in that state. To achieve the target, power plant owners must reduce the total emissions from power plants relative to the total amount of electric power generated. States can help power plant owners do this through programs that incentivize CHP investment and other energy- efficiency measures that can be more cost- effective options compared to "inside the fence" measures such as power plant heat- rate improvements or repowering.

CHP under a Mass-Based Approach

Under a mass-based approach, the state's rate-based emissions targets are converted into overall emissions limits expressed in terms of annual tons of CO_2 released. CHP deployment reduces the need for power generated from the grid, thereby lowering the emissions from affected EGUs. CHP development could be incentivized through existing state or rate- payer programs, or through allowance set-asides in cap and trade programs.

Is CHP Compatible with Criteria Used by EPA to Approve State Compliance Plans?

EPA proposed four general criteria it will use to evaluate state compliance plans and emissions reduction measures. Although these four criteria are similar to the elements required in state implementation plans (SIPs) for National Ambient Air Quality Standards (NAAQS), EPA states in the proposed rule that "approvability criteria for [Clean Air Act] section §111(d) plans need not be identical to approvability criteria for SIPs."[7]

Enforceability

The exact meaning of "enforceability" in the context of the Clean Power Plan is still uncertain.[8] However, most analysts believe that the enforceability criterion will likely be applied differently for state compliance plans under §111(d) than it has historically been used for state implementation plans to meet National Ambient Air Quality Standards (NAAQS) under §110 of the Clean Air Act. The final EPA rule is expected to clarify how state plans can meet the enforceability criteria, but the language of the proposed rule suggests strongly that CHP elements of a state compliance plan can designed to achieve plan approval under the eligibility criteria.

For a measure is to be federally enforceable a state would likely need to commit to evaluating its effectiveness and include potential corrective actions in its plan. Establishing enforceability has historically involved demonstrating that the measure is mandatory and that legal authority has been granted by legislation and/or regulations to the relevant governing body to enforce the measure.[9]

In general, a key to meeting the enforceability criteria under §111(d) is to identify a responsible party operating under state law, interagency agreements, regulatory requirements, contracts or other requirements to implement each emissions reduction measure (and to find additional emissions reductions to compensate for any shortfall). Responsible parties could include the affected EGUs, the state, or even third parties such as distribution utilities. For example, a state agency or utility responsible for implementing an incentive program to increase investment in CHP could be identified as the party responsible to carry out, evaluate and report on the effectiveness of the measure. Typically these entities will have a web of statutes, regulations, utility commission orders or contracts that establish commitments to carry out the measures relied on, or referenced in, the plan. Hence, in drafting a compliance plan states must consider who is responsible for implementing CHP, and develop corrective measures if these elements of the plan underperform.

A measure may help a state plan meet the enforceability criteria without necessarily being "federally" enforceable itself. A measure becomes federally enforceable when the state includes the measure in its formal implementation plan. But the proposed rule suggests that a state may alternatively rely on "complementary measures" (such as a CHP strategy) that are not federally

[7] U.S. EPA, June 2, 2014, 79 Fed. Reg. 34830, 34909, "Proposed Rule: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units."

[8] EPA sought comment on this issue in the proposed Clean Power Plan (79 Fed. Reg. at 34909).

[9] U.S. EPA, 2012, "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans.".

enforceable, as long as there is a commitment by the state to adjust its plan to address any emissions reduction shortfalls associated with implementation of such measures.

It is not necessary to include all emission reduction measures from individual projects in the *federally* enforceable portion of the state plan. In fact, states are more likely to be successful at incentivizing private entities to invest in cost-effective CHP projects if these projects are *not* subject to the perceived risk of federal enforcement or citizen suits under the federal Clean Air Act. This can be accomplished for example under either a "state commitment approach" or "complementary measures approach" described in the proposed rule which make the overall state target the federally enforceable provision in the state plan. Under these approaches, it is only the state emission rate target (or mass emission limit), and EGU specific permit limitations, that constitute the federally enforceable elements in the state plan. A state's plan would demonstrate how it would achieve the targets through EGU-specific permit requirements, while referencing state "commitments," or "complementary measures", including CHP programs, that will help meet those limits. The programs themselves would not, therefore, be federally enforceable, but would give EPA sufficient confidence that the plan as a whole meets the general enforceability criteria of the EPA rule.

Since the emission targets in the state plan itself, rather than the individual elements of a compliance strategy, are likely to be enforceable under this approach,[10] end users that participate in a state or utility CHP program that generates credits for CPP compliance would not be subject to state or federal enforcement. As voluntary suppliers of emission reduction credits, their only obligations would be to satisfy the terms of legally binding emission credit sales contracts, agreements, or efficiency programs under which they receive financial incentives. Similarly, states will not face penalties if a CHP program does not deliver as expected. Rather, the state would monitor overall performance of each element in its strategy, periodically report progress to EPA, and if the overall mix of strategies is underperforming, it will make adjustments in programs and strategies to make up the short fall. Such adjustments need not be specific to the CHP elements of the plan. (See Appendix B for a more detailed discussion of enforceability).

Performance

State compliance plans must show that they will reduce the emission rates of affected EGUs to the required standard of performance within the designated timeframe. This means that the state plan needs to reasonably project how the various elements of the plan will achieve emission targets, and ensure that actual emission rates or tonnage of emission reductions is consistent with the target at the end of each compliance period. Because compliance plans are

[10] Under this approach, a state compliance plan may project that a set of CHP incentives (managed by a state agency or under a utility DSM program) will achieve a certain amount of energy savings or CO_2 tonnage reductions. The state strategy is enforceable because it is based on a series of contractual agreements with entities that receive incentives or other financial support to invest in CHP. If those CHP incentives fail to produce the estimated energy savings, neither that state, nor participants in the program are subject to federal enforcement. It is the overall performance of a state plan that is federally enforceable, and if one strategy falls short it may be made up by over-performance from other plan elements, or by corrective measures (to improve the CHP strategy, or other elements of the compliance plan) taken in later years of the applicable three-year compliance period.

forward looking, each state will need to develop a reasonable forecast of the energy savings it expects to achieve through CHP based on the potential for CHP development in the state and the anticipated impact of state or utility programs to promote CHP development.

Measurable, Quantifiable and Verifiable

State plans must detail how emissions reductions can be quantified and verified. For CHP, states operating under a rate-based system will need to adopt a set of evaluation, measurement and verification (EM&V) protocols by which to measure the energy savings produced by CHP measures and determine the resulting emissions reductions.

These criteria can be easily met by CHP projects. Most CHP projects as a matter of standard business practice are metered and annual performance is monitored. A number of states have adopted standard protocols to evaluate CHP project performance (e.g., Massachusetts, New York, Maryland, California, Illinois, New Jersey) and many utilities have long experience with similar protocols under traditional demand-side management programs. Recognizing this, EPA explicitly identified CHP as a compliance option for which EM&V is well established.[11] Where the state has assumed some part of the emission reduction obligation (via a state "commitment"), any plan to achieve part of that reduction via CHP and industrial energy efficiency more broadly should include an EM&V plan and identify the responsible implementation entity.

State plans will also need to detail how energy savings from CHP result in CO_2 emissions reductions. The EGU emission reduction impacts of CHP are similar to those of other end-use energy efficiency measures. Like other energy-efficiency investments, CHP reduces demand – and thus the associated emissions – from affected EGUs. As such, the methodology used for crediting emission reductions caused by new and up-graded[12] CHP should be equivalent to the methodology used for crediting other end-use energy-efficiency measures. However, unlike end-use efficiency, implementation of CHP often results in incremental fuel use – and incremental CO_2 emissions – at the host facility. It is unclear at this time whether EPA, in the final rule, will recognize the full kWh output of CHP systems to determine emissions reductions or require the netting out of incremental site emissions. If the latter is required, the credit calculation should be simple, accurate and understandable. CHP's efficiency and emission benefits derive from producing *both* electricity and useful thermal energy simultaneously from a single fuel source. There are accepted output-based emissions measures that account for both the thermal and electric outputs of the system and that appropriately account for the emissions benefits of CHP (see appendix B).

Accountable

State plans must include mechanisms to report progress toward the applicable emission target and to take corrective actions if performance under the plan *as a whole* falls short. It should not be a problem that there will be some uncertainty about performance of particular CHP measures

[11] This recognition is reflected in a technical support document accompanying the proposed rule Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, State Plan Considerations, Docket ID No. EPA-HQ-OAR-2013-0602 June 2014, at 47-49.

12 Up-graded CHP units refers to expansion or efficiency improvements to existing CHP systems in a state compliance plan. Indeed, there will be some level of uncertainty about every element of a state's plan. It is the collective impact of all strategies that matters, not the performance of any one element of the plan. Accountability will be determined based on a state's ability to monitor performance over time and to identify correction/ contingency mechanisms if projected strategies underperform.

Steps toward a CHP Compliance Module

The following are key steps a state can take to evaluate and configure a CHP compliance module:

Survey CHP Potential and Build on Existing State and Utility CHP Programs

A first step to including CHP in a state CPP compliance plan is to collect information on the CHP potential in a state or utility service territory. Most states will have access to studies and databases that quantify the commercial, institutional and industrial base and associated thermal loads.[13] A variety of public and private organizations have already produced both national and state-specific estimates of CHP potential, which can inform this assessment.[14]

Steps to Establish a CHP Compliance Pathway

1. Assess the CHP emissions reduction potential and experience under existing policy supports
2. Build on existing programs and/or create new options for large energy intensive businesses
3. Clearly inform large customers that CHP investments can earn carbon reduction credits
4. Adopt an Evaluation, Measurement and Verification (EM&V) protocol
5. Estimate energy savings or emission reductions to be achieved from CHP.
6. Identify barriers to CHP investment and apply appropriate programs and policies to overcome the barriers

Next, the state must gain an understanding of existing state or utility programs to support CHP development. The fastest and most effective way to integrate CHP into CPP compliance is establish or expand existing state or utility CHP programs. Many states have already adopted policies to advance CHP investment (Appendix A),[15] often in the form of state or utility programs that incentivize CHP investment and/or reduce barriers to market development. Such policies and programs can take various forms: cash grants to offset capital costs, performance incentives tied to electric output, low-cost financing, streamlined permitting and interconnection standards, and tax credits. States

[13] *See, e.g.,* DOE State Energy Database System.
[14] *See e.g.*, "The Opportunity for Combined Heat and Power in the United States", American Gas Association, 2013, https://www.aga.org/opportunity-chp-us; "Assessment of the Technical and Economic Potential for CHP in Minnesota", Minnesota Department of Commerce Division of Energy Resources, 2014, http://mn.gov/commerce/energy/images/CHPTechnicalandEconomicPotential.pdf
[15] *See also* EPA CHP Policy Portal, http://www.epa.gov/chp/policies/database.html. Note that Appendix A profiles a wide range of existing policies, however, inclusion in the Appendix does not reflect an endorsement of a particular approach. Moreover, not every policy will be appropriate in each state.

without existing incentives can adopt successful programs from other states, modified to appeal to the particular mix of industrial customers and thermal loads.

Illustrative Interagency Division of Responsibilities for a CHP Module

Public Utility Commission

- Approve utility or state-based incentives
- Address cost recovery for utility programs
- Address regulatory barriers to CHP

State Air Quality Agency

- Write and submit plan
- EPA Point of contact
- Under mass-based compliance system, manage set aside for CHP
- Agreements with other states on cross-state credit trade or ownership
- Manage any corrective actions

State Energy Offices

- Forecast MWh or CO_2 impacts (provide to air quality staff)
- Develop and define EM&V plan
- Outreach to CHP host community
- Monitor progress and report results
- Host registry or certification mechanism for CO_2 reduction credits

Where a state plans to use utility or state-based incentives, it will generally be helpful to establish multi-agency teams to coordinate actions and establish a clear division of labor. The text box above shows one way that roles can be assigned among participating agencies – though clearly many other combinations are possible.

Evaluate the Options for Large Customers to Earn Tradable Carbon Reduction Credits

States or utilities could create "standard offers" to purchase emission reduction credits from industrial, commercial or institutional customers who make investments in CHP.[16] This model can work either with CHP units owned by industrial power customers or by CHP systems that are owned and operated by third-party independent power producers (IPP) who operate a CHP system on an industrial site with thermal energy and electricity being supplied to the industrial host. The compensation for and transfer of emissions reduction credits can be done either as an element of a state or utility CHP incentive program, or where such programs do not exist, as a

[16] Utilities can also consider partnerships in which shared ownership or operation of a new CHP system could help meet both utility and customer needs at lower cost than separate power generation and thermal systems. As described in the Menu of Options (Appendix A), many utilities have already pursued such partnerships.

separate, market-based mechanism involving bilateral transactions between affected EGUs and CHP investors. This latter option may be especially important in states where industrial customers have opted-out of state or utility incentive programs. Utility purchases of emission reduction credits could be combined with traditional incentive programs to create fixed revenue streams for large customers making CHP investments.

It will be difficult to estimate the financial value of emission credits generated by CHP systems until there is a final EPA rule and states have drafted compliance plans. Even after the regulatory mechanisms are in place, the price of emission reduction credits may be hard to predict. This suggests that states might combine multiple strategies to incentivize CHP. An example of this hybrid approach would be to establish or continue traditional forms of performance-based CHP incentives (e.g. those run by the New York State Energy Research & Development Authority),[17] and allow the incentive recipients to retain ownership of the associated emission reduction credits. The state program administrator could then periodically adjust the traditional incentive payments (up or down) to reflect the value that CHP investors will be able to secure from the sale of the emission reduction credits into CO_2 compliance markets. This would create a stable, ongoing revenue stream that would help attract large industrial, commercial and institutional customers to make CHP investments. Under this scenario, in order to avoid double counting, the state would not take credit for the CO_2 emission reduction value of its CHP incentive program as a “state commitment” in its CPP compliance plan. The plan could, however, explicitly allow power plant owners a pathway for doing so (e.g. through a “set aside” of allowances under a mass-based control program, or crediting/EM&V or registry mechanism under a rate-based compliance plan) to secure credits for use in EGU compliance demonstrations.

Adopt an Evaluation, Measurement and Verification (EM&V) Protocol

Any CHP pathway will require accurate measurement of the performance and efficiency of installed CHP systems. Most operators of CHP systems routinely measure these values as part of their standard approach to monitoring and evaluating project performance. States that have implemented CHP incentive programs including New York, Massachusetts, New Jersey and Maryland have developed detailed EM&V protocols that include standards for specific CHP system parameters to monitor meter types, meter placement, frequency of data collection and performance calculations. These protocols can be readily adopted as part of a state’s CPP compliance plan.[18]

[17] Such incentives are based on how well the system actually performs – considering performance factors such as annual electricity generation (kWh), overall fuel conversion efficiency (FCE), or summer-peak demand reduction (kW),

[18] As part of this, a state might create a registry and certification process by which a state agency or third party will carry out the EM&V process for large customers. This will help reduce the cost and uncertainty associated with data collection. EM&V can be a complex process; however, if the state simplifies the process and inspires confidence that the credits and compliance revenues will flow back to large customers, more facilities might choose to invest in CHP. In addition, a state might establish an emission credit certification mechanism or registry, to make it easier to record and trade credits generated by CHP investments. Under such a certification mechanism, a state agency or third-party verification agent would carry out the EM&V for the CHP host. A registry, like those currently used to track Renewable Energy Credits (RECs) for RPS compliance (and for voluntary renewable energy markets), could be used to certify and track emission reduction credits.

Estimate Energy Savings and Emission Reductions

Based in part on the CHP potential studies and experience with utility and state-based incentive programs, the state should make a realistic estimate of energy savings and emission reductions that they expect the CHP strategy to produce.[19] These estimates will feed into the broader portfolio of emission-reduction strategies included in the state compliance plan.

Identify and Remove Barriers for CHP Development

CHP projects face a host of market, regulatory and business barriers that impact project costs and customer decisions.[20] At the same time, traditional regulatory structures governing electric utilities are giving way in many states to new approaches that place greater value on distributed generation, pollution control, and load reduction. Opportunities exist to develop assistance programs, enact regulatory changes, and develop state and/or utility-support programs to promote accelerated CHP deployment. An important step to make CHP a viable CO_2 compliance option is to identify these barriers, bring them to the attention of the utility regulators and other state agencies, and to seek necessary policy changes. There are numerous examples of programs and actions implemented in various states that can serve as starting points for potential state programs and regulatory changes. (Appendix A)[21]

Suggested Elements of a CHP Compliance Pathway

A state should consider a number of template elements when incorporating CHP in a CPP compliance plan. Different levels of rigor may be required depending on the compliance plan approach adopted by the state:

1. Overview of Combined Heat and Power
    a. Definition of CHP and CHP measures as part of a compliance plan
    b. Efficiency, emissions and economic benefits of CHP
    c. Potential of CHP deployment (market sectors, MWs, timing)
    d. Role of CHP in a state compliance plan
2. CHP as a compliance option
    a. How CHP produces emissions reductions at affected EGUs
    b. Assumptions around CHP deployment, savings, and compliance estimates
3. Quantification of emission savings potential
    a. Methodology for calculating electricity demand reductions, and associated CO_2 savings, attributable to CHP
    b. Data assumptions and sources
    c. Potential emission reductions from CHP, including a timeline for those reductions

[19] These estimates should be conservative, especially in the early years. CHP investments require considerable planning and construction time (and may need to be timed to correspond with capital investment or production cycles).
[20] Oak Ridge National Laboratory, 2008, "Combined Heat and Power: Effective Energy Solutions for a Sustainable Future", http://info.ornl.gov/sites/publications/files/Pub13655.pdf; DOE-EPA, 2012, "Combined Heat and Power: A Clean Energy Solution", http://www.epa.gov/chp/documents/clean_energy_solution.pdf
[21] *See also* EPA CHP Policy Portal - http://www.epa.gov/chp/policies/database.html

4. Implementation
    a. Status of and experience with CHP deployment in the state
        i. Current and projected prices for natural gas and electricity
        ii. Technical resources available to support CHP development
    b. Identify Barriers to implementing CHP and Potential Solutions
        i. Up-front costs for the user
        ii. Permitting and siting
        iii. Utility interface
            a. Interconnection
            b. Standby tariffs
            c. Sale of excess power
        iv. Lack of awareness
        v. Undeveloped sales and service infrastructure
        vi. Lack of institutional capacity to support interested users
    c. Program elements and policy actions that would increase CHP implementation (opportunities both within and outside of rate-payer based programs)
        i. Financial assistance
        ii. Regulatory support
        iii. Creating markets
    d. Entities responsible for implementation

5. Monitoring and reporting
    a. Process by which CHP implementation will be monitored and evaluated
    b. Applicable EM&V protocols
    c. Entities responsible for monitoring
    d. Sources of data and relevance (fuel input, net electricity generation, net useful thermal energy recovery)
    e. Process for overseeing data monitoring and reporting

6. Enforceability (in general, the state plan is enforceable, but individual measures are not)
    a. Entities responsible for program implementation
    b. Entities with jurisdiction to enforce CHP compliance measures
    c. Process for enforcing CHP compliance measures
    d. Corrective actions and shortfall remedies available to the state

7. Verification and quantification
    a. Verification process for electricity savings attributable to CHP
    b. Entities responsible for verifying electricity savings
    c. Process for reporting and verifying electricity savings
    d. Process for quantifying emissions reductions

Conclusion

CHP can make significant contributions to state compliance with carbon emission reductions under EPA's CPP. The decision to include CHP as a compliance option rests with states, utilities, and key stakeholders. The benefits of including CHP in state compliance plans would accrue to power plant owners, large electric customers, gas and electric utilities, and the general public. CHP is completely compatible with the purpose and structure of EPA's CPP regulation. Over the next 12 to 18 months, utilities, end-users, CHP advocates and state agencies should work together to adopt CHP as a compliance mechanisms to reduce electric sector demand and CO_2 emissions.

Appendix A

Combined Heat and Power: A Menu of Options to Support Deployment[22]

Table of Contents

The Table of Contents for Appendix A provides access to a sampling of successful policies that states have adopted to encourage deployment of Combined Heat and Power (CHP). As illustrated in the following pages, successful policies have been adopted in virtually all states and are not limited by geography or politics. This list is not intended to be prescriptive. Policies that are successful in one state may not be suitable in another. Instead, these policies reflect the wide array of options available to states to advance CHP as part of their Clean Power Plans and provide some initial background and resources to enable others to learn from their

[22] Note that for many of these policies, CHP may be eligible alongside other clean or renewable energy sources. Thus, the listed policies may support CHP because it is among eligible resources.

experience. EPA maintains a comprehensive overview of CHP policy profiles in its CHP Policies and Incentives Database (dCHPP). This Appendix highlights a subset of those policies that are recognized as being the most successful. A list of all state policies cited herein is provided at the end of Appendix A.

Financial Assistance

While CHP systems offer long-term economic savings, they require a substantial up-front economic investment. Some developers and project hosts are often looking for projects with an eighteen-month pay-back period, but a large-scale CHP installation may take 7-10 years to see a return on investment. Policies that provide financial support can help reduce this initial hurdle and help projects "pencil out."

CHP costs vary depending on the prime mover and the capacity of the installed system, with average capital costs ranging from $1,200 to $4,000 per kilowatt depending on technology, size and site conditions.[23] Total installation cost of a 3-megawatt CHP system can range from $5.7 million to over $10-million dollars.[24] Due to economies of scale, larger systems are cheaper to install per kilowatt than smaller units. Since industrial CHP applications are likely to be substantially larger than commercial installations (due to high heat loads and significant on-site electricity demand), these systems may be more cost-effective. In fact, the vast majority (86 percent) of existing capacity is in the industrial sector.[25] Maintenance costs will likewise vary by type, size and engine speed of the system.

Despite the up-front investment required, CHP systems provide significant long-term economic savings by reducing purchased electricity demand and insulating hosts from volatile electricity prices. Return on investment will vary depending on the technology type, location, price of electricity and fuel, among other variables. Because these factors vary by project, CHP system owners report payback periods ranging from 1.5 years to 12 years, with a large number of opportunities anticipating payback between 5 to 10 years."[26] Favorable financial policies can help reduce this payback period and make CHP projects more attractive investments.

Financial incentives like the federal Investment tax credit can reduce up-front costs, thereby lowering the payback period. States can also offer additional financial incentives for CHP projects in the form of rebates, grants, loans, and tax deductions.[27]

[23] EPA, Sept. 2014, "Catalog of CHP Technologies," at Table 2-4 (http://www.epa.gov/chp/documents/catalog_chptech_full.pdf) (reporting capital costs ranging from $1,200 to $4,300/ kW (small microturbine on the small side, large gas turbine on the high side of range) dependent on prime mover and size).
[24] *Id.* (Tables 3-4 and 3-5).
[25] ICF, 2015, Combined Heat and Power Installation Database (http://www.eea-inc.com/chpdata/index.html).
[26] AGA, May 2013, "The Opportunity for CHP in the United States," at Table ES-1 (reporting approximately 35 GW of projects with a payback between 5 to 10 years compared to 6.4 GW with a payback of less than 5 years given current technology costs and electricity prices) (https://www.aga.org/sites/default/files/sites/default/files/media/the_opportunity_for_chp_in_the_united_states_-_final_report_0.pdf).(https://www.aga.org/sites/default/files/sites/default/files/media/the_opportunity_for_chp_in_the_united_states_-_final_report_0.pdf).
[27] ACEEE, "Policies and Resources for CHP Deployment: Financial Incentives" (http://www.aceee.org/sector/state-policy/toolkit/chp/financial-incentives).

States and utilities have adopted a wide variety of financial supports for CHP, including:

- State **grants**, **loans**, and **utility rebates**.
- State **bonds**.
- **Commercial PACE programs** that allow building owners to receive full financing for eligible energy-saving measures, repaid as a property tax assessment for up to 20 years.
- Discounted **utility** rates.

State **tax credits** or **favorable tax treatment** (e.g., exempting CHP investments from property or income tax).

State Grants, Loans and Utility Rebates

A variety of grants and low-interest loans exist to help finance clean-energy investments, including CHP. These programs may be financed by utilities as part of their compliance with portfolio standards. By reducing upfront costs, such programs lower the payback period for eligible projects.

Alabama – The Energy Division of the Alabama Department of Economic and Community Affairs administers the AlabamaSAVES revolving loan fund program, which includes a budget of $50 million dollars. Revolving Loan Funds are structured so that the repayment of a loan is recycled to be loaned out again in support of another project, providing a continuous source of loan funds. The interest rate is one percent and the loan length is a maximum of 10 years. Closing costs are 1.75 percent of loan origination fee. The loans may be used to purchase and install equipment for renewable-energy systems and energy-efficient fixtures and retrofits installed on property owned and/or operated by an eligible business. CHP is considered an eligible technology under this program, with loans ranging from $50,000 to $4-million.

Arizona – Southwest Gas' Arizona Smarter Greener Better Distributed Generation program offers its customers rebates ranging from $400-$500 per kW of installed capacity (up to 50 percent of the cost of the qualifying project) as part of its energy efficiency program. The Company offers incentives to qualifying commercial and industrial facilities that install efficient CHP systems. Incentives vary based upon the efficiency of the installed system. The minimum efficiency for all systems is 60 percent. Contractors are also encouraged to participate in the program. A partial rebate is provided after the equipment is purchased, following the submission of the project application and the engineering study. The utility then verifies the installation, operation, and energy savings before providing the remainder of the rebate.

California – The Self Generation Incentive Program (SGIP) provides incentives to renewably fueled and fossil-fueled CHP systems. All of California's major investor-owned utilities participate. The maximum incentive is $5 million with a minimum 40 percent customer investment. Eligible system size is capped at 3 MW and must meet a 60 percent minimum efficiency requirement. The incentive is $1.13 per watt for renewably fueled CHP and $0.46 per watt for conventional CHP systems.

Connecticut – In 2014, the Connecticut Department of Energy and Environmental Protection (DEEP) released a draft Integrated Resource Plan proposing to offer incentives of up to $450/kWh for up to 160 MW of new CHP capacity in the state. The incentives will decline over time, as the state's deployment goals are met.

Connecticut also offers low-interest loans (one percent below the customer's applicable rate, not greater than prime rate) to support the installation of customer-side distributed resources (including CHP systems larger than 50 kW). The minimum loan size is $1,000,000 for a program total of $150-million.

Section 7 of Public Act No. 12-148 requires the Connecticut Department of Energy and Environmental Protection (DEEP) to establish a $15 million Microgrid Grant and Loan Program to support distributed energy generation at critical facilities. Critical facilities are defined as, "any hospital, police station, water treatment plant, sewage treatment plant, public shelter, or correctional facility, any commercial area of a municipality, a municipal center…" The loans are to be used for the cost of design, engineering, and interconnection of microgrid systems. Recipients of funding must submit an annual report to DEEP and the Connecticut Public Utilities Regulation Authority about the status of the recipient's microgrid project. An initial round of grants was issued in 2013 under the Microgrid Grant and Loan Program. A new round of grants was announced in October 2014.

Illinois - In June 2014, the Illinois Department of Commerce and Economic Opportunity (DCEO) established a pilot program that provides cash incentives, up to $2 million, for individual CHP projects in Illinois public sector facilities. Incentives are performance-based and are paid out at various phases of the project (design, construction, and production). For Conventional CHP systems to qualify, the minimum measured performance level must be an annual energy efficiency of 60 percent high-heating value (HHV) with at least 20 percent of the system's waste heat energy output in the form of useful thermal energy utilized in the facility.

Maryland - In September of 2012, Baltimore Gas and Electric (BGE) launched a Combined Heat and Power pilot program as part of the BGE Smart Energy Savers Program. The CHP program provides incentives to industrial and commercial customers who install efficient (>65 percent higher-heating value) CHP systems. Incentives are partly performance based and provided for design, installation, and construction to offset costs developers face throughout the process. In September 2013, BGE received approval from the Maryland PSC to expand this program, due in large part to the positive reception that BGE received from its commercial and industrial customers. The program now offers an additional $10 million in funding (It had originally been approved for $2 million). These Programs were approved by the PSC in Order No. 84955 as part of a combined filing (case numbers 9153 through 9157) in which Maryland's Electric Utilities applied for approval of their Energy Efficiency, Conservation and Demand Response Programs pursuant to the EMPOWER Maryland Energy Efficiency Act of 2008. Accordingly, in addition to BGE, First Energy, PEPCO, Delmarva and Southern Maryland Electric Cooperative offer similar CHP incentive programs.

Massachusetts –The Mass Save CHP program was created to implement the Green Communities Act of 2008, which recognizes CHP as an energy-efficiency measure eligible for utility incentives. The program offers in-state CHP system-owners incentives to increase deployment. The incentives are tiered (ranging from $750 to $1,200), with larger incentives (covering up to 50 percent of installed costs) given to the most efficient systems. Incentives are also offered to cover up to 50 percent of the cost of feasibility studies.

New Jersey – In the wake of Superstorm Sandy, New Jersey created the Energy Resilience Bank (ERB) with the goal of investing in long-term recovery strategies focused on critical facilities and enhancing energy resilience. The ERB will finance the design, acquisition, construction, and installation of distributed energy resources at certain critical facilities. Financing includes both grant funding and longer term, low-interest loans. Grants and forgivable loans will be offered to address up to 40 percent of unmet funding needs, while low-interest, amortizing loans will be available for the remaining 60 percent of unmet funding needs. Both fossil-fueled and renewably fueled CHP systems are eligible for the program.

New York – Established in 2013, the CHP Accelerator program is sponsored by NYSERDA and provides incentives for the installation of pre-qualified, pre-engineered CHP systems by pre-approved CHP system installers (see system catalog for listings). Eligible project sizes range from 0.05 to 1.3 MW. The maximum incentive per project is $1.5-million, with a total program budget of $20-million. All incentive payments are made through the CHP system vendor.

Ohio – Dayton Power & Light launched a CHP rebate program in 2015**.** Qualified projects will receive a rebate based on rated design capacity ($100/ kW) and kWh generated ($0.08/ kWh) during the first year the project is commissioned. Generation rebates will be paid in two installments at 6 and 12 months; capacity will be paid upon project completion. Rebates are based on the final cost of the project, and will be limited to 50 percent of the total design and construction cost, with a total cap of $500,000/ project. Eligible projects must have an annual energy efficiency of 60-percent high-heating value (HHV) and a payback period based on electricity cost savings of less than 7 years.

Bonds

Through state bonding authorities, a bond (financial security) may be issued by state and local authorities as a way for agencies to borrow money at low-cost to invest in operational endeavors and projects, including clean energy and CHP.

Hawaii – The Hawaii Department of Business, Economic Development, and Tourism issues Green Infrastructure Bonds to help developers of clean-energy installations (including CHP) on commercial or residential properties secure low-cost financing. The bond proceeds will be used to fund the on-bill financing program being developed by the Public Utilities Commission. Bondholders will be repaid with funds collected from the state Public Benefits Fund.

Minnesota – In 2012, Minnesota policymakers approved $64.1 million in bonding that will allow the University of Minnesota to make improvements to its campus infrastructure. Of that $64.1 million, $10 million is being dedicated to a CHP project, designed to replace current coal furnaces.

New Mexico – New Mexico's Energy Efficiency and Renewable Energy Bonding Act authorizes up to $20 million in bonds, backed by the State's Gross Receipts Tax, to be issued to finance energy efficiency and renewable energy improvements in state government and school buildings. The bonds are exempt from taxation by the state. Projects financed with the bonds will be paid back to the bonding authority using the savings on energy bills. At the request of a state agency or school district, the New Mexico Energy, Minerals and Natural Resources Department will conduct an energy assessment of a building to determine specific efficiency measures which will result in energy and cost savings. A state agency or school district may install or enter into contracts for up to 10 years for the installation of energy efficiency measures on the building identified in the assessment. Any type of renewable energy system and most energy-efficiency measures, including energy recovery and CHP systems, are eligible for funding.

Commercial Pace Programs

Property Assessed Clean Energy (PACE) financing is an innovative way to finance energy-efficiency upgrades to buildings. Interested property owners evaluate measures that achieve energy savings and receive 100 percent financing, repaid as a property-tax assessment for up to 20 years. This allows property owners to pursue qualifying energy-efficiency upgrades with no up-front costs.

California – The California Statewide Community Development Authority's CaliforniaFIRST Program is a finance program for non-residential properties. The program allows property owners to finance the installation of energy and water improvements and pay the amount back on their property tax bill. Eligible projects include renewable energy generation projects using fuel cells and energy efficiency projects involving "cogeneration furnaces". A property owner can finance the equipment, labor, design, audit, permits and engineering of a project. The minimum amount that can be financed is $50,000. The maximum financing amount is dependent on the property value. Current outstanding debt plus CaliforniaFIRST financing amount must be less than the property value plus the value of the financed projects. Repayment periods will range from 5-20 years, depending on the expected useful life of the financed improvements and terms negotiated with lender.

Connecticut – C-PACE allows commercial, industrial or multi-family property owners to access 100 percent up-front, long-term financing for energy efficiency and clean energy improvements on their properties through a special assessment on the property tax bill, which is repaid over a period of years (up to 20 years). Although there is no financing minimum, C-PACE is best suited for capital improvements over $150,000. CHP is highlighted as a recommended measure for industrial property owners. To qualify, projects must result in an energy savings-to-investment ratio greater than 1 over the lifetime of the assessment term and be permanently affixed to the building or property.

Michigan – The City of Ann Arbor offers Property Assessed Clean Energy (PACE) financing to commercial and industrial property owners for energy efficiency and/or renewable energy projects, including CHP, that range in size from $10,000 to $350,000. Financing will be conducted by pooling the assessments and issuing a bond once the pool reaches $1 million. The interest rate is expected to be less than 5 percent. CHP systems and biomass thermal systems must include the appropriate air pollution controls. The project costs cannot exceed 20 percent of the property's State Equalized Value, and the lien to value of the property cannot exceed 99 percent of twice the State Equalized Value. Projects must demonstrate that energy savings will be greater than the cost of the project and will undergo a voluntary special assessment as part of the application process.

Discounted Natural Gas Rates

Gas utilities can encourage CHP investments by offering reduced rates to CHP hosts.

California – California natural gas utilities can provide natural gas to qualified cogeneration systems under the same distribution rates offered to large electric utilities per Order Number 92792 and Public Utilities Code (PUC) Section 218.5. This is a significant discount over the distribution rates charged to non-CHP commercial and industrial uses. Eligible CHP facilities must operate at 42.5 percent efficiency (i.e., minimum PURPA efficiency).

New York – Since 2003, New York customers using natural gas for distributed generation including CHP have been able to qualify for discounted natural gas delivery rates. In April 2003, the New York Public Service Commission (NYSPC) issued procedures for developing gas-delivery rates that the local gas distribution companies (LDCs) would exclusively apply to gas-fired distributed generation (DG) units.

Pennsylvania – Philadelphia Gas Works offers discounted gas rates for commercial and industrial customers who use natural gas in any combination of cooling, heating and power production.

New Jersey – New Jersey Natural Gas offers a discounted gas rate for residential and commercial customers with distributed generation. South Jersey Gas offers a special rate designed to incentivize CHP applications.

Favorable Tax Treatment

Tax policies can significantly affect the economics of investing in new onsite power generation equipment such as CHP. Several states have instituted specific tax exemptions and tax credits to promote the deployment of efficient CHP projects.

Connecticut – Connecticut municipalities are authorized, but not required, to offer a property tax exemption lasting up to 15 years for qualifying CHP systems installed on or after July 1, 2007. Municipalities that adopt an ordinance to provide such an exemption may require a payment in lieu of taxes from the property owner. Owners of CHP systems located in commercial, industrial, residential, multi-family residential, and agricultural facilities where the facility capacity does not exceed the electricity load for the location are eligible.

New Jersey – In 2009, New Jersey established a sales and use tax exemption for the purchase of natural gas and utility service for on-site cogeneration facilities.

New Mexico – New Mexico offers a 6 percent tax credit for qualifying clean-energy projects, including “recycled energy.” Any unused credit may be carried forward for up to 10 years. The tax credit amount is capped at $60 million. Recycled energy is defined to include projects that convert the otherwise lost energy from the exhaust stacks or pipes to electricity without combustion of additional fossil fuel." Qualifying projects must be smaller than 15 MW.

North Carolina – North Carolina offers a tax credit equal to 35 percent of the cost of eligible renewable energy property (including CHP fueled by non-renewable fuels) placed into service in North Carolina during the taxable year. There is a maximum of $10,500 per installation for CHP systems or certain other renewable-energy systems used for a non-business purpose. There is a maximum of $2.5 million per installation for all CHP systems (as defined by Section 48 of the U.S. Tax Code) and biomass applications used for a business purpose, meaning the useful energy generated by the property is offered for sale or is used on-site for a purpose other than providing energy to a residence. Renewable-energy equipment expenditures eligible for the tax credit include the cost of the equipment and associated design; construction costs; and installation costs less any discounts, rebates, advertising, installation-assistance credits, namereferral allowances or other similar reductions provided by public funds. Eligible systems must be placed in service before the end of 2015.

Ohio – Ohio may provide a 100 percent sales and use tax exemption for certain tangible personal property for industrial and commercial property owners. Qualifying energy conversion facilities are those that are used for the primary purpose of converting natural gas or fuel oil to an alternate fuel or power source. Thermal efficiency improvement is defined as "the recovery and use of waste heat or waste steam produced incidental to electric power generation, industrial process heat generation, lighting refrigeration or space heating."

The Ohio Air Quality Improvement Tax Incentives Act also allows a 100 percent exemption from the tangible personal property tax (on property purchased as part of an air quality project), real property tax (on real property comprising an air quality project), a portion of the corporate franchise tax (under the net worth base calculation), and sales and use tax (on the personal property purchased specifically for the air quality project only) for outstanding bonds issued by OAQDA. Furthermore, interest income on bonds and notes issued by OAQDA is exempt from state income tax (and may be exempt in certain cases from the federal income tax). OAQDA provides assistance for new air quality projects in Ohio for both small and large businesses. Such assistance extends to any energy efficiency or conservation project.

Regulatory Support

CHP installations are complex projects, which trigger a variety of air and utility commission permitting requirements. States can encourage projects by offering regulatory assistance – by supporting developers and users through the process, relaxing permit requirements for "straightforward" projects, and by adopting standardized interconnection processes and rate design that recognizes the potential benefits of natural gas CHP to electric and gas systems.

State and utility regulations can encourage CHP by offering:

- **Technical assistance** to help guide developers through the permitting process
- **Streamlined permitting** for small to mid-size projects
- Federal and state environmental regulations that support CHP through their specific inclusion or with **output-based limits** for thermal and electrical outputs
- Transparent and uniform technical standards, procedures, and agreements governing **interconnection** to the grid
- **Rates** that reflect actual costs and benefits of CHP systems on electric and natural gas systems

Technical Assistance

New York – The New York State Energy Research and Development Authority's (NYSERDA) Flex Tech Program provides New York State industrial, commercial, institutional, government, and nonprofits with technical assistance to help them make "informed energy decisions." The goal of the FlexTech program is to increase the productivity and economic competitiveness of facilities by identifying and helping assist with the development of certain energy efficiency projects, including CHP. The program provides cost-sharing (up to $1-million) for a range of studies, including CHP project classification studies and industrial process efficiency analysis. For CHP project classification studies, site-specific technical requirements and economic feasibility of installing natural gas-fired CHP are assessed. To be eligible, the proposed CHP system must be less than 50 MW, more than 60 percent efficient, and use at least 75 percent of the produced electricity on site.

United States – DOE offers a variety of technical support for industrial facilities:

DOE funds seven regional CHP Technical Assistance Partnerships (TAPs) throughout the United States. The TAPs help end-users consider CHP, WHP or district energy in their facility, including assisting project development from initial CHP screening to installation. TAPs also provide market opportunity analyses and general education and outreach about CHP benefits to state and local policy makers, regulators, energy end-users, trade associations and others.

DOE supports Industrial Assessment Centers at 24 universities around the country. These centers provide complementary energy audits for small and mid-size manufacturers to identify opportunities to improve productivity, reduce waste, and save energy. IACs typically identify more than $130,000 in potential annual savings opportunities for every manufacturer assessed, nearly $50,000 of which is implemented during the first year following the assessment. The IAC's have conducted over 16,000 assessments since their inception in 1976. A searchable database allows facilities to search recommendations by facility type, recommendations, and assessment center.

Streamlined Air Permitting

CHP installations must comply with a host of federal, state, and local zoning, environmental, health and safety requirements at the site. These include rules on air and water quality, fire prevention, fuel storage, hazardous waste disposal, worker safety and building construction standards. This requires interaction with various agencies including fire districts, air districts, and water districts and planning commissions, many of which may have no previous experience with a CHP project. Air permitting, in particular, can be challenging for CHP projects both in meeting required limits if the benefits of thermal output are not recognized, and in the complexity and time needed for permitting. A number of states have addressed these concerns by instituting permit-by rule for qualifying CHP projects or by streamline the standard permitting process.

Connecticut – Connecticut's distributed generators rule (Sec. 22a-174-42) streamlines the air permitting process for eligible systems that produce both electric and thermal energy. The rule explicitly mentions CHP and any systems that are more than 55 percent efficient, have a nameplate capacity less than 15 MW, a power-to-heat ratio is between 0.15 and 4.0, and that produce fuel for non-emergency use are eligible. The rule provides a thermal credit based on the avoided emissions of the displaced boiler. Eligible systems may operate without applying for or receiving a stand-alone permit.

New Jersey – New Jersey offers two general permits for CHP, one for combustion turbines and another for reciprocating engines. Both permits require participating systems to have total design efficiency greater than or equal to 65 percent. Each includes four different sets of fuel and emission limits, depending on system size and how the source plans to operate the equipment.

Texas – In 2012, Texas established a permit by rule for natural gas CHP systems that meet certain size and performance criteria. The rule applies to NOx and CO emissions from CHP systems. The streamlined process expedites permitting for natural gas-fired CHP systems that are less than 15 MW and where thermal output is more than 20 percent of the total energy output. The compliance calculation accounts for the thermal output of CHP units by converting the measured steam output (Btu) to an equivalent electrical output (MWh) through the "equivalence approach." Credit is given at the rate of 1.0 MWh for each 3.4 million Btu of heat recovered. Notably, gas-fired CHP systems are subject to less demanding requirements than standard power generation limits. For systems less than or equal to 8 MW, NOx emissions are limited to 1 lb/MWh and CO emissions are limited to 9 lb/MWh. NOx limits are more demanding for larger systems (between 8 and 15 MW). Such systems are limited to 0.7 lb/MWh. The streamlining has had a significant impact on permitting. As an example, the Texas PBR allowed a CHP system to obtain an air permit in just 4 to 6 weeks. Prior to PBR, the average time was typically over a year.

Output-Based Emission Standards

Lack of recognition of CHP's efficiency benefits in environmental regulations can be a particular issue in permitting. Higher efficiency generally means lower fuel consumption and lower emissions of all pollutants. Nevertheless, most U.S. environmental regulations have historically established emission limits based on heat input (lb/MMBtu) or exhaust concentration (parts per million [ppm]). These input-based limits do not recognize or encourage the higher efficiency offered by CHP. Nor do they account for the pollution prevention benefits of efficiency in ways that encourage the application of more efficient on-site generation. Moreover, since CHP generates both electricity and thermal energy on-site, it can potentially increase on-site emissions even while it reduces the total overall emissions throughout the air shed. One approach to address these issues is through the use of output-based regulations, which set emission limits based on the total useful energy output (including both thermal and electric) that a system produces (e.g., lbs/MWh). Recent Clean Air Act rules have been written as output-based standards. Many states are likewise adopting output-based standards. Such standards acknowledge that the additional useful energy output was generated in a manner generally cleaner than the separate generation of electricity and thermal energy. CHP systems fare well under this approach because it credits both the thermal and electric energy they produce. This can encourage additional deployment.

California – In September 2007, the California Resources Board amended its Distributed Generation Certification Regulation, which specifies the emissions regulations that particular generators are subject to. Applicable to distributed generation units manufactured after January 1, 2003, the amended rule indicates that CHP units that meet a minimum efficiency requirement may take a thermal credit against their emissions for NOx, CO VOCS and PM, equivalent to 1 MWh per 3.4 million Btus. To be eligible, CHP systems must perform at greater than 60-percent efficiency (high-heating value).

Connecticut – In 2005, Connecticut's Distributed Generators Rule established output-based emissions limits (lb/MWh) for NOX, PM, CO, and CO_2 from small, distributed generation systems that are less than 15 MW in capacity, including CHP systems. The rule allows a CHP system to account for its secondary thermal output using the avoided emissions approach. A CHP system can take into account the secondary thermal output if at least 20 percent of the fuel's total recovered energy is thermal and at least 13 percent is electric, with a resulting power-to-heat ratio between 4.0 and 0.15. The design system efficiency must be at least 55 percent.

Delaware – Delaware has output-based emissions regulations for NOx, PM, CO and CO_2 from eligible generators (Delaware Regulation No. 1144: Control of Stationary Generator Emissions). Qualifying systems must be at least 55 percent efficient and at least 20 percent of the fuel's total recovered energy must be thermal and 13 percent electric (corresponding to an allowed power-to-heat ratio between 4.0 and 0.15). Systems that satisfy these requirements receive a thermal credit based upon the emissions that would have been created by separate generation of the thermal energy (i.e., the "avoided emissions approach"). Under this approach, credit is calculated for CHP systems using the following formula: Credit (lbs/MWh emissions) = boiler limit (lbs per MMBtu)/boiler efficiency x 3.413/power to heat ratio.

Texas – In 2001, Texas adopted a standard permit to facilitate CHP deployment for systems under 10 MW. The permit relies on an output-based standard to measure NOx emissions. As noted above, Texas adopted a permit by rule process for CHP in 2012 that likewise relies on an output-based standard. A CHP system can take into account the secondary thermal output if the heat recovered equals at least 20 percent of the total heat energy output of the CHP system.

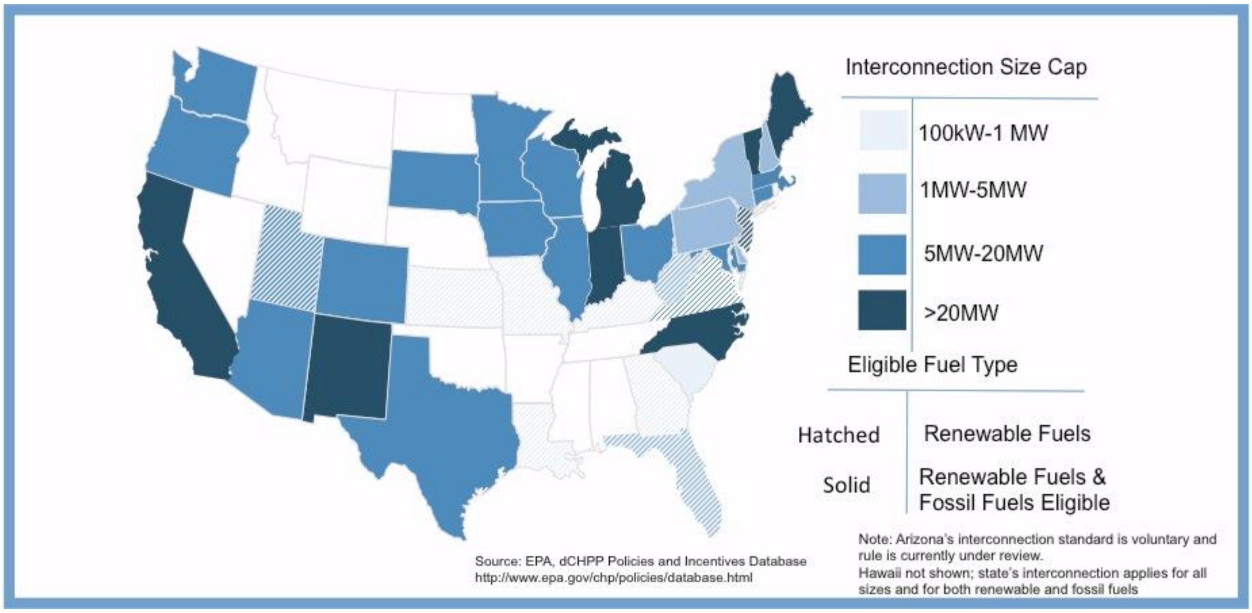
Interconnection Rules

Facilities with CHP systems usually require supplemental and/or standby/back-up service from the utility to provide power needs over and above the output of the CHP system and during periods when the system is down due to routine maintenance or unplanned outages. Interconnection rules detail the technical requirements and procedural process by which an electric-generating unit is connected to the grid. These standards are needed to ensure that both the end-user and the utility's reliability and safety needs are taken into account. A key to CHP's ultimate market success is the ability to safely, reliably, and economically interconnect with the utility grid system. The current lack of standard uniformity in interconnection rules makes it difficult for equipment manufacturers to design and produce modular packages, and reduces the economic incentives for on-site generation. Predictable interconnection rules based on industry technical standards and application processes that limit financial uncertainty and delays can encourage CHP projects. To date, PUCs in more than 40 states have developed interconnection rules that extend to CHP systems; however, these rules vary considerably from one state to another. (Figure A-1). Some are limited to renewably fueled CHP. Others allow interconnection for only a subset of smaller projects (e.g., up to 100 kW), while some encourage deployment by streamlining interconnection for projects up to 10 MW. States may also want to consider the impacts of regional coordination of interconnection procedures to standardize practices.

Considerations to Ensure Consistent Interconnection Rules[28]

1. Interconnection fees commensurate with system size,
2. Streamlined procedures with simple decision-tree screens (allowing faster application processing for smaller systems),
3. Practical technical requirements (often based on existing technical standards));
4. Standardized, simplified application forms and contracts;
5. A dispute resolution procedure to resolve disagreements;
6. The ability for larger (20 MW and larger) CHP systems to qualify; and
7. The ability for on-site generators to interconnect to both radial and network grids.

Figure A-1. States with Standardized Interconnection Processes



California – California was among the first states to establish a standard interconnection policy for distributed generation. Approved in 2000, Rule 21 applies to CHP and other distributed generation systems up to 10 MW. It has been adopted as a model by all three major investor-owned utilities, and follows the established technical guidelines of the IEEE 1547 interconnection standard. In September 2012, the California Public Utilities Commission enacted several major changes to Rule 21 for the first time since 2000. Changes include a "fast track" application process for systems that meet certain size standards, as well as several detailed study options for larger facilities.

Illinois – In August 2007, Illinois enacted legislation (S.B. 680) requiring the Illinois Commerce Commission (ICC) to establish standards for net metering and interconnection for renewable energy systems by April 1, 2008. Although S.B. 680 only requires the promulgation of interconnection standards for "eligible renewable generating equipment," the ICC developed

[28] SEE Action, 2013, "Guide to the Successful Implementation of State Combined Heat and Power Policies," at xi and 13-17 (https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf) (hereinafter "SEE Action 2013").

four tiers of interconnection standards for all distributed generation up to 10 megawatts (MW). The ICC is also considering legislation that would explicitly address CHP. Final interconnection standards were adopted by the ICC in August 2008. In March 2010, the ICC established interconnection standards for Large Distributed Generation Facilities, or those over 10 MW.

Maryland – In June 2008, the Maryland PSC adopted interconnection standards that include CHP up to 10MW and applies to both fossil-fueled and renewable- fueled systems. The rule applies to all types of utilities and has four tiers to determine the level of technical screens, review procedures, and timelines based on the size and type of equipment. Standardize interconnection agreements are available on the PSC renewable portfolio website for all levels of interconnection agreement.

Michigan – Michigan's interconnection standard (Case # U-1375) delineates five separate tiers of interconnection, and covers systems of all sizes with the largest interconnection tier for systems 2 MW systems and above. Both fossil-fueled and renewably fueled CHP systems are eligible for standardized interconnection. However, utilities are the final arbiters of which types of systems and sizes are suitable for their distribution systems. Fees for interconnection range from $75 to $500, depending on system size, and liability insurance is required for systems that are larger than 150 kW.

New Hampshire – The New Hampshire Public Utilities Commission (PUC) established standardized interconnection rules for net-metered systems up to 1 MW in January 2001. Systems that connect to the grid using inverters that meet IEEE 1547 and UL 1741 safety standards do not require an external disconnect device. While utilities cannot require customers to purchase or maintain property insurance or comprehensive personal liability insurance, the customer-generator assumes all risks and consequences associated with the absence of a switch. Utilities may not require customer-generators to perform additional tests, or pay for additional interconnection-related charges. The New Hampshire standards apply to natural gas-fired CHP (in addition to renewable fuels), though CHP can only contribute up to 4 MW under the aggregate net-metering capacity limit of 50 MW. The rule further sets efficiency requirements for eligible CHP systems (greater than 80 percent for systems less than 30 kW and 65 percent for systems between 30 kW and 1 MW).

Washington – The Washington Utilities and Transportation Commission has adopted interconnection standards for distributed generation systems, including CHP (regardless of fuel type), up to 20 MW in size. The standards apply to the state's investor-owned electric utilities, but not to municipal utilities or electric cooperatives. Two separate tiers for interconnection exist; the first tier applies to systems smaller than 300 kW. The second tier applies to systems between 300 kW and 20 MW, and generally follows the interconnection standards promulgated by the Federal Energy Regulatory Commission (FERC).

Standby Rates

Facilities with CHP systems usually require supplemental and/or standby/back-up service from the utility to provide power needs over and above the output of the CHP system and during periods when the system is down due to routine maintenance or unplanned outages. Electric utilities often assess specific standby charges to cover the additional costs the utilities incur as they continue to provide generating, transmission, or distribution capacity (depending on the structure of the utility) to supply backup power when requested (sometimes on short notice).

These fees vary widely by state, region, and utility; however, they are generally designed to cover: (1) backup power that may be needed during an unplanned generator outage, (2) maintenance power during scheduled repairs, (3) supplemental power for customers whose onsite power does not meet all of their energy needs, (4) economic replacement power in the event that grid power costs less than onsite generation, and (5) a transmission and distribution charge to provide electricity in any of these circumstances.[29] The level of these charges is often a point of contention between the utility and the consumer, and can, without proper oversight, create unintended and important barriers to CHP.

Utility rates may consider allocating the total cost of service for a utility to recover costs from customer classes, reflecting each class's use of the system. This principle of "cost causation" is implemented through rate designs that allocate cost based on measurable customer characteristics. Demand charges are often higher than actual costs because of the use of "ratchets," meaning the utility continues to apply some percentage (often as high as 100 percent) of the customer's highest peak demand in a single billing month up to a year after its occurrence. The use of ratchets can be controversial, as some view them as increasing the equity of fixed-cost allocation, while others view them as barriers to economic applications by CHP customer. Although demand ratchets may be appropriate for recovering the cost of delivery, they arguably do not reflect cost causation for shared distribution and transmission facilities.

While rates can act as a deterrent to installing new CHP systems, these charges are needed to allow utilities to recover costs they incur to provide supplemental, backup, and maintenance services. Below are some considerations such that utilities may recover appropriate fixed costs without deterring projects.

Considerations to Establish Rates that Recognize the Potential Benefits of Natural Gas CHP to Electric and Natural Gas Systems[30]

1. Utilities and PUCs may adopt an "as-used" demand charge to reflect the actual cost a CHP system places on the utility, rather than basing fees on prices during peak demand.
2. Utilities may allow CHP customers to purchase all of their backup power at market prices.
3. Generation, transmission, and distribution charges can be unbundled to provide transparency to customers and enable appropriate and cost-based standby rate design
4. Avoidance of demand ratchets. Instead, customer-generators may pay for non-dedicated distribution facilities only when they are actually purchasing backup or maintenance power in a particular month.

Connecticut – The Connecticut Department of Environmental Protection (DEEP) is developing a pilot program to promote CHP by limiting the demand charge electric companies impose on qualifying systems (between 0.5 and 5 MW). Projects selected to participate in the pilot program shall not be required to pay the demand charges pursuant to the distribution demand-ratchet

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[29] *Id.* at 7-11.

[30] Regulatory Assistance Project, 2014, "Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States" (http://www.raponline.org/document/download/id/7020); *see also* SEE Action 2013, at 11.

provision of firm service due to an outage of service of such project. If the project experiences an outage longer than 3 hours, the demand charge must be based on daily demand pricing pro-rated from standard monthly rates. The cumulative capacity for projects participating in the program is limited to 20 MW and eligible projects can continue the terms of the pilot program for 10 years.

Georgia (Georgia Power) – Georgia Power provides a standby rate that incorporates many of the best practices noted above. Customers can contract for either firm or interruptible standby capacity to replace onsite generation when the system is not in service. Customers must provide notification to the utility within 24 hours of taking firm backup power. In the event of an unplanned outage, customers must provide notice to Georgia Power within 30 minutes of beginning service. Scheduled maintenance service (for planned outages) must be scheduled 14 days in advance. Maintenance power is available as firm service during the off-peak months and as interruptible service during peak months. Customers may also purchase supplemental power (i.e., to augment what is produced onsite) at the same rates as other customers. While there are no ratchets, demand charges are subject to a "standby demand adjustment factor," which adjusts the billed standby demand once a customer uses backup service for more than 876 hours during the most recent 12-month period. This provides an incentive for a customer to use standby service as efficiently as possible.

New York – In 2001, the New York Public Service Commission established guidelines for utilities requiring that investor-owned utilities in New York make their standby rates reflective of actual costs. In the guidelines, the PSC states that "Cost based standby delivery rates should provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of DG [distributed generation]."

ConEdison's standby tariff is entirely demand based and does not employ a ratchet. Under guidelines established by the New York Public Services Commission, ConEdison's standby rates reflect a cost-based rate based on the cost of providing delivery service to meet the customer's maximum demand for delivery service at a given time. The company assesses a demand charge based on the actual demand recorded each day, with rates varying by season and time of day—peak versus off-peak. Standby rates do not apply to customers whose on-site generation capacity is less than 15 percent of their maximum demand.

Oregon (Portland General Electric) – Portland General Electric's (PGE) standby tariff is attractive because it does not employ a ratchet, but instead applies an as-used on-peak demand charge to CHP systems. Under this approach, an assumed outage only affects the demand charge in the month that the outage occurs and does not reduce the electric savings from the CHP system in other months. The PGE approach includes several features that support on-site generation:

- Transmission, distribution and generation charges are separated, and within these categories, the rates are further unbundled, thus increasing transparency.
- This rate does not have a demand ratchet so outages do not have an exaggerated effect on the cost.
- The fixed standby demand charges impose only a modest cost when compared to the savings provided by a CHP system.

Creating Markets

At 83 gigawatts nationwide, CHP deployment falls far short of its technical potential. States can adopt policies to signal hosts and developers that these projects are desirable and that they represent a key part of the state's long-term economic and environmental strategy.

States can help create a market for clean and efficient electricity through:

- **State portfolio standards** that require utilities to obtain a certain amount of the electricity they sell from specified sources (including CHP or waste heat to power) and/or achieve specified reductions in electricity consumption.
- Requiring consideration of CHP when **critical infrastructure** is built or renovated.
- Policies that **ease restrictions on electricity sales** from CHP systems.
- **Feed-in tariffs** that guarantee a minimum return for surplus electricity.
- State policies allowing for the **remuneration for excess electricity generated** by CHP units to be made available on the local electric grid.
- **Clean-power purchasing commitments** challenging the state to lead by example and deploy a set amount of clean or renewable power.

State Portfolio Standards

Many states have developed portfolio standards to increase the adoption of renewable energy generation, energy efficiency, and other clean energy technologies. (Figure A-2). Portfolio standards require utilities and retail energy suppliers (mostly electricity and sometimes gas) to procure a certain minimum quantity of eligible energy (typically from renewable sources and other specified supply-side resources) or achieve a minimum amount of energy efficiency savings (typically from demand-side efficiency measures, but these could include CHP).

Portfolio standards can stimulate market and technology development to help clean energy sources become economically competitive with conventional forms of electric power. In this way, portfolio standards can help overcome barriers and create demand for such sources, enabling states to capture their energy-saving, environmental, and economic benefits. Recognizing CHP as an eligible technology benefits utilities by expanding the options that they can use to achieve the standard.

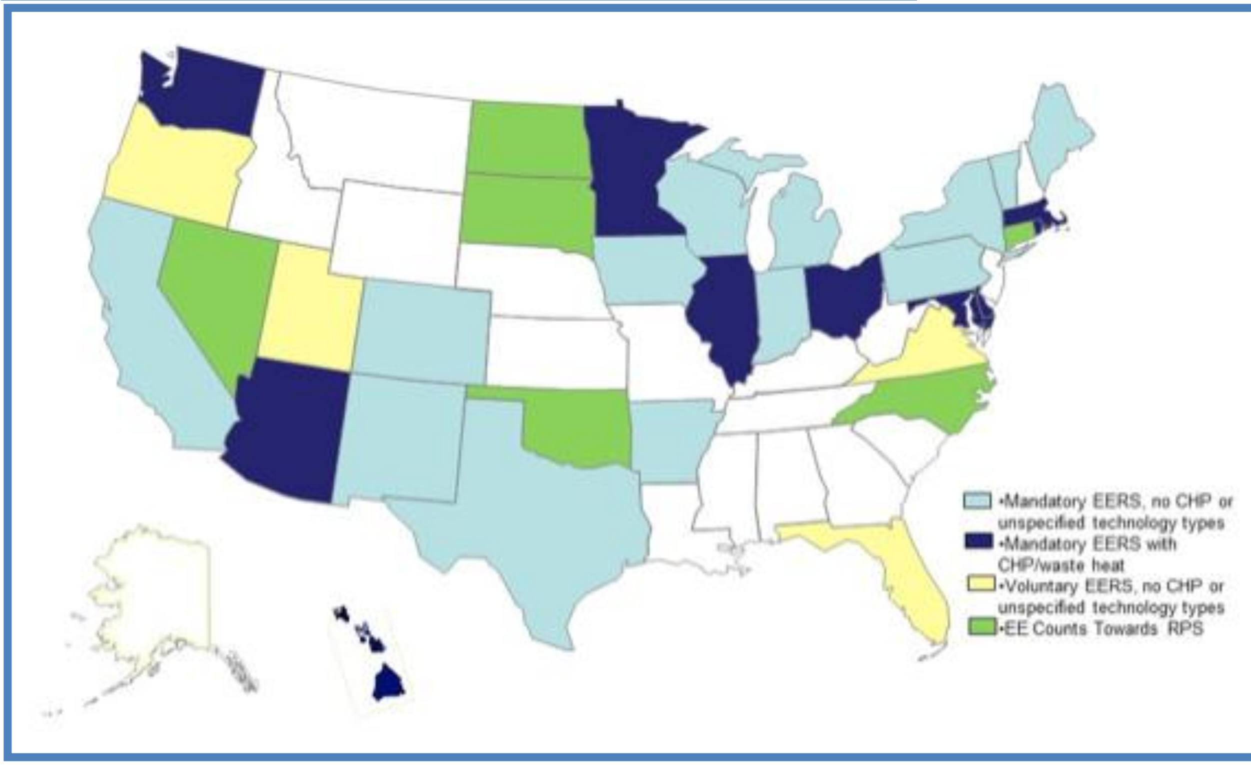
Considerations for CHP in EERS[31]

1. Explicitly identify CHP and/ or waste heat to power (WHP) as an eligible technology in state portfolio standards (RPS or EERS),
2. Provide consistent terminology and definitions for CHP and WHP,
3. Establish a reasonable minimum efficiency threshold to ensure energy savings without excluding certain systems,

[31] SEE Action 2013, at 31-26.

4. Set separate and distinct targets for CHP within the Standard to encourage diversity of supply, and
5. Utilize appropriate calculations to credit the appropriate output (electric and thermal) from a CHP system.

Figure A-2. States with EERS Program for CHP or Waste Heat to Power[32]



Arizona – Renewable Energy Standard**:** In 2006, the ACC approved the Renewable Energy Standard and Tariff (REST), which requires 25 percent of covered utilities' electricity to come from renewable sources by 2025. The standard specifically includes renewably fueled CHP as an eligible resource (i.e., systems fueled with biomass or biogas). Both the electric and thermal outputs of CHP systems are credited. The thermal output from CHP is credited at a conversion rate of 3,415 Btus = 1 Renewable Energy Certificate (REC), and electricity from CHP is credited at a conversion of 1 kWh = 1 REC.

Energy Efficiency Resource Standard**:** On December 18, 2009 the ACC ordered that all investor-owned utilities and rural electric cooperatives achieve 1.25 percent annual savings as a percent of the retail energy sales in the prior calendar year, ramping up to 2 percent beginning in 2014. By 2020, the state should reach 20 percent cumulative savings, plus up to a 2 percent credit for peak demand reductions from demand response programs, for a total standard of 22 percent. Utilities can count energy supply from CHP systems that do not qualify under the state's Renewable Energy Standards towards the standard.

[32] EPA, Feb. 2015, "Portfolio Standards and the Promotion of Combined Heat and Power," at 8 (http://www.epa.gov/chp/documents/ps_paper.pdf).

Massachusetts – In 2009, the Massachusetts Department of Energy Resources established an Alternative Energy Portfolio Standard (APS) (per Senate Bill 2768). The APS requires that 5 percent of a supplier's (both regulated distribution utilities and competitive suppliers) retail sales must come from alternative energy sources by December 31, 2020. An alternative energy source is defined as one that generates electricity using CHP (regardless of fuel type), gasification with capture and permanent sequestration of carbon dioxide, flywheel energy storage, paper-derived fuel sources, or energy-efficient steam technology. The vast majority of this requirement has been met through CHP. This requirement is distinct from the state RPS. CHP and other eligible projects can receive credits, referred to as "APS Alternative Energy Certificates (AECs)," for 1 MWh of electrical energy output or for thermal output (using a conversion factor of 3,412 thousand Btus = 1 MWh). The AECs "earned by a CHP Unit represent the energy saved (in MWh) by operating the Unit as a CHP Unit as compared to separately operating an on-site thermal plant while drawing electricity from the grid" (i.e., the alternative emissions approach).

The Energy Efficiency First Fuel Requirement requires electric and gas utilities to prioritize cost-effective energy efficiency and demand reduction resources over supply resources and orders utilities to submit three-year plans outlining how they will meet the requirement. Demand side resources include energy efficiency, load management, demand response and generation that is located behind a customer's meter including a CHP system with an annual efficiency of 60 percent or greater, with the goal of 80 percent annual efficiency for CHP systems by 2020. The 3-year plans established a statewide electricity savings target of 2.4 percent in the year 2012. A separate goal associated with the Energy Efficiency Resource Standard (EERS) rebate program (also known as the Mass Save program) created a savings target of 25 percent of electric load by the year 2020 with demand side resources. All CHP systems are eligible for the Mass Save program, which establishes three tiers of incentives for utility customers who are considering energy-efficiency upgrades in conjunction with a CHP system.

Washington – Washington's Renewable Energy Standard requires that all types of electric utilities that serve more than 25,000 customers in the state generate 15 percent of their electric load from new renewables by the year 2020 and to undertake all cost-effective energy conservation, including CHP. Of Washington's 62 utilities, 17 are considered qualifying utilities, representing about 84 percent of Washington's load. High-efficiency CHP, owned and used by a retail electric customer to meet its own needs may be counted toward conservation targets. Thermal energy from CHP is credited at a conversion of 3.413 Btus per kWh. One REC = 1 MWh. Distributed generation (DG), defined as a "generation facility or any integrated cluster of such facilities" with a capacity of <5 MW, may be counted as double the facility's electrical output if the utility owns the facility, has contracted for the distributed generation and the associated Renewable Energy Certificate (RECs), or has contracted to purchase only the associated RECs." Renewably fueled CHP systems smaller than 5 MW are eligible under the RPS. Fossil-fueled CHP systems are eligible as a conservation measure. High-efficiency CHP units must have a useful thermal output above 33 percent.

Critical Infrastructure

Because many CHP systems can function in island mode, they can remain operational during extreme weather events, which may compromise the electric grid. This capability makes CHP particularly desirable for critical infrastructure. Critical infrastructure refers to facilities that, if incapacitated, would have a substantial negative impact on national or regional security, economic operations, or public health and safety. These applications include hospitals, water and wastewater treatment facilities, financial institutions, police and security services, and places of refuge (e.g., universities, government buildings, convention centers, sports arenas and hotels).

CHP systems have many advantages over back-up generators.[33] First, CHP systems tend to be more reliable because they are designed for continuous operation rather than emergency use. While generators are only tested periodically, CHP systems are more likely to be properly maintained and operated by trained staff. During the blackout of 1993, half of New York's 58 metropolitan hospitals had failures in their backup generators. The lack of electricity allowed 145-million gallons of raw sewage to be released from a Manhattan pumping station. Even when functioning properly, back-up generators only provide electricity; whereas, CHP provides thermal needs (heating, cooling, chilled water) as well. Finally, back-up generators run of diesel, while the vast majority of CHP systems run on natural gas, greatly reducing their emissions.

These reliability benefits have been demonstrated during a number of extreme weather events. While 8.5-million residents in New Jersey, New York, and Connecticut lost power and heat during Hurricane Sandy, facilities with CHP systems kept their electricity on and heat flowing. A notable example is South Oaks Hospital on Long Island, a 350,000 square foot facility that includes an acute psychiatric hospital, a nursing home, and an assisted living center. During the storm and its aftermath, the hospital maintained full power through the use of its 1.3-megawatt CHP system. Hurricane Sandy is not the only instance when CHP has demonstrated resiliency. In 1994, Mississippi Baptist Medical Center in Jackson, MS, chose to install a 4.3-megawatt CHP system. Eleven years later, during Hurricane Katrina, the 646-bed hospital was the only hospital in the Jackson area to remain 100 percent operational during and after the storm. These resiliency benefits have led several states to adopt policies that encourage greater deployment.

New York – In 2014, New York adopted the Community Risk and Resiliency Act, which adopts many of the recommendations issued by Governor Cuomo's NYS 2100 Commission, the purpose of which was to develop more resilient infrastructure systems in the wake of Hurricane Sandy. The NYS 2100 Commission recommended evaluating combined heat and power and distributed generation projects to improve resiliency of the grid. The act also requires the New York Department of Environmental Conservation and the New York Department of State to provide guidance to help communities implement the act, including the use of resiliency measures.

Texas – In the wake of several major natural disasters that disabled the grid for extended periods, Texas law (Energy Security Technologies for Critical Government Facilities) requires all government entities to identify government-owned buildings and facilities that are critical in an

[33] ICF, 2013, "Combined Heat and Power: Enabling Energy Resilient Infrastructure for Critical Facilities" (http://www.harc.edu/sites/default/files/documents/projects/CHP%20Critical%20Facilities.pdf).

emergency situation and to obtain a feasibility study to consider the technical opportunities and economic value of implementing CHP. Subsequent law (Texas HB 1864) requires this assessment to consider whether the expected energy savings associated with such a system would exceed the costs of the system. This requirement extends to critical facilities that are operational 6,000 hours per year with a peak electric load exceeding 500 kW. The analysis should be based on a potential CHP system with greater than 60 percent efficiency that can provide 100 percent of a facility's critical electricity needs and sustain emergency operations for at least 14 days.

Easing of Restrictions on Electricity Sales

The definition of contiguous property may restrict the sale of excess electricity generated by a CHP facility host to a nearby end-user. Under most current regulatory policies, entities that sell power across public easements are deemed regulated utilities. As a consequence, the sale of electricity by on-site generation, such as CHP is – as a practical matter – restricted to end-users on the host's property or contiguous property. Expanding the definition of what is considered contiguous property to include end-users who take thermal energy from a CHP host provides the host with a potential revenue stream from the sales of electricity.

New Jersey – The New Jersey Cogeneration Bill of 2009 allows CHP systems to "wheel power" to their district energy thermal customers, regardless of whether they are separated by an easement, a street, another building, or a utility-owned right-of-way. New Jersey law defines the CHP facility and its thermal customers as "contiguous." This expanded definition creates a much larger market for electricity from CHP systems, without converting CHP hosts to regulated utilities. The legislation also allows the CHP host to use existing electricity distribution infrastructure at the standard prevailing tariff rate, which is important for enabling district energy systems with CHP.

Texas – HB 2049, which was signed into law in June 2013, clarifies language in the Texas Utility Code to allow CHP facilities to sell electricity and heat to any customer located near the CHP facility. Previously, CHP facilities could only sell electricity to one customer—the electricity service provider. Enactment of HB 2049 opens the market for selling electricity, and thereby has the potential to facilitate the adoption of CHP, particularly for plants that are interested in selling excess CHP power.

Feed-in Tariffs

When CHP systems are optimally sized to match the thermal load of a facility, they may produce excess electricity that cannot be used on-site. Feed-in-tariffs (FIT) allow CHP generators to execute standard-offer contracts to sell electricity to utilities at a fixed rate for an extended period. This provides greater investor certainty for CHP projects and improves the competitive position of CHP in the market by providing an additional revenue stream for projects with excess power capability. While not very prevalent in the U.S., FITs are used in Europe both for renewable and clean distributed generation (including CHP). FITs generally establish a cap on total on-site generation capacity, to create a market for surplus electricity from systems designed for maximizing efficiency without allowing large power projects optimized for power output. FITs can be tied to the current price of natural gas and pay CHP owners at a rate slightly above the market rate for excess electricity, with a gradual decrease in payment over time. This reduces the cost these systems place on the utility as the host recoups its investment. FIT prices may be set high enough to attract the types and amounts of generation desired, while protecting consumers from paying more than needed to achieve generation targets.

Considerations for Feed-in Tariffs and CHP[34]

1. FIT payments may be tied to the current price of avoided fuel and set sufficiently high to allow for an attractive return on investment for CHP owners.
2. Contracts may be set for a long enough period to provide investor confidence.
3. Tariffs may account for environmental, social, and grid-reliability benefits of CHP systems.[7]

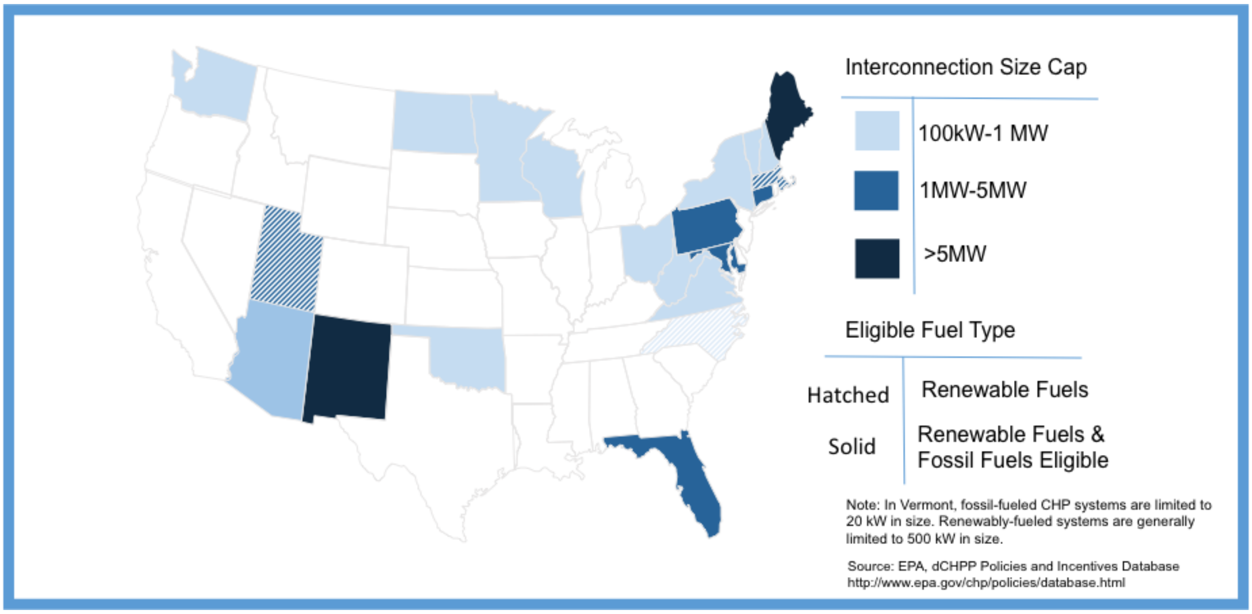
California – In 2006, the state legislature directed the California Public Utilities Commission (CPUC) to have investor owned utilities establish appropriate tariffs for sale of excess power from CHP systems up to 20 MW (AB 1613). In 2008, the CPUC approved three standard-form contracts for purchasing excess electricity from CHP systems of varying sizes: (1) a standard contract for systems with a capacity up to 20 MW; (2) a simplified contract for systems that export no more than 5 MW; and (3) a further simplified contract for systems with a capacity of less than 500 kW. The contract terms are for up to 10 years, with fixed purchase rates throughout the contract term based on the costs of a new combined–cycle gas turbine operating as a baseload resources. Additional compensation is provided for CHP systems located in grid-constrained areas to encourage distributed generation to help avoid grid-system failure. Qualifying systems must be in operation after January 2008, have NOx emissions less than 0.07 lb/MWh, and operate at or above 62 percent total efficiency.

Net Metering

A CHP system's efficiency benefits are maximized when it is sized to match the thermal load. When the thermal load at the site is large, the system may produce surplus electricity. Under wholesale net-metering policies, customers install a second meter on their property, which tracks the on-site generated electricity exported to the grid and utilities remunerate customers for net excess generation at the utility's wholesale avoided cost rate. Such policies provide an additional financial incentive for larger systems and helping those projects pencil out. Where net metering is prohibited, electricity cannot be returned to the grid, and CHP hosts and developers may undersize their systems – foregoing potential economic and environmental benefits. While 43 states have adopted net-metering laws, CHP is only eligible for net metering in a fraction (16) of these states. (Figure A-3). Even where net-metering for CHP is allowed, stringent size caps may prevent systems from realizing their full potential. Moreover, net-metering fees may create additional costs for the CHP system owner and discourage deployment. CHP installations require a significant up-front investment. Net-metering rules reduce the payback period for those systems by allowing owners to generate revenue. This allows owners to make long-term investments with confidence.

[34] SEE Action 2013, at 20-30.

Figure A-3. States with CHP Net-Metering Policies



Considerations for Net-Metering and CHP Deployment[35]

1. Explicitly recognize CHP as an eligible net-metering technology,
2. Increase the size cap on eligible CHP projects to greater than 2 megawatts,
3. Allow system owners to roll over net-metering credits from year to year, and
4. Eliminate burdensome fees.

Maryland – Maryland's net-metering law has been expanded several times since it was originally enacted in 1997. In their current form, the rules apply to all investor-owned utilities (IOUs), electric cooperatives and municipal utilities. Residents, businesses, schools or government entities with systems that generate electricity from micro-CHP (less than 30 kW in capacity) are eligible for net metering, regardless of fuel type. The law permits outright ownership by the customer-generators as well as third-party ownership structures (e.g., leases and power purchase agreements). The provisions allowing for micro-CHP systems (H.B. 1057) and certain third-party ownership structures (S.B. 981) have been in effect since July 2009. In 2011 the law was expanded to require utilities to develop a standard tariff for net metering (S.B. 380). Net metering is available statewide until the aggregate capacity of all net-metered systems reaches 1,500 MW (~8 percent of peak demand). Net excess generation (NEG) is generally carried over as a kWh credit at the retail rate, for 12 months. Compensation for any NEG remaining in a customer's account after a 12-month period is paid to the customer at the commodity energy supply rate.

[35] American Council for an Energy-Efficient Economy, "Net Metering" (http://aceee.org/topics/net-metering) (visited Mar. 16, 2015); International Renewable Energy Council and The Vote Solar Initiative, 2013, "Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures," at 12 (http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf).

Minnesota – Minnesota's net-metering law, enacted in 1983 and expanded in 2013,[36] applies to all investor-owned utilities, municipal utilities and electric cooperatives. Today, all "qualifying facilities" up to 100 kW in capacity under the federal Public Utility Regulatory Policy Act of 1978 (PURPA) are eligible. There is no limit on statewide capacity, though IOUs may request a cumulative generation limit once generation has reached 4 percent of annual retail electricity sales. For smaller systems (up to 40 kW), each utility must compensate customers for customer net excess generation (NEG) at the "average retail utility energy rate," defined as "the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales." This rate is basically the same as a utility's retail rate. Larger systems (40-100 kW) can be compensated at either an avoided-cost rate or as a kWh credit. Both fossil-fueled and renewably fueled CHP systems are eligible for net-metering.

New Hampshire - The New Hampshire Public Utility Commission amended its net-metering rules in 2012 to include CHP systems up to 1 megawatt. Though the rules vary slightly for each customer-type and size, they include several features that benefit CHP. CHP may account for a maximum of 4 MW of the state’s 50 MW aggregate net-metering limit. This allows CHP hosts to size their systems to match their thermal load and sell surplus electricity back to the grid. Eligible CHP systems must meet an efficiency requirement (65-80 percent, depending upon system size). Any customer’s net excess generation during a billing cycle is credited to the customer’s next bill and carried forward indefinitely. At the end of a 12-month period, customers may choose to receive payment for any excess generation at the utility’s avoided-cost rate. Both fossil-fueled and renewably fueled CHP systems are eligible for net-metering. Each utility’s net-metering tariff must be identical, with respect to rates, rate structure and charges, to the tariff that under which the customer would otherwise take default service from the utility.

Washington - Washington's net-metering law, originally enacted in 1998, applies to systems up to 100 kilowatts (kW) in capacity. All customer classes are eligible, and all utilities—including municipal utilities and electric cooperatives—must offer net metering. Net metering is available on a first-come, first-served basis until the cumulative generating capacity of net-metered systems equals 0.25 percent of a utility’s peak demand during 1996. This limit increased to 0.5 percent on January 1, 2014. Both fossil-fueled and renewably fueled CHP systems are eligible for net metering.

Power Purchase Agreements

Power Purchase Agreements (PPA) provide the host customer power (and heat) at a discounted rate, with no capital requirement. A third-party investor and/or developer owns and operates the CHP system and enters into a long-term power contract with the host. PPAs offer a number of benefits to CHP hosts: because they do not require any up-front cost or capital, they can be cash-flow positive from day one, they offer predictable energy pricing and serve as a hedge against electricity prices, they reduce system performance or operating risks, and do not have maintenance costs.

[36] Note that many of the features described here will not take effect until rules are enacted for H.F. 729 at the PUC. Pending those changes, net metering is limited to systems up to 40 kW in size.

Connecticut – Connecticut Natural Gas and Southern Connecticut Gas have designed and tested a zero-capital program, which was designed to help spur third-party CHP ownership with customers interested in on-site CHP. The program would encourage five or ten year power purchase agreements (PPAs) between customers and the third-party developers and owners. Under this model, CNG/SCG's parent UIL would be able to enjoy the benefits of CHP on its electric system without having to own the CHP systems, which it is not permitted to do under current market rules. CNG/SCG also explored developing an unregulated subsidiary that could legally own these generation assets.

Utility Participation in CHP Markets

A key policy option for increasing installed CHP capacity may be to allow incumbent natural gas and electric utilities to participate in CHP markets. Utility participation may take many forms. A utility could own CHP facilities directly on the customer side of the meter, provide packages of services to customers who own their own CHP, or it could incorporate combined heat and power solutions into ratepayer-funded efficiency programs. Today, utilities are constrained in the provision of CHP services. Most do not have the regulatory approval to build and own CHP facilities – nor do most have the flexibility to negotiate custom service packages for customers who own their own CHP systems. This represents a significant barrier to the growth of cost-effective CHP because incumbent utilities are uniquely positioned to facilitate new CHP development. Utilities understand CHP technology, which has been present in the market about as long as central station power supply. They generally are very familiar with their customers' process needs and concerns. Utilities may be in a unique role to assume the risk and responsibility of installing and maintaining a complex energy system so that the customer can concentrate on its primary mission or business. They may also be able to accept longer paybacks and lower internal rates of return than their customers. Direct support could involve investments in equipment and infrastructure over a long investment horizon – a proposition that aligns with the utility business model.

Pennsylvania (Philadelphia Gas Works) – Understanding that the up-front costs of CHP can be a hurdle to market development, Philadelphia Gas Works (PGW), the municipal gas utility in Philadelphia, works with commercial and industrial customers on a case-by-case basis to provide an incentive in an amount up to the up-front capital cost for small and mid-size CHP systems (70 kW to 7 MW to date), recovering those costs plus PGW's cost of capital over the first five years of CHP system operation through the facility's gas bills. The facility signs a service agreement that reflects the total PGW incentive, but the five-year through-the-bill cost recovery eliminates the site's need for upfront capital. After PGW cost recovery, the customer enjoys the benefits of ongoing energy savings during the remaining lifetime of the CHP equipment.

New Jersey (New Jersey Natural Gas) – New Jersey Natural Gas (NJNG) has a Fostering Environmental and Economic Development (FEED) program (Sheets 94-96) designed to provide financial assistance for energy-efficiency upgrades and economic development opportunities for commercial and industrial customers. FEED provides access to investment capital, incentives, and/or discounted rates to encourage the installation of energy-efficient equipment, including CHP projects, as well as business growth, expansion, and retention in the state. Up-front project funding is provided by NJNG with the principal and interest repaid by the customer over an agreed upon period of time. Long-term, fixed-price contracts for the purchase of natural gas are also available under FEED. This program provides no risk to ratepayers and no associated costs will be recovered through NJNG's rates.

Missouri – Utility involvement can include joint ownership of CHP assets, as is the case with Missouri Ethanol LLC in Laddonia, MO, a 45-million-gallon per year ethanol plant that began operation in September 2006. It is one of two ethanol plants in the state that employ gas turbine-based CHP through a utility-ethanol plant partnership. The CHP system is jointly owned by Missouri Ethanol and the Missouri Joint Municipal Electric Utility Commission (MJMEUC), a statewide joint action agency that supplies power and capacity services to 56 municipal Missouri utilities. The Missouri Ethanol project is patterned after an earlier CHP partnership between the City of Macon, MO, and the Northeast Missouri Grain LLC ethanol plant in Macon. In both Macon and Laddonia, the utilities own and are responsible for gas turbine operation. However, the ethanol plants own and are responsible for the heat-recovery equipment, including the HRSGs and downstream steam systems. Natural gas costs are shared between the utilities and ethanol plants in both cases. The Missouri Public Utility Alliance (MPUA) views the Laddonia project as a "win-win-win" effort, as it provides a cost-competitive power supply for MJMEUC, reduced steam costs for the ethanol plant, and additional baseload gas demand for the Missouri Municipal Gas Commission.

California – Southern California Gas Company has proposed a Distributed Energy Resources Services Tariff as a fully elective, optional tariff service under which SoCalGas would design, construct, own, operate, and/or maintain CHP equipment on or adjacent to customer properties. The service would be available to all SoCalGas customers. All project costs would be recovered from the tariff customer, with no subsidy from or business risk borne by other ratepayers. Although equipment is positioned on or adjacent to the customer's property, the equipment is owned and/or maintained by the utility. Tariff customers will pay a negotiated service fee that captures, at a minimum, the full system cost, including both capital and O&M over the contract term. Agreement to provide service is at SoCalGas' discretion and will depend on non-discriminatory factors such as safety, system capacity, SoCalGas resource availability, technical feasibility, and acceptability of commercial terms.

State Level Legislation and Regulation

Examples of State Legislation and Regulations		
State	**Title/Description**	**URL Address**
Alabama	AlabamaSAVES Revolving Loan Fund Program: The loans may be used to purchase and install equipment for renewable-energy systems and energy-efficient fixtures and retrofits installed on property owned and/or operated by an eligible businesses. CHP is considered an eligible technology under this program, with loans ranging from $50,000 to $4-million.	http://bit.ly/1Oc2zpM
Arizona	Renewable Energy Standard: ACC approved the Renewable Energy Standard and Tariff (REST), which requires 25% of covered utilities' electricity to come from renewable sources by 2025. The standard specifically includes renewably fueled CHP as an eligible resource (i.e., systems fueled with biomass or biogas)	http://www.azcc.gov/divisions/utilities/electric/res.pdf?d=756
Arizona	Energy Efficiency Resource Standard: Utilities can count energy from CHP systems that do not qualify under the state's Renewable Energy Standards towards the standard.	http://images.edocket.azcc.gov/docketpdf/0000116125.pdf?d=52
Arizona	Southwest Gas Smarter Greener Better Distributed Generation program: Offers its customers rebates ranging from $400 to $500 per kilowatt of installed CHP capacity. Eligible CHP systems must achieve a total system efficiency of 60% to 70% or higher.	http://www.swgasliving.com/rebates/arizona/arizona-smarter-greener-better%C2%AE-distributed-generation-program-business
California	CaliforniaFIRST: The program allows property owners to finance the installation of energy and water improvements and pay the amount back on their property tax bill.	https://commercial.californiafirst.org/overview
California	Self-Generation Incentive Program: Provides incentives to renewably fueled and fossil-fueled CHP systems. The maximum incentive is $5 million with a minimum 40% customer investment. Eligible system size is capped at 3 MW and must meet a 60% minimum efficiency.	http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/index.htm

California	CPUC Feed-in-Tariff: FIT authorized for CHP systems up to 20 MW to execute a standard-offer contract to export energy to one of the state's largest three IOUs. The payment rate is fixed for the duration of the generator's contract, which ranges from 10 to 20 years, depending on the owners' discretion.	http://www.cpuc.ca.gov/PUC/energy/CHP/feed-in+tariff.htm
California	Discounted Natural Gas Rates: Natural gas utilities can provide natural gas to qualified cogeneration systems under the same distribution rates offered to large electric utilities.	ftp://ftp2.cpuc.ca.gov/LegacyCPUCDecisionsAndResolutions/Resolutions/G2738_19871016_AL1422G.pdf
California	Distributed Generation Certification Regulation: Amended its Distributed Generation Certification Regulation (Senate Bill 1298), which specifies the emissions regulations that particular generators are subject to. Applicable to distributed generation units.	http://www.arb.ca.gov/energy/dg/2006regulation.pdf
California	Standard Interconnection Agreement: Applies to CHP and other distributed generation systems up to 10 MW. It has been adopted as a model by all three major investor-owned utilities, and follows the established technical guidelines of the IEEE 1547 interconnection standard.	http://www.cpuc.ca.gov/PUC/energy/rule21.htm
California	Distributed Energy Resources Services Tariff: Southern California Gas Company has proposed a fully elective, optional tariff service under which SoCalGas would design, construct, own, operate, and/or maintain CHP equipment on or adjacent to customer properties. All project costs would be recovered from the tariff customer, with no subsidy from or business risk borne by other ratepayers.	http://www.socalgas.com/regulatory/A1408007.shtml
Connecticut	Low-Interest Loans: Support the installation of customer-side distributed resources (including CHP systems larger than 50 kW). The minimum loan size is $1,000,000 for a program total of $150-million.	http://www.cga.ct.gov/2011/pub/chap283.htm#Sec16-243j.htm
Connecticut	Microgrid Grant & Loan Program: Supports distributed energy generation at critical facilities.	http://www.ct.gov/deep/cwp/view.asp?a=4120&Q=508780
Connecticut	C-PACE: Allows commercial, industrial or multi-family property owners to access 100% upfront, long term financing for energy efficiency and clean energy improvements on their properties through a special assessment on the property tax bill, which is repaid over a period of years (up to 20 years).	http://www.cpace.com/

Connecticut	Streamlined Permitting: Streamlines the permitting process for eligible systems that produce both electric and thermal energy. The rule explicitly mentions CHP and any systems that are more than 55% efficient, have a nameplate capacity less than 15 MW, a power-to-heat ratio between 0.15 and 4.0, and that produce fuel for non-emergency use are eligible.	http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/sec42.pdf
Connecticut	Standby Rate Ruling: Developing a pilot program to promote CHP by limiting the demand charge electric companies impose on qualifying systems (between 0.5 and 5 MW).	http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=1
Connecticut	Property Tax Exemption: Municipalities are authorized, but not required, to offer a property tax exemption lasting up to 15 years for qualifying CHP systems.	http://www.cga.ct.gov/2011/pub/chap203.htm#Sec12-81.htm
Connecticut	Integrated Resource Plan: In 2014, the Connecticut Department of Energy and Environmental Protection (DEEP) released a draft Integrated Resource Plan proposing to offer incentives of up to $450/ kWh for up to 160 MW of new CHP capacity in the state. The incentives will decline over time, as the state's deployment goals are met.	http://www.ct.gov/deep/lib/deep/energy/irp/2014_irp_draft.pdf
Connecticut	Power Purchase Agreement: Connecticut Natural Gas and Southern Connecticut Gas have designed and tested a zero-capital program, which was designed to help spur third-party CHP owners with customers interested in on-site CHP. The program would encourage five or ten year power purchase agreements (PPAs) between customers and the third-party developers and owners.	https://www.cngcorp.com/wps/wcm/connect/42bbd20048ea0c62b80ef980657d4c17/06-LGS+%28Large+General+Service%29.pdf?MOD=AJPERES&CACHEID=42bbd20048ea0c62b80ef980657d4c17
Delaware	Output Based Emissions Regulations: Qualifying systems must be at least 55% efficient and at least 20% of the fuel's total recovered energy must be thermal and 13% electric (corresponding to an allowed power-to-heat ratio between 4.0 and 0.15).	http://www.dnrec.state.de.us/air/aqm_page/docs/pdf/Final Regulation 1144.pdf

Georgia	Georgia Power Standby Rate: Customers can contract for either firm or interruptible standby capacity to replace onsite generation when the system is not in service. Customers must provide notification to the utility within 24 hours of taking firm backup power. Maintenance power is available as firm service during the off-peak months and as interruptible service during peak months. Customers may also purchase supplemental power (i.e., to augment what is produced onsite) at the same rates as other customers. While there are no ratchets, demand charges are subject to a "standby demand adjustment factor," which adjusts the billed standby demand once a customer uses backup service for more than 876 hours during the most recent 12-month period. This provides an incentive for a customer to use standby service as efficiently as possible.	http://www.georgiapower.com/pricing/files/rates-and-schedules/12.30_BU-8.pdf
Hawaii	Green Infrastructure Bonds: To help developers of clean-energy installations (including CHP) on commercial or residential properties secure low-cost financing.	http://www.capitol.hawaii.gov/session2013/bills/SB1087_CD1_.htm
Illinois	Cash Incentives for CHP: Up to $2 million, for individual CHP projects in Illinois public sector facilities.	http://www.illinois.gov/dceo/whyillinois/KeyIndustries/Energy/Pages/CHPprogram.aspx
Illinois	Standard Interconnection Agreement: Established standards for net-metering and interconnection for renewable energy systems since 2008. Although S.B. 680 only requires the promulgation of interconnection standards for "eligible renewable generating equipment," the ICC developed four tiers of interconnection standards for all distributed generation up to 10 MW.	http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=095-0420&GA=095
Maryland	Standard Interconnection Agreement: Maryland PSC adopted interconnection standards that include CHP up to 10 MW and applies to both fossil-fueled and renewably fueled systems.	http://www.dsd.state.md.us/comar/SubtitleSearch.aspx?search=20.50.09
Maryland	BGE Smart Energy Savers Program: This program provides incentives to industrial and commercial customers who install efficient (>65% high-heating value) CHP systems.	http://www.bgesmartenergy.com/business/CHP

Maryland	Net-Metering Rule: Expanded several times since enactment in 1997. Applies to all utilities. Residents, businesses, schools or government entities with systems that generate electricity using micro-CHP (less than 30 kW in capacity) are eligible for net metering. Net excess generation (NEG) is generally carried over as a kWh credit at the retail rate, for 12 months.	http://www.dsd.state.md.us/comar/SubtitleSearch.aspx?search=20.50.10
Massachusetts	Energy Efficiency First Fuel Requirement: Electric and gas utilities to prioritize cost-effective energy efficiency and demand reduction resources. Demand side resources include energy efficiency, load management, demand response and generation that is located behind a customer's meter including a CHP system with an annual efficiency of 60% or greater, with the goal of 80% annual efficiency for CHP systems by 2020.	https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter25/Section21
Massachusetts	Alternative Energy Portfolio Standard: The APS requires that 5% of a supplier's (both regulated distribution utilities and competitive suppliers) retail sales must come from alternative energy sources by December 31, 2020. An alternative energy source is defined as one that generates electricity using CHP (regardless of fuel type), gasification with capture and permanent sequestration of carbon dioxide, flywheel energy storage, paper-derived fuel sources, or energy-efficient steam technology.	http://www.mass.gov/eea/docs/doer/rps/rps-225-cmr16-mar-12-2009.pdf
Massachusetts	Mass Save: This program was created implement the Green Communities Act of 2008, which recognizes CHP as an energy-efficiency measure eligible for utility incentives. The incentives are tiered (ranging from $750 to $1,200), with large incentives (covering up to 50% of installed costs) given to the most efficient systems.	http://www.masssave.com/business/eligible-equipment/combined-heat-and-power
Michigan	Property Assessed Clean Energy (PACE) financing: For commercial and industrial property owners for energy efficiency and/or renewable energy projects, including CHP, that range in size from $10,000 to $350,000.	http://a2energy.org/commercial-savings
Michigan	Standard Interconnection Agreement: Delineates five separate tiers of interconnection, and covers systems of all sizes with the largest interconnection tier for systems 2 MW systems and above. Both fossil-fueled and renewably fueled CHP systems are eligible for standardized interconnection.	http://efile.mpsc.state.mi.us/efile/docs/15787/0046.pdf

Minnesota	Net-Metering Rule: Enacted in 1983 and expanded in 2013, applies to all utility types. All "qualifying facilities" up to 100 kW in capacity are eligible. There is no limit on statewide capacity, though IOUs may request a cumulative generation limit once generation has reached 4% of annual retail electricity sales.	https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B84622862-F00D-499A-B116-30F78862AD40%7D&documentTitle=20127-77081-01%22
Minnesota	University of Minnesota CHP Bonds: $10 million, of $64.1 million, is being dedicated to a CHP project, designed to replace current coal furnaces.	http://discover.umn.edu/news/politics-governance/session-successes-position-university-minnesota-advance-research-and
Missouri	Missouri Ethanol LLC and MJMEUC CHP Partnership: Missouri Ethanol LLC in Laddonia, MO, a 45-million-gallon per year ethanol plant that began operation in September 2006. It is one of two ethanol plants in the state that employ gas turbine-based CHP through a utility-ethanol plant partnership. The CHP system is jointly owned by Missouri Ethanol and the Missouri Joint Municipal Electric Utility Commission (MJMEUC), a statewide joint action agency that supplies power and capacity services to 56 municipal Missouri utilities.	http://www.districtenergy.org/pdfs/DEMagArticles/2Q07/WebLink2q07.pdf
New Hampshire	Output Based Emissions Regulations: Cap SO2, NOx, CO2 and mercury emissions on older power plants. These regulations use output-based methods to measure emissions and impact several power plants that were in existence prior to the legislation. CHP is not directly mentioned in the regulations, and specific allocations describing how thermal output would be credited are not listed in detail.	http://www.gencourt.state.nh.us/rsa/html/nhtoc/NHTOC-X-125-O.htm
New Hampshire	Standard Interconnection Agreement: Established standardized interconnection rules for net-metered systems up to 1 MW in January 2001. Systems that connect to the grid using inverters that meet IEEE 1547 and UL 1741 safety standards do not require an external disconnect device.	http://www.puc.state.nh.us/Regulatory/Rules/Puc300.PDF
New Hampshire	Net-Metering Rule: Amended existing rule in 2012 to include CHP systems up to 1 MW. CHP may account for a maximum of 4 MW of the state's 50 MW aggregate net-metering limit.	http://www.puc.state.nh.us/Regulatory/Rules/PUC900.pdf

New Jersey	Streamlined Permitting: Offers a general permit for CHP combustion turbines and reciprocating engines. Units with total design efficiency greater than or equal to 65% are eligible.	http://www.state.nj.us/dep/aqpp/downloads/general/GP-021.pdf.
New Jersey	Energy Resilience Bank: Invest in long-term recovery strategies focused on critical facilities and enhancing energy resilience.	http://www.njeda.com/web/pdf/ERBProgramGuide.pdf
New Jersey	Sales & Use Tax Exemption: Applies to the purchase of natural gas and utility service for on-site cogeneration facilities.	http://www.districtenergy.org/assets/pdfs/2010CampConf/New-Jersey-Cogeneration-Bill-12.3.09.pdf
New Jersey	New Jersey Cogeneration Bill of 2009: Allows CHP systems to “wheel power” to their district energy thermal customers, regardless of whether they are separated by an easement, a street, another building, or a utility-owned right-of-way	http://www.districtenergy.org/assets/pdfs/2010CampConf/New-Jersey-Cogeneration-Bill-12.3.09.pdf
New Jersey	Fostering Environmental and Economic Development: Designed to provide financial assistance for energy-efficiency upgrades and economic development opportunities for commercial and industrial customers. FEED provides access to investment capital, incentives, and/or discounted rates to encourage the installation of energy-efficient equipment, including CHP projects, as well as business growth, expansion, and retention in the state.	http://www.njng.com/regulatory/pdf/Tariff03012015.pdf
New York	Discounted Natural Gas Rates: Customers using natural gas for distributed generation including CHP have been able to qualify for discounted natural gas delivery rates.	http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B3CD9E19C-22C1-4749-9E1F-E78260350465%7D
New York	Flex Tech Program: Provides New York State industrial, commercial, institutional, government, and nonprofits with technical assistance to help them make “informed energy decisions.”	http://www.nyserda.ny.gov/All-Programs/Programs/FlexTech-Program
New York	ConEdison Standby Tariff: Tariff is entirely demand based and they do not employ a ratchet. Standby rates do not apply to customers whose on-site generation capacity is less than 15% of their maximum demand.	http://www.coned.com/dg/service_categories/standby.asp
New York	Standby Rate Ruling: Established guidelines for utilities requiring that investor-owned utilities make their standby rates reflective of actual costs.	http://www.utilityregulation.com/content/orders/01NYdoc10690.pdf

New York	CHP Accelerator Program: This program is sponsored by NYSERDA and provides incentives for the installation of pre-qualified, pre-engineered CHP systems by pre-approved CHP system installers.	http://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities/PON-2568-CHP-Acceleration-Program.aspx
New York	Community Risk and Resiliency Act: The NYS 2100 Commission recommended evaluation CHP and distributed generation projects to improve grid resiliency. The act also requires the New York Department of Environmental Conservation and the New York Department of State to provide guidance to help communities implement the act, including the use of resiliency measures.	http://assembly.state.ny.us/leg/?default_fld=&bn=A06558&term=2013&Summary=Y&Actions=Y&Memo=Y&Text=Y
New Mexico	Energy Efficiency and Renewable Energy Bonding Act: Authorizes up to $20 million in bonds, backed by the state's Gross Receipts Tax, to be issued to finance energy efficiency and renewable energy improvements in state government and school buildings.	http://www.emnrd.state.nm.us/ECMD/CleanEnergyTaxIncentives/CREB.html
New Mexico	CHP Tax Credit: Offers a 6% tax credit for qualifying clean-energy projects, including "recycled energy".	http://www.tax.newmexico.gov/Tax-Professionals/tax-credits-overview.aspx
North Carolina	CHP Tax Credit: Equal to 35% of the cost of eligible renewable energy property (including CHP fueled by non-renewable fuels) placed into service.	http://www.dor.state.nc.us/downloads/nc478g_instructions.pdf
Ohio	Ohio Air Quality Improvement Tax Incentives Act: Provides a 100% exemption from the tangible personal property tax (on property purchased as part of an air quality project), real property tax (on real property comprising an air quality project), a portion of the corporate franchise tax (under the net worth base calculation), and sales and use tax (on the personal property purchased specifically for the air quality project only) for outstanding bonds issued by OAQDA.	http://www.ohioairquality.org/clean_air/default.asp
Ohio	CHP Tax Exemption: May provide a 100% sales and use tax exemption for certain tangible personal property for industrial and commercial property owners.	http://development.ohio.gov/bs/bs_contaxexempt.htm

Oregon	Standby Rate Ruling: Portland General Electric's (PGE) standby tariff is attractive because it does not employ a ratchet, but instead applies an as-used, on-peak demand charge to CHP systems. Under this approach, an assumed outage only affects the demand charge in the month that the outage occurs and does not reduce the electric savings from the CHP system in other months.	https://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_200.pdf
Pennsylvania	Discounted Natural Gas Rates: Philadelphia Gas Works (PGW) offers discounted gas rates for commercial and industrial customers who use natural gas in any combination of cooling, heating, and power production.	http://www.pgworks.com/business/fueling-the-future/combined-heat-power
Pennsylvania	Philadelphia Gas Works CHP Up-Front Capital Financing: Understanding that the up-front costs of CHP can be a hurdle to market development, Philadelphia Gas Works (PGW), the municipal gas utility in Philadelphia, works with commercial and industrial customers on a case-by-case basis to provide an incentive in an amount up to the up-front capital cost for small and mid-size CHP systems (70 kW to 7 MW to date), recovering those costs plus PGW's cost of capital over the first five years of CHP system operation through the facility's gas bills. The facility signs a service agreement that reflects the total PGW incentive, but the five-year through-the-bill cost recovery eliminates the site's need for upfront capital. After PGW cost recovery, the customer enjoys the benefits of ongoing energy savings during the remaining lifetime of the CHP equipment.	http://www.pgworks.com/business/customer-care/large-business
Texas	Streamlined Permitting: Developed a streamlined air permitting process for NOx and CO emissions from CHP systems (following passage of authorizing legislation in 2011). The streamlined process expedites permitting for natural gas-fired CHP systems that are less than 15 MW and where thermal output is more than 20% of the total energy output.	http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/segu_final.pdf
Texas	Output Based Emissions Regulations: Adopted a standard permit to facilitate CHP deployment for systems under 10 MW. The permit relies on an output-based standard to measure NOx emissions. In 2011, Texas adopted a more robust streamlined permitting process, which likewise relies on an output-based standard.	http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/segu_final.pdf

Texas	Energy Security Technologies for Critical Government Facilities: Requires all government entities to identify critical government-owned buildings and facilities and to obtain a feasibility study to consider the technical opportunities and economic value of implementing CHP.	http://www.statutes.legis.state.tx.us/Docs/GV/htm/GV.2311.htm
Texas	House Bill 2049: Signed in June 2013, clarifies language in the Texas Utility Code to allow CHP facilities to sell electricity and heat to any customer located near the CHP facility.	http://www.legis.state.tx.us/tlodocs/83R/billtext/pdf/HB02049I.pdf
Washington	Standard Interconnection Agreement: For distributed generation systems, including CHP (regardless of fuel type), up to 20 MW in size. The standards apply to the state's investor-owned electric utilities, but not to municipal utilities or electric cooperatives.	http://apps.leg.wa.gov/WAC/default.aspx?cite=480-108
Washington	Renewable Energy Standard: Utilities must generate 15% of their electric load from new renewables by 2020 and to undertake all cost-effective energy conservation, including CHP. High-efficiency CHP, owned and used by a retail electric customer to meet its own needs may be counted toward conservation targets.	http://www.secstate.wa.gov/elections/initiatives/text/i937.pdf

Appendix B

Enforceability of CHP Programs under the Clean Power Plan

Introduction

The Clean Air Act (CAA) embraces a model of cooperative federalism, with a shared set of responsibilities between federal and state governments. For over 40 years, states have filed implementation plans to achieve air quality standards and other objectives set forth by Congress in the 1970, 1977 and 1990 Clean Air Act Amendments. In what is now a familiar pattern, the U.S. EPA sets an overall goal and states develop plans to achieve the goal. States will develop plans following criteria set out in the statute or EPA guidelines. This same pattern will apply to compliance plans that states will develop to control CO_2 emissions from power plants under the Clean Power Plan (CPP)[37] and section §111(d) of the CAA.[38] But there are differences between the requirements for §111(d) compliance plans, relative to those applicable to state implementation plans developed under section §110 of the CAA. Section §111(d) plans are subject to fewer limitations.

The CPP lays out a set of four general criteria by which EPA will approve or disapprove state compliance plans, along with a list of 12 components that each plan must contain. Most of the criteria and plan elements are self-explanatory and relatively uncontroversial. But one of the criteria ("enforceability") has generated some confusion and heightened attention – partly because it exists at the boundaries between state and federal authority, and between private and governmental responsibilities under the CAA. In this Appendix we address the "Enforceability" criteria, as described in the proposed CPP.

Enforceability comes up in several contexts. In approving a state plan EPA must find that the provisions of the plan are enforceable by some entity or entities. There are two aspects to this. First the state must have authority to enforce its plan. The enforceability criteria can be satisfied in a variety of ways including interagency agreements, contract provisions or state regulatory requirements. Second, and more controversial, is the requirement that some parts of the plan need to be federally enforceable, that is by EPA, or – in some limited cases – by citizen suits.

It is important to note that states are likely to have the option to adopt one of several approaches to compliance including "Portfolio", "EGU", "State Commitment", or "Complementary Measures" approaches.[39] Under each approach, states will be able to utilize a variety of measures to demonstrate how they will achieve their emissions targets and meet the "enforceability" criteria for state plan approval – without making each individual measure subject to federal enforcement.[40] These approaches will be less resource-intensive for state

[37] EPA published proposed rules to control CO_2 emissions from fossil fired power plants at 79 Fed. Reg. 34830 (June 18, 2014).

[38] 42 USC §7411(d).

[39] Different analysts have described the various approaches in different ways – some specific approaches highlighted in this categorization have been considered sub-options to the "portfolio" or "state commitment" approaches by others.

[40] States are more likely to succeed at incentivizing private entities to invest in cost-effective CHP projects if they can structure the relevant parts of their compliance plans to eliminate any perceived risk of federal enforcement or citizen suits against the CHP owner or industrial participant in a state or utility IEE program.

regulators and more likely to incentivize voluntary actions – such as investment in CHP – to help the state achieve its emission goal more cost effectively.

General Criteria for State Plan Approval

- Enforceability
- Performance
  – Projected and actual achievement of emissions goal established by EPA
- Measurable
  – Quantifiable & Verifiable
- Accountability
  – A process to report on plan Implementation, emissions, outcomes, and corrective measures

We discuss here various options by which a CHP module in a state's CPP compliance plan can satisfy the enforceability requirement. In general, we conclude that EPA is very unlikely to disapprove a CHP component of a state plan due to concerns about enforceability.[41] This is because of the wide degree of flexibility afforded to states in formulating compliance plans under §111(d) and the Proposed CPP rule, and because EPA and the Obama Administration clearly favor energy efficiency as a compliance option, and have set ambitious goals for CHP development.[42] Moreover, as a practical matter, the agency will have its hands full to respond to states that refuse to file compliance plans or whose plans are clearly deficient. By contrast, states that make a good faith effort to include CHP in their plans are likely to receive deference and approval from the agency. Keys to EPA approval of §111(d) plans are to: 1) make reasonable assumptions about the performance of the CHP elements of the plan; 2) identify who is responsible for any state incentive programs designed to generate emission reductions or credits from CHP; 3) rely on established EM&V protocols; and, 4) include correction or contingency mechanisms if projected IEE/CHP strategies underperform.

Statutory Requirements

A plan under §111(d) must, "provide for the implementation and enforcement of the standards of performance" established by EPA,[43] – meaning each state's goal for reducing CO_2 emissions from its fleet of affected EGUs. As states approach the task of compliance planning under §111(d), we reiterate that the concept of enforceability is different for state compliance plans under §111(d) than it is for state implementation plans to meet ambient air quality standards for criteria pollutants (under §110 of the Clean Air Act). This conclusion is based on the language of the CAA which states that the EPA Administrator shall establish a procedure "similar" to that used by states to submit implementation plans to achieve ambient air quality standards under §110.[44] "Similar" by definition is not "identical," and EPA clearly has discretion to use a different definition for §111(d) plan enforceability than has historically been applied to state

[41] CHP components in this context are measures or programs designed to promote the deployment of un-affected CHP projects to reduce demand, and emissions, from affected EGUs. Note that certain existing CHP projects are classified as affected EGUs and subject to the requirements of the Clean Power Plan.
[42] Executive Order, Accelerating Investment in Industrial Energy Efficiency, August 30, 2012. See https://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency.
[43] 42 USC §7411(d)(1)(B).
[44] 42 USC §7411(d)(1).

implementation plans (SIPs) under §110.[45] For this reason, EPA guidance documents and regulations issued pursuant to §110 SIP development are not necessarily applicable to the question of whether a §111(d) compliance plan is adequately enforceable.

Language on Enforceability in the Proposed Rule

Under the proposed CPP, states must establish an emission standard along with implementation and enforcement measures that will achieve a level of emission performance equal to or better than state-specific CO_2 emission performance goals to be established in the final rule.[46] Under guidelines that predate the §111(d) proposal, EPA has explained that: "a requirement that is enforceable as a practical matter is one that is quantifiable, verifiable, straightforward, and calculated over as short a term as reasonable."[47] Those terms are carried over into the proposed rule.

None of these requirements is a challenge for CHP systems, which typically incorporate sophisticated monitoring equipment and for which there are well-established evaluation, measurement and verification standards.

The proposed rule provides states with a series of options for establishing emission standards that will accommodate a diverse range of state approaches. Each state will have significant flexibility to determine how to best achieve its CO_2 goals.[48] Under the proposed rule, states may choose to submit plans that hold the affected EGUs fully and solely responsible for achieving the emission performance level, or to rely in part on measures undertaken by the state itself (or other entities) to achieve part of the required emissions reductions.

In general, the proposal states that all measures relied on to achieve the emission performance level be included in the state plan, and that inclusion in the state plan renders those measures federally enforceable once approved by EPA. But EPA may consider an exception to the rule, under which it could approve state plans that assure a requisite level of emission performance without rendering each of the contributing measures federally enforceable.[49]

[45] For additional discussion of the differences between §110 SIP and §111(d) implementation plans see, Regulatory Assistance Project, Feb. 2015, "It's Not a SIP: Opportunities and Implications for State §111(d) Compliance Planning," available at http://www.raponline.org/document/download/id/7491. This policy brief provides a side-by-side comparison of Sections §110 and §111(d) of the Clean Air Act and highlights the significant differences in requirements for state compliance plans under each section. The authors distinguish between EPA's constrained role in reviewing and approving state plans to ambient air quality standards and the wide flexibility afforded by §111(d). The authors describe opportunities for states to use new approaches to air quality planning due to the unusual flexibility allowed under Section §111(d. States are not confined to the prescriptive federal requirements generally associated with state implementation plans (SIPs). Instead, states can craft their Clean Power Plan compliance to take advantage of complementary state policies, and can tailor their plans to achieve compliance more cost-effectively, meet other state public policy goals, and boost state employment and economic gains—as long as the plan meets EPA's established greenhouse gas emissions reduction targets. The authors suggest several steps states can take to maximize reward and minimize risk when taking innovative approaches to air quality planning under Section §111(d).

[46]79 Fed. Reg. at 34909. ("In developing its plan, a state must ensure that the plan is enforceable and in conformance with the CAA.").

[47] 79 Fed. Reg. at 34909. ("EPA is taking comment on whether the preexisting guidance on enforceability is appropriate for state plans under §111(d) and whether to issue new guidance on this subject.").

[48] 79 Fed. Reg. at 34900.

[49] 79 Fed. Reg. at 34901.

An obligation to reduce or avoid emissions in a state plan is considered enforceable if it:

- Identifies the responsible party or parties,
- Includes a mechanism to demonstrate compliance with the obligation, and
- Provides legally enforceable consequences for non-compliance.[50]

Programs that Meet Enforceability Criteria

There are several ways that states can include CHP projects in their CPP plans in a manner that is consistent with enforceability requirements: [51]

Portfolio Approach – In its June 2014 proposal, EPA proposes to allow states to impose federally enforceable obligations on entities other than the owners and operators of the covered plants as part of what EPA calls a state "portfolio approach." A state plan could combine emission limits on power plants with federally enforceable obligations on the administrator of an energy-efficiency program to deliver a certain amount of emissions reductions or megawatt hours of energy savings. In such a case, a portion of the state goal would be achieved through enforceable obligations on the covered power plants, and the remainder of the obligations would fall on one or more other entities. In a portfolio approach, the state could include CHP measures as part of a diverse set of compliance measures (alongside renewables and other energy efficiency policies, for example) in an overall plan.[52]

Using this approach, the state could estimate anticipated emission rate or tonnage reductions from a CHP program. During the compliance period, energy savings or emission reductions from CHP projects would decrease the need for other, more expensive compliance options. If emission reductions anticipated from CHP programs are less than expected, that shortfall can be made up by increasing reliance on other compliance options (e.g., by shifting dispatch to cleaner units, or increasing energy efficiency incentives). Where CHP projects are included in a state §111(d) plan (as part of a portfolio approach), "enforceability" is ensured by agreements or

[50] 79 Fed. Reg. 34913 ("An emission standard is enforceable if: (1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified, (2) compliance requirements are clearly defined, (3) the affected entities responsible for compliance and liable for violations can be identified, (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability (as discussed in Section VIII.F.1 of this preamble), and the Administrator and the state maintain the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA sections 113(a)–(h).").

[51] The discussion below is adapted based in part from on ideas expressed in Litz & Macedonia, April 2015, "Choosing a Policy Pathway for State §111(d) Plans to Meet State Objectives," though our overall conclusions may be somewhat different. The Litz & Macedonia paper is, available at http://www.betterenergy.org/sites/www.betterenergy.org/files/Pathway_web.pdf.

[52] 79 Fed. Reg. 34901 (In a portfolio approach, "the plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and demand-side EE measures, that reduce CO_2 emissions from affected EGUs. Under this approach, it would be all of the measures combined that would be designed to achieve the required emission performance level for affected EGUs as expressed in the state goal. Under this approach, the emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level. Rather, the state plan would include measures enforceable against other entities that support reduced generation by, and therefore CO_2 emission reductions from, the affected EGUs. As noted, these other measures would be federally enforceable because they would be included in the state plan.")

contracts by which the state provides incentives for the construction and operation of specific CHP projects. Enforceability could also be met where a state creates requirements to install CHP in state facilities via Executive Orders, regulations, and legislation. These provisions would qualify as enforceable measures for purposes of §111(d) compliance. States should use conservative estimates of CHP emission impacts for planning purposes. The CHP *program* would be federally enforceable, but as a practical matter this simply means that if the program underperforms, the state could be required by EPA to revise its implementation plan to secure offsetting emission reductions from other measures.

EGU or Power Plant Owner Approach – Under the EGU approach, the affected EGU owners would be the parties solely obligated to achieve a designated portion of state emissions reduction targets (or an individual target) and subject to enforcement. CHP could be used under this approach if the state were to allow the power plant owner to purchase emission reduction credits from new CHP investments by third parties. Alternatively the utility could co-invest in CHP with its customers with contractual rights to the resulting credits. EGUs purchasing emissions reduction credits from CHP projects could be assured of the validity of those GHG reductions by utilizing transaction safeguards (e.g. contracts or insurance) similar to those used for trading electricity and other commodities.[53]

State Commitment Approach – Under a state commitment approach, a state could assume responsibility for achieving a portion of the state goal without imposing enforceable obligations on entities other than the affected power plants. "The state plan would include a commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs."[54] Some states have requested EPA to allow the state commitment approach, provided that it contains backstop programs that would achieve the emissions goal in the event the state's commitment fails. If EPA were to allow this, a state would need to develop a plan designed to achieve the state commitment, along with a backstop mechanism that would if the state's commitment is not met (e.g., the state would adopt a more ambitious portfolio standard.[55]

State Complementary Measures Approach - This approach is essentially a hybrid of the State Commitment and EGU approaches, except that it avoids the need to make state CHP or IEE programs strictly enforceable by the state or federal governments. EPA sought comments on and is considering an approach that would allow a state plan to rely on measures such as CHP as "complementary policies" that would not be federally enforceable.[56] Under this suggested

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[53] 79 Fed. Reg. at 34902 ("A state plan that imposes a mass limit on affected EGUs that is sufficiently stringent to achieve the emission performance level would not need to include RE or demand-side EE measures as an enforceable component of the plan to assure the achievement of that performance level. The mass limit itself would suffice. However, the state may wish to implement RE and demand-side EE measures as a complement to the plan to support achievement of the mass limit at lesser cost.").

[54] 79 Fed. Reg. at 34902 ("Under the state commitment approach, the state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally enforceable. Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs.").

[55] 79 Fed. Reg. 34830, at 34837.

[56] 79 Fed. Reg. at 34901-2 ("We note that some existing state programs, such as RGGI in the northeastern states, do impose the ultimate responsibility on fossil fuel fired EGUs to achieve the required

approach, the EGU emission limits would be federally enforceable, but renewable energy and demand-side EE measures would serve as complementary measures and would not be enforceable under federal law; instead, they would remain enforceable under state law.

Who Has Enforceable Obligations under the State Plan?

It is important to understand who does *not* have federally enforceable obligations under a §111(d) compliance plan. Companies that voluntarily supply CHP or IEE emission reduction credits are not subject to either state or federal enforcement under the federal Clean Air Act. As voluntary suppliers of emission reduction credits their only obligations are to satisfy the terms of emission-credit sales contracts, or agreements under which they receive financial incentives from state programs.[57]

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emission reductions, but are also designed to work either concurrently, or in an integrated fashion, with RE and demand-side EE programs that reduce the cost of meeting those emission limitations. These existing programs offer a possible precedent for another type of CAA section §111(d) state plan. Such a plan approach could rely on CO_2 emission standards enforceable against affected EGUs—whether in the form of emission rate or mass limits—to ensure achievement of the required emission performance level, but also include enforceable or complementary RE and demand-side EE measures that lower cost and otherwise facilitate EGU emission reductions. Depending on the type of plan, these RE and demand-side EE measures could either be enforceable components of the plan (that is, the states could require affected EGUs or other affected entities to invest in RE or in demand-side EE programs) or be complementary to the plan. In this manner, RE and demand-side EE measures could be a major component of a state's overall strategy for reducing EGU CO2 emissions at a reasonable cost.

In regard to Federal Enforceability, the proposal states (at 79 Fed. Reg. at 34902), "Another concern expressed by some stakeholders is that including RE and demand-side EE measures in state plans would render those measures federally enforceable and thereby extend federal presence into areas that, to date, largely have been the exclusive preserve of the state and, in particular, state public utility commissions and the electric utility companies they regulate. These stakeholders suggest that states could rely on RE and demand-side EE programs as complementary measures to reduce costs for, and otherwise facilitate, EGU emission limits without including those measures in the CAA section §111(d) state plan. Under this suggested approach, the EGU emission limits would be federally enforceable, but RE and demand-side EE measures would serve as complementary measures and would not be enforceable under federal law; instead, they would remain enforceable under state law. According to stakeholders, those types of state programs, particularly because they are well-established, can be expected to achieve their intended results. Thus, they suggest that the states could conclude that those RE and demand-side EE measures would be beneficial in assuring the achievement of the required emission performance level by the affected EGUs specified in the CAA section §111(d) state plan, even without including those measures in the plan.").

[57] This is an important point since industrial, commercial and institutional customers who could become hosts for a CHP facility are unlikely to invest in such systems if they perceive that this would subject them to federal or state enforcement under air quality laws for the resulting emission reduction performance of those systems. CHP systems may need to secure permits to meet conventional air quality controls, but those permits would not include conditions relative to CO_2 control impacts of their facilities unless they are an affected unit under EPA's §111(d) rules. Only very large CHP systems that sell large significant amounts of power into wholesale power markets are affected units under EPA's proposed §111(d) rules. See § 60.5795 of proposed rule.

Implications

The final §111(d) rule will likely contain at least as much compliance and state plan flexibility as was included in the proposed rule. It is equally likely that it will formalize some form of a "state commitment" or "complementary measures" approach that allows states to count emission reductions from CHP programs toward compliance with state targets, without subjecting those programs to federal enforcement. This form of compliance plan is likely to be attractive to many states. Emission targets are federally enforceable under this kind of §111(d) compliance plan – not the particulars of any CHP module. In the following examples we describe likely scenarios for how the enforceability requirement will play out for CHP systems under a final rule that allowed a State Commitment approach:

- A state compliance plan may project that a set of CHP incentives (managed by a state agency or under a utility DSM program) will achieve a certain amount of energy savings or CO_2 tonnage reductions. The state strategy is enforceable because it is based on a series of contractual agreements and EM&V protocols signed by entities that receive incentives or other financial support to invest in CHP. Under a state commitment or "complementary" measures approaches, if a measure's emission reduction estimate is underperforming, neither that state, nor participants in that specific program are subject to federal enforcement. Rather, it is the overall performance of a state plan that is federally enforceable, and if one strategy falls short it may be made up by over-performance from other plan elements, or by corrective measures (e.g., to improve the CHP/IEE strategy, or other elements of the compliance plan) taken in later years of the applicable three-year compliance period.
- A power plant owner may create a standard offer to purchase emission reduction credits from industrial, commercial and institutional customers who invest in CHP systems. Under this approach, the EGU would file a compliance plan with the state that includes a projection of emission reductions from that strategy (which in combination with other elements of the unit's compliance plan will achieve the target assigned to that unit). The power plant owner's plan is enforceable since it is based on a series of contracts with suppliers of emission reduction credits – under which payments will typically be performance based. If the amount of credits secured under this strategy are less than projected, the power plant owner will simply adjust its compliance plan to rely more heavily on other strategies within the three-year averaging window to show compliance with the applicable limit (e.g. by purchasing more emission credits from other forms of energy efficiency or shifting more of its generation to power plants with lower emission rates).

Concluding thoughts on Enforceability with respect to CHP

The enforceability requirements for state plans under §111(d) present no obstacles to use of CHP as a compliance measure for state CO_2 targets. States can promote CHP investments to meet the requirements of the CPP in a variety of ways. While the proposed rule contains some ambiguity, we do not think that it would impose any federally enforceable obligations against CHP hosts. This is unlikely to change in the final rule. As such, we believe that states and EGU owners can begin to develop compliance plans that incorporate CHP with confidence.

Appendix C

Estimating CO_2 Savings from CHP

Introduction

State plans will need to detail how emissions reductions from compliance measures will be quantified and verified. The EGU emission reduction impacts of CHP projects are similar to the emission reduction impacts of other end-use energy efficiency measures. Like other energy efficiency investments, CHP deployed at viable sites like industrial or commercial/institutional facilities (hereinafter “non-affected CHP”) reduces demand – and therefore emissions – from affected EGUs. As such, the methodology used for crediting emission reductions caused by new and up-graded[58] non-affected CHP should be equivalent to the methodology used for crediting other end-use energy efficiency measures. However, unlike end-use efficiency, implementation of CHP often results in incremental fuel use – and incremental CO_2 emissions – at the host facility.

There is ongoing debate that, under section §111(d) of the Clean Air Act, EPA may be constrained to consider only the avoided emissions from the affected EGUs when crediting beyond the fence efficiency measures such as CHP. If so, then the full electricity output of non-affected CHP systems installed at commercial or industrial facilities would be credited in the same manner as any other beyond-the-fence energy-efficiency measure, without regard to the incremental increase in emissions that may result at the facility installing the CHP unit. This approach is consistent with the way a number of states, such as Massachusetts, Connecticut and Maryland have incorporated CHP into their Energy Efficiency Resource Standards (EERS).

There are also a number of policy priorities that support treating non-affected CHP in this manner: well-designed and -operated CHP has been shown to be more efficient than the separate generation of heat and power, leading to significant CO_2 emissions reductions from both greater efficiency and the use of less carbon-intensive fuels; CHP provides significant benefits to local energy infrastructure in terms of grid support, enhanced reliability, and more efficient operation, and increasingly as an approach to enhancing resiliency of critical infrastructure - these benefits are not normally captured in straight energy efficiency calculations; and increased deployment of efficient CHP supports a major goal of the current Administration.[59] Non-affected CHP units are also currently covered by strict standards for criteria pollutants and often subject to efficiency requirements that further ensure they are operating cleanly and efficiently. Under this approach, it may be appropriate to require some minimum performance requirements that non-affected CHP units must meet to ensure there are creditable savings.[60]

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[58] Up-graded CHP units refers to expansion or efficiency improvements to existing CHP systems

[59] Executive Order – Accelerating Investment in Industrial Energy Efficiency, August 30, 2012, http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency

[60] Many state CHP regulations require at least 20 percent of the input fuel’s recovered energy to be thermal and a minimum overall CHP system efficiency of 55 to 60 percent. *See, e.g.,* SEE Action Network, 2013, “Guide to the Successful Implementation of State Combined Heat and Power Policies," https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-

If in the final rule, however, EPA ultimately elects to require a netting of the electricity credits from non-affected CHP units to account for incremental emissions at the industrial or commercial CHP host facility, the credit calculation must be simple, accurate and understandable. CHP's efficiency and emissions benefits derive from the fact that CHP systems produce *both* electricity and useful thermal energy simultaneously from a single fuel source. To appropriately recognize the emissions benefits of CHP, output-based emissions measures can be developed that account for both the electricity and the thermal outputs of the system.[61]

The draft CPP discussed methods for quantifying the impacts of an efficiency policy by measuring energy (MWh) savings and converting those savings into an emissions impact. For CHP, more than one methodology for quantifying emissions savings may be allowable. Energy savings and emissions reductions may be quantified and verified through direct measurement or another technically sound method that is both "reliable and replicable."[62] A state should identify a protocol for verifying electricity savings and associated emissions reductions from CHP that is best suited to its conditions and available resources.

CO_2 Reduction Benefits of CHP

In any approach used to determine the "net" emissions reduction benefits of CHP, the first step is to calculate the incremental emissions that CHP generates at the host site. Table A-1 presents the energy performance and incremental CO_2 site emissions for typical CHP systems. For natural gas CHP, the CHP systems range from a 200 kW microturbine that could be used to provide power and hot water to a commercial application, to a 20 MW gas turbine providing power and steam to a manufacturing facility. For biomass boiler/steam turbine CHP, the systems include a boiler firing wood waste and a boiler firing pulping or "black" liquor.[63] The energy and emissions calculations in the table are based on CHP system performance characteristics from the 2015 edition of the DOE/EPA CHP Technology Catalog[64] for electrical efficiency, power to heat ratio and total CHP efficiency for each system. Values for useful thermal output, CHP fuel use, and total CHP CO_2 emissions are calculated from these performance characteristics based on each system producing 20,000 MWh of net electricity

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heat-and-power-policies or NACAA, May 2015, "Implementing EPA's Clean Power Plan: A Menu of Options", Chapter 3, http://www.4cleanair.org/NACAA_Menu_of_Options

[61] Waste heat to power (WHP) projects have no CO_2 emissions as long as no supplemental fuel is used. Thus, they can be treated as other Building Block 4 activities – the net electricity generation can be simply counted in the same manner as other demand-side efficiency savings.

[62] U.S. EPA, 2012, "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans."

[63] Biomass boiler/steam turbine CHP systems are common within the U.S. forest products industry. Low pressure (~5 bar) and medium pressure (~12 bar) steam is extracted from the turbine and is used in the pulping manufacturing process, and generated electricity is used onsite or sold. Because of the large onsite steam requirements, forest product CHP systems are optimized for steam production and generally produce limited amounts of electricity in relation to steam generation. The most common fuels used within forest product CHP systems are pulping liquors, a by-product of the chemical pulp manufacturing process, and wood waste, though some fossil fuels such as natural gas and coal are used as well. Within the US industrial sector, the pulp and paper and wood products industry comprised nearly 60 percent of the biomass material used in combustion for energy generation. (http://www.eia.gov/totalenergy/data/monthly/pdf/sec10_5.pdf).

[64] DOE/EPA, March 2015, "CHP Technology Catalog."

output. The table also includes a comparison to traditional end-use efficiency measures that result in 20,000 MWh of site electricity savings.

The table includes estimates of displaced thermal fuel and CO_2 emissions for each CHP case based on typical boilers that would have been replaced by the installation of the CHP system. In the case of natural gas CHP, the typical displaced boiler is assumed to be a conventional 80 percent efficient natural gas boiler that would have provided the same useful thermal output as the CHP system (i.e., generating steam on site). For biomass CHP, the displaced boiler is assumed to be a similarly fueled biomass boiler providing the same amount of steam energy to the process and at the same boiler efficiency as the CHP boiler – 65 percent for wood waste and 70 percent for pulping liquor. Incremental CO_2 emissions are then calculated for each CHP system by subtracting the displaced thermal CO_2 emissions from the total CHP CO_2 emissions. For natural gas CHP, incremental emissions range from 5,145 tons of CO_2 for the 1,000 kW reciprocating ("recip") engine CHP system with 78.9 percent total efficiency to 6,761 tons for the 200 kW microturbine system with 69.5 percent total efficiency. Incremental emissions for natural gas can range from 30 to 50 percent of total CHP system emissions. While discussions continue on the appropriate methods to characterize biogenic CO_2[65] emissions resulting from biomass combustion, abundant research has made it clear that for the types of biomass being used in CHP systems in the forest products industry (i.e., black liquor, bark, and other woody residues from manufacturing), it is reasonable to use a biogenic CO_2 emissions factor of zero.[66,67,68,69] Therefore, while biomass boiler/steam turbine CHP will consume additional biomass fuel compared to the steam-only biomass boiler that it replaces, there are no new CO_2 emissions released to the environment associated with either the CHP biomass boiler or the displaced steam-only biomass boiler.[70]

Finally, the table presents the effective CO_2 emissions rate in pounds per MWh for each CHP system. This value is calculated by dividing the incremental CO_2 emissions (in pounds) by the

[65] Biogenic CO_2 emissions are defined as CO_2 emissions related to the natural carbon cycle, as well as those resulting from the production, harvest, combustion, digestion, fermentation, decomposition, and processing of biologically based materials. CO_2 emitted from burning sustainable biomass will not increase total atmospheric CO_2. CO_2 is captured from the atmosphere by plants and trees during their growth, when it is released again during combustion it is reentering the carbon cycle, not being newly created. If plant materials are then regrown over a given period of time, the regrowth of new biomass takes up as much CO_2 as was released from the original biomass through combustion. Debate continues on the precise categorization of biomass resources that would be considered sustainable in regards to the carbon cycle.

[66] US EPA. November 2014. Revised Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources, Appendix D: Feedstock Categorization and Definitions. http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html

[67] Gaudreault, C., Malmberg, B., Upton, B., Miner, R. 2012. "Life cycle greenhouse gases and non-renewable energy benefits of kraft liquor recovery." *Biomass and Bioenergy*. 46:683-692.

[68] Gaudreault, C., Miner, R. 2015. "Temporal aspects in evaluating the greenhouse gas mitigation benefits of using residues from forest products manufacturing facilities for energy production. " *Journal of Industrial Ecology*. (not yet assigned an issue number) http://onlinelibrary.wiley.com/doi/10.1111/jiec.12225/abstract

[69] Lamers, P. 2013. "Sustainable International Bioenergy Trade. Evaluating the impact of sustainability criteria and policy on past and future bioenergy supply and trade." PhD Dissertation Utrecht University.

[70] Small amounts of methane and nitrous oxide, also greenhouse gases, are produced during the combustion of these materials

net electricity generation (20,000 MWh for each system).[71] For natural gas CHP, effective CO_2 emissions rates range from 514 lbs CO_2/MWh for the 1,000 kW recip engine CHP system to 676 lbs CO_2/MWh for the 200 kW microturbine system.[72] The effective emissions rates for the biomass CHP cases and for end-use energy efficiency are all zero lbs CO_2/MWh.

Table C-1. Typical CHP System Performance

System*	200 kW Microturbine CHP	1,000 kW Recip Engine CHP	7,000 kW Gas Turbine CHP	20,000 kW Gas Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	End Use Efficiency
CHP and Displaced Boiler Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Pulping Liquor	Pulping Liquor	N/A
Net Electric Efficiency, %	29.5%	34.5%	28.9%	33.3%	5.9%	6.4%	N/A
Power to Heat Ratio	0.74	0.78	0.70	0.89	0.10	0.10	N/A
Total CHP Efficiency	69.5%	78.9%	70.4%	70.5%	64.6%	69.6%	N/A
Electric Generation, MWh_e	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Thermal Output, MWh_t	27,027	25,641	28,571	22,472	197,979	197,979	0
CHP System Fuel Use, MMBtu	231,322	197,740	236,125	205,233	1,148,595	1,066,552	0
CHP System CO_2 Emissions, tons	13,521	11,558	13,801	11,996	0	0	0
Displaced Boiler Efficiency	80%	80%	80%	80%	65%	70%	N/A
Displaced Boiler Fuel, MMBtu	115,661	109,721	122,490	95,562	1,039,236	965,005	0
Displaced Boiler CO_2 Emissions, tons	6,760	6,413	7,160	5,586	0	0	0
Incremental CO_2 Emissions, tons	6,761	5,145	6,642	6,410	0	0	0
Effective CO_2 Emissions Rate, lbs/MWh	676	514	664	641	0	0	0

*CHP system performance based on DOE/EPA CHP Technology Catalog, March 2015

[71] This approach for calculating the effective CO_2 emissions rate for CHP is based on the "avoided emissions approach" as described later in this Appendix.
[72] As a comparison, the CO_2 emissions rate for average fossil grid generation (eGRID 2012 – 2010 data) is 1,745 lbs/MWh on a national basis, and the CO_2 emissions rate for advanced natural gas combined cycle generation with 50% electrical efficiency is 798 lbs/MWh.

CHP generates reductions in CO_2 emissions from the power sector when the effective emissions rate of the CHP system as calculated in Table C-1 in terms of lbs CO_2/MWh is less than the emissions rate of the electricity that CHP power displaces on the grid. Table 2 presents the potential CO_2 savings for the six CHP systems and traditional energy efficiency measures compared to three sources of central station generation – 1) average fossil generation based on eGRID 2012 (2009 national data), 2) existing natural gas combined cycle generation (NGCC) with a net electric efficiency of 43 percent, and 3) advanced natural gas combined cycle generation (AGCC) with a net electric efficiency of 50 percent. This table is not proposing any of these specific central station generation sources as the baseline for calculating CHP CO_2 reductions under the Clean Power Plan (this issue is discussed in a later section in this Appendix), but is meant to demonstrate that well designed and operated CHP systems provide significant CO_2 emissions reduction benefits compared to a range of fossil-fueled central station power, including advanced natural gas combined cycle generation.

In calculating the potential emissions benefits of CHP (and of traditional end-use efficiency measures), it is important to consider that one MWh of electricity demand reduction at the point of use generally would replace more than one MWh of central station grid generation because of transmission and distribution (T&D) losses in getting power from the power plant to the end-user. The calculations of potential energy and CO_2 emissions savings in Table C-2 are based on national average T&D losses of 6.18 percent (eGRID 2012) – as a result, the 20,000 MWh of net CHP generation or end-use efficiency savings in Table C-1 is equivalent to 21,277 MWh of grid generated electricity. The CO_2 savings in Table C-2 are calculated by subtracting the incremental CO_2 emissions of the CHP systems in Table 1 from the CO_2 emissions of the equivalent grid power (grid emissions in pounds equals displaced power generation (in this case 21,277 MWh) times the grid emissions rate in lbs/MWh).[73]

Compared to average fossil grid generation, the CO_2 savings from 20,000 MWh of <u>natural gas CHP</u> generation ranges from 11,803 tons for the 200 kW microturbine CHP system to 13,401 tons for the 1,000 kW recip engine system, or 64 percent to 72 percent of the total 18,564 tons of CO_2 emissions from equivalent grid power CO_2 savings from 20,000 MWh of natural gas CHP generation ranges from 3,186 tons to 4,802 tons when CHP is compared to existing natural gas combined cycle generation (or 32 to 48 percent of the total 9,947 tons of CO_2 emissions from equivalent NGCC power); and from 1,726 tons to 3,342 tons when natural gas CHP is assumed to be displacing advanced natural gas combined cycle generation (or 20 to 39 percent of the total 8,846 tons of CO_2 emissions from equivalent AGCC power). Since both biomass CHP systems and traditional end-use efficiency measures have effective emissions rates of zero lbs/MWh, all result in CO_2 savings equal to the full emissions levels from the equivalent amount of power generation for each fossil fuel option.

[73] CO_2 savings can also by calculated by multiplying the net generated CHP power (20,000 MWh) times the difference of the displaced grid emissions rate corrected for T&D losses (corrected grid emissions rate corrected = grid emissions rate/(1-%T&D losses) and the effective emissions rate of the CHP system.

Table C-2. Potential Energy Savings and CO_2 Emissions Reductions for Typical CHP Systems Compared to Fossil-Fueled Grid Power

System	200 kW Microturbine CHP	1,000 kW Recip Engine CHP	7,000 kW Gas Turbine CHP	20,000 kW Gas Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	End Use Efficiency
CHP System Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Wood Waste	Pulping Liquor	N/A
Incremental CO_2 Emissions, Tons (Table 1)	6,761	5,145	6,642	6,410	0	0	0
T&D losses, %	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%
Displaced Central Station Power, MWh	21,277	21,277	21,277	21,277	21,277	21,277	21,277
1) Displacing Average Fossil Generation (eGRID 2009 Data)							
Average Fossil Heat Rate, Btu/kWh	9,596	9,596	9,596	9,596	9,596	9,596	9,596
Average Fossil CO_2 Emissions Rate, lbs/MWh	1,745	1,745	1,745	1,745	1,745	1,745	1,745
Displaced Fuel, MMBtu	204,170	204,170	204,170	204,170	204,170	204,170	204,170
Displaced CO_2 Emissions, tons	18,564	18,564	18,564	18,564	18,564	18,564	18,564
Energy Savings, MMBtu	**88,509**	**116,151**	**90,535**	**94,499**	**204,170**	**204,170**	**204,170**
CO_2 Savings, Tons	**11,803**	**13,419**	**11,922**	**12,154**	**18,564**	**18,564**	**18,564**
2) Displacing Current Natural Gas Combined Cycle Generation (43% efficiency)							
NGCC Heat Rate, Btu/kWh	8,000	8,000	8,000	8,000	8,000	8,000	8,000
NGCC CO_2, Emissions Rate, lbs/MWh	935	935	935	935	935	935	935
Displaced NGCC Fuel, MMBtu	170,213	170,213	170,213	170,213	170,213	170,213	170,213
Displaced NGCC CO_2, tons	9,947	9,947	9,947	9,947	9,947	9,947	9,947
Energy Savings, MMBtu	**54,552**	**82,194**	**56,578**	**60,541**	**170,213**	**170,213**	**170,213**
CO_2 Savings, Tons	**3,186**	**4,802**	**3,305**	**3,537**	**9,947**	**9,947**	**9,947**
3) Displacing Advanced Natural Gas Combined Cycle Generation (50% efficiency)							
AGCC Heat Rate, Btu/kWh	6,824	6,824	6,824	6,824	6,824	6,824	6,824
AGCC CO_2, Emissions Rate, lbs/MWh	798	798	798	798	798	798	798
Displaced AGCC Fuel, MMBtu	145,191	145,191	145,191	145,191	145,191	145,191	145,191
Displaced AGCC CO_2, tons	8,486	8,486	8,486	8,486	8,486	8,486	8,486
Energy Savings, MMBtu	**29,530**	**57,173**	**31,557**	**35,520**	**145,191**	**145,191**	**145,191**
CO_2 Savings, Tons	**1,726**	**3,342**	**1,844**	**2,076**	**8,486**	**8,486**	**8,486**

Calculating CO_2 Reduction Credits from CHP

As shown in Tables C-1 and C-2, the level of CO_2 savings delivered by CHP depends on the overall efficiency and ratio of power to thermal output of the CHP system, as well as the emissions characteristics of the grid power that the CHP electric output displaces. CHP clearly provides significant emissions savings compared to average fossil generation which is often used as a first cut estimate of displaced grid power. Beyond this, well designed and properly operated CHP also provides CO_2 emissions savings compared to high efficiency natural gas combined cycle generation, which is often considered the marginal generation resource in many regions. The role CHP can play in each state and the value of the savings that CHP can deliver depend on the emissions rates of affected EGUs in the state and EPA's target emission standard for the state.

An approach to crediting the emissions reductions from CHP is to first calculate the effective emissions rates (as introduced in Table 1) in lbs CO_2/MWh of a CHP project or portfolio of projects. The effective emissions rate calculation essentially incorporates a credit for the thermal output of the CHP system to determine the incremental CO_2 emissions "tied" to the electricity output of the system. Credits under the CPP would be warranted if this effective emissions rate is lower than the current state or utility emissions rate in lbs CO_2/MWh (or lower than the state target rates in the future). The actual amount of CO_2 savings could then be estimated by multiplying the net annual electricity production of the CHP unit (or fleet) by the difference between the appropriate displaced EGU emissions rate and the effective emissions rate or the CHP system (or systems).

Alternatively, the ratio of the effective emissions rate of the CHP system or fleet and the appropriate displaced affected EGU emissions rate can be used to determine the prorated percentage of CO_2 savings a MWh of power produced by CHP represents compared to a MWh of displaced EGU power. This percentage can be applied to the net output of the CHP system (or systems) to determine the amount of eligible MWh that could be applied as a correction to the state's emissions rate equations used to set targets and track progress. The total CO_2 savings can also be determined by multiplying the prorated MWh percentage by the total CHP MWh produced and the appropriate CO_2 emissions rate of displaced EGU power.

Two different approaches have been used in federal and state regulations and guidance documents to account for the efficiency benefits of the thermal output of a CHP system and estimate the effective emissions rate for CHP:

- **Equivalence approach** – This approach estimates the effective emissions rate based on the total energy output (thermal and electric) of the CHP system. The thermal output of the system is added to the electric output (in consistent units) in the denominator to calculate an effective emissions rate (lbs/MWh) for the CHP unit. This is the approach that EPA adopted in the proposed §111(b) rule for new power plants and previously in the NSPS for utility boilers (40 CFR Part 60 Subparts Da and Db) and for stationary gas turbines (40 CFR Part 60, Subpart KKKK). This method maximizes the total output recorded (i.e., the denominator) and reduces the lbs/output emission rate of the CHP system. To apply this method, measurements of the input fuel, and used thermal and electric outputs of the CHP system are needed. The equivalence method is relatively straightforward because the regulating authority does not *need* to consider details about the boiler or heating/cooling that were displaced by the CHP system.[74] EPA has sometimes applied a factor to the thermal output (i.e., "discounting") when determining the amount of thermal output to be credited (e.g., the proposed CPP rule suggested that 75 percent of the thermal output be credited in developing the effective emissions rate for affected CHP EGUs).

- **Avoided emissions approach** – This approach is the method used to determine the effective emissions rates in Table 1 above. This method relies on identifying the incremental CO_2 emissions from the CHP system over and above the emissions that would have been generated in producing the same amount of usable thermal energy for the site. The first step is to determine the amount of emissions that a conventional thermal system (boiler or heaters) would have otherwise emitted had it provided the same thermal output as the CHP system (i.e., by generating steam or hot water on site). The measured emissions of the CHP system are then reduced by the emissions that would have been produced onsite to provide the same thermal output without the CHP system (i.e., considering emissions from the CHP unit and subtracting emissions that would have occurred from a "counterfactual boiler" – the boiler that is now not needed), to obtain the incremental emissions attributable to electricity generation. These incremental emissions are then divided by the net electric output of the CHP system to calculate an effective emissions rate. The avoided emissions approach relates the value of the thermal output of the CHP system more directly to the emissions actually avoided by the CHP system. As with the equivalence approach, measurements of input fuel and used thermal and electric outputs are needed for this method. Additionally, consideration is needed about the type and performance of the boiler or heaters that are displaced by the CHP system or systems.

These two approaches can result in slightly different calculated effective emission rates and different compliance measurement or data requirements. Depending on the circumstances, the equivalence approach could simplify certain steps in calculating an effective emissions rate for CHP; however, EPA has recognized that the avoided emissions approach "provides for a more complete accounting of the environmental benefits of CHP by including the emissions avoided by the CHP system's secondary output in the calculation."[75] Both approaches have been used in output-based emissions standards at the federal and state level. [76] Under either the equivalence or avoided emissions approach, state emissions standards typically include minimum efficiency requirements to ensure that the CHP system is more efficient than the separate heat and power generation (central station generator and on-site boiler) it is displacing.[77]

[74] This document refers to "boilers," but emissions from displaced process heaters can be considered similarly.
[75] U.S. EPA, CHP Partnership, Feb. 2013, "Accounting for CHP in Output-Based Regulations" (http://www.epa.gov/chp/documents/accounting.pdf).
[76] U.S. EPA, Aug. 2014, "Output-Based Regulations: A Handbook for Air Regulators."
[77] *Id.* (typically requiring at least 20 percent of the fuel's recovered energy to be thermal and system efficiency of 55 to 60 percent).

Example Calculation

A number of commenters to the June 2014 draft CPP stated that the most accurate approach to estimating CHP credits would be to calculate the effective emissions rate of the non-affected CHP system (or fleet of non-affected systems in a compliance area) using the avoided emissions approach based on measurement of – or reasonable assumptions about – the usable thermal output and characteristics of displaced onsite boilers. The credit awarded would be determined by using this effective emissions rate to determine the specific emissions reductions directly, or to prorate the MWh electric output of the CHP system in comparison to the emissions rates of the affected EGUs.

Below is an example calculation demonstrating the avoided emissions approach for calculating the effective emissions rate and estimating overall CO_2 savings follows for a hypothetical 7 MW natural gas fuelled combustion turbine CHP system situated in Illinois. This calculation is consistent with the approach used in Tables 1 and 2:

Example Calculation for CHP CO_2 Credit

CHP Net Electric Capacity:	7 MW
CHP Net Electric Efficiency:	28.9%
CHP Useful Thermal Capacity:	34.30 MMBtu/hr
CHP Annual Capacity Factor:	80% (7,008 full load hours)
Annual CHP Electricity Output:	49,056 MWh
Annual CHP Useful Thermal Output:	240,410 MMBtu
Annual CHP Fuel Input (natural gas):	579,166 MMBtu
Annual CHP CO_2 Emissions:	33,852 tons lbs
Annual Displaced Boiler Fuel (natural gas): (Based on an <u>assumed</u> 80% boiler efficiency)	300,513 MMBtu
Annual Displaced Boiler CO_2 Emissions:	17,565 tons
Displaced EGU Emissions Rate:	1,895 lbs CO_2/MWh
(2012 Average Fossil Generation Emissions Rate for Illinois)	
T&D Losses:	6%
Displaced EGU Emissions Rate with T&D Loss:	= (1,895) / (1-6%) = 2,016 lbs CO_2 / MWh

Step One: Calculate an effective emissions rate for the CHP system

= *(Annual CHP CO_2 Emissions – Annual Displaced Boiler CO_2 Emissions)*
(Annual CHP Electricity Output)

= (33,852 tons – 17,565 tons) / 49,056 MWh

= 664 lbs/MWh

Step Two – Option 1: Calculate total CO_2 savings from CHP directly from the difference in emissions rates

= (*Displaced EGU Emissions Rate w/T&D Loss – CHP Effective Emissions Rate*) * (*Net CHP Generation)*

= (2,016 lbs/MWh - 664 lbs/MWh) * 49,056 MWh

= 33,162 tons

Step Two – Option 2: Calculate total CO_2 savings as a prorated credit of displaced grid electricity

Calculate prorated MWh Credit for CHP

= *(Displaced EGU Emissions Rate w/T&D Loss – CHP Effective Emissions Rate)* / *Displaced EGU Emissions Rate w/T&D* Loss

= (2,016 lbs/MWh - 664 lbs/MWh) / 2,016 lbs/MWh

= 67%

(Every MWh of electricity generated by the CHP system is equivalent to 0.67 MWh of displaced grid electricity in terms of CO_2 reductions)

Calculate total CO_2 savings from CHP

= (*Net CHP Electricity Generation) * (Prorated CHP MWh Credit) * (Displaced EGU Emissions Rate w/T&D Loss)*

= 49,056 MWh * 67% * 2,016 lbs/MWh

= 33,162 tons

What Is the Appropriate Displaced EGU Emissions Rate for Crediting CHP (and End-Use Efficiency)?

Specific EPA guidance will be needed to establish the appropriate displaced grid emissions rate to be used for savings calculations for both end-use energy efficiency and CHP. The proposed rule identified several methodologies to calculate the emissions impacts of MWhs of end-use energy savings, including adding the MWhs from end-use efficiency to the denominator of affected EGU emissions rates, or subtracting estimates of avoided emissions from the efficiency MWhs to the numerator of affected EGU mission rates. The proposed rule does not, however, explicitly define what specific EGU emissions rates are to be used for determining the emissions savings. For instance, savings could be based on the average emissions rate of the affected EGUs in a targeted area, the average all generation rate for that area, the marginal rate, or the state target rate. The proposed rule mentions each of these possibilities without providing specific guidance on which rate is more appropriate or which gives the best measure of the operational and build benefits of CHP or end-use energy efficiency. However, most analysts believe that using the state's overall emission rate target as the basis significantly understates the CO_2 reductions displaced from the power grid and affected EGUs by CHP. Rather, basing the emissions savings of CHP generation and end-use efficiency on the emissions rates of affected EGUs provides a more accurate estimate of CHP emissions benefits.

EPA also did not provide specific guidance on how to calculate savings over time from affected EGU output displaced by beyond-the-fence measures, such as CHP and end-use efficiency. The emission rates of affected EGUs will change over time as compliance measures are implemented and demand changes. Estimating the energy and emissions displaced by CHP (and end-use efficiency) requires an estimate of what mix of fossil generation is ultimately avoided by the use of power generated by CHP. An accurate estimate of the avoided heat rate and emissions could be made with the use of an electricity capacity dispatch model to determine how the dispatch mix for a given region and the generation resources and emissions are impacted by the reduction in the system demand curve resulting from the addition of CHP resources. In one study of this type done by the Center for Clean Air Policy,[78] the results indicated that baseload on-site generation (which is the operating mode of most CHP systems) displaces a mix of central station fossil generators depending on the location and operating characteristics of the CHP project; it does not displace only one technology such as natural gas combined cycle. However, dispatch models are complicated and costly to run. It is likely that states will seek some alternate method of estimating the impact of CHP and efficiency that will meet EPA guidelines. In the past, EPA specifically recommended the use of eGRID emissions factors and heat rates for the eGRID subregion where the CHP system is located as the first level of estimating displaced grid savings. Although not as accurate as a detailed dispatch analysis, EPA suggested that the eGRID average fossil fuel emission factor and heat rate are reasonable estimates for the calculation of displaced emissions and fuel for a baseload CHP system (i.e., greater than 6,500 annual operating hours). Similarly, for non-baseload CHP systems with relatively low annual capacity factors (i.e., less than 6,500 annual operating hours) and with a relatively high generation contribution during periods of high system demand, the most appropriate estimate of displaced generation is represented by the eGRID non-baseload emission factor and heat rate[79]. For an additional level of preciseness, EPA has developed the *AVoided Emissions and geneRation Tool* (AVERT) to estimate the emission benefits of energy efficiency and renewable energy policies and programs, which could be used to estimate displaced generation from CHP and end-use efficiency.

While EPA did not address the issue of displaced emissions in the proposed rule, it provided relevant guidance in a subsequent Notice of Data Availability (NODA) in response to comments that the goal-setting equations in the proposed rule do not reflect the possibility that incremental renewable energy and energy efficiency may, over time, reduce the 2012 baseline levels of fossil generation that EPA had used in the denominator of the goals formula.[80] In its October 2014 NODA, EPA provided additional guidance on how fossil fuel generation could be "backed out" by such measures as part of the goals setting methodology. The NODA provided two approaches to displacing existing fossil generation: The first replaces historical fossil fuel generation on a *pro rata* basis across all fossil-generation types (coal, gas and oil steam, natural

[78] Catherine Morris, 2001, Center for Clean Air Policy, "Clean Power, Clean Air and Brownfield Redevelopment."

[79] "Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems", U.S. EPA Combined Heat and Power Partnership, February 2015.

[80] U.S. EPA, Oct. 30, 2014, 79 Fed. Reg. 64543, Notice of Data Availability, "Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units."

gas turbine). The second allows the state to prioritize the replacement of historical fossil generation – preferentially replacing fossil steam generation, rather than assuming a *pro rata* decrease across all fossil generation. Although EPA would likely approve state plans that included more accurate estimates of displaced emissions (such as through the use of the AVERT model), it would seem reasonable that, at a minimum, it would also approve the approaches the agency itself used to set state goals.

How Are CHP Credits Applied?

While EPA is expected to issue the final state goals in rate-based form (i.e., a state's plan must not exceed a certain level of emissions per unit of power generated by covered power plants (lbs/MWh)), EPA has indicated that states will have the flexibility to pursue either a rate-based approach or mass-based approach in their state compliance plan. Under a mass-based approach, covered power plants would not exceed an aggregate emissions level in tons that is derived from the rate-based standard EPA prescribed for the state.

Rate-Based Approach: Under a rate-based approach, states have specific emissions-rate targets (i.e., lbs CO_2 / MWh) that must be met over time. As shown above, when thermal output is properly recognized, well designed and properly operated CHP systems generate electricity at a lower effective emissions rate than most affected EGUs and proposed state targets. Under a rate-based approach, CHP generation and emissions savings data can be used to affect "corrections" to both the numerator and denominator of the state's rate equations. Choices for doing the corrections include the following options:

- **Numerator and Denominator Correction**: Incremental CO_2 emissions in tons from non-affected CHP are calculated as above (incremental CHP emissions equal total CHP emissions minus the displaced emissions from a boiler or thermal energy source that would have provided the same thermal output as the CHP system) and added to the annual emissions from affected EGUs in the numerator of the compliance rate equation. The full net electric output of the CHP system in MWh, with a correction for T&D losses, is added to the denominator of the compliance equation along with other end-user efficiency MWh savings[81].
- **Numerator Correction:** The CO_2 savings from non-affected CHP are calculated as described above using annual performance data from the non-affected unit(s) and are subtracted from the numerator of the compliance equation.
- **Denominator Correction:** Displaced electricity savings (MWh) are calculated by dividing the CO_2 savings from non-affected CHP units (tons, as calculated above) by the appropriate EGU emissions rate for displaced grid power and added to the denominator of the compliance equation. Alternatively, as described earlier, the net electric output of the non-affected CHP units (MWh) can be prorated by a factor that discounts the emissions reduction value of the CHP output based on the appropriate EGU emissions rate for grid power and the effective emissions rate for the CHP unit(s). As shown above, the CO_2 savings value of one MWh of CHP electricity output can range from 50 to 80

[81] This was not included in the EPA proposed rule, but was identified in comments as an approach to address net emissions from no- or low-carbon generation.

percent of the emissions rate of one MWh of displaced grid power depending on CHP system efficiency and the level of thermal utilization.

Mass-Based Approach: Under a mass-based approach, the state's rate-based emissions targets are converted to overall emissions targets in terms of annual tons of CO_2 released. This opens the potential for energy efficiency and CHP to participate under a "cap and trade" or portfolio approach (e.g., RGGI). However, careful framework design will be needed for full CHP participation and adequate recognition of benefits. A key issue to address is "leakage' from the "incremental" emissions from un-affected CHP units that are reducing electricity output and CO_2 emissions, from affected EGUs.

One approach to addressing leakage is to add the incremental emissions from non-affected CHP systems to the total CO_2 tonnage for the state. The incremental emissions would be the total emissions of the CHP system or CHP fleet minus the emissions from a thermal source or sources (such as boilers, hot water generators, or absorption chillers) that would have provided the same thermal output. CHP development could be incentivized through existing state or rate-payer programs, or through set-asides in cap and trade programs.

Appendix D

Key Resources

General Information	
Title/Description	**URL Address**
CHP/DHC Country Scorecard: United States. IEA's 2008 U.S. scorecard discusses the status of CHP and district heating and cooling (DHC) in the United States, along with existing barriers and drivers for CHP development.	http://www.iea.org/chp/countryscorecards/
Combined Heat and Power: Effective Energy Solutions for a Sustainable Future. This 2008 report from the Oak Ridge National Laboratory projects economic and environmental benefits from a scenario in which CHP provides 20 % of U.S. electricity generation.	http://info.ornl.gov/sites/publications/files/Pub13655.pdf
Utility Incentives for Combined Heat and Power. This 2008 EPA report surveys existing utility CHP incentives and provides a case study of several successful CHP projects that received support through these	http://www.epa.gov/chp/documents/utility_incentives.pdf
National CHP Roadmap: Doubling Combined Heat and Power Capacity in the United States by 2010. This 2010 USCHPA paper emerged following a multi-year stakeholder planning process. The report identifies key stakeholders and lays out policy priorities to achieve ambitious deployment goals.	http://energy.gov/eere/amo/downloads/national-chp-roadmap-doubling-combined-heat-and-power-capacity-united-states-2010
Combined Heat and Power: A Clean Energy Solution. This 2012 DOE and EPA paper provides a foundation for national discussions on effective ways to reach the President's 40 GW CHP target, and includes an overview of the key issues currently impacting CHP deployment and the factors that need to be considered by stakeholders participating in the dialogue.	http://www.epa.gov/chp/documents/clean_energy_solution.pdf
Executive Order 13624 (2012). Accelerating Investment in Industrial Energy Efficiency. Establishes Administration goal of 40 GW of new CHP and estimates economic and environmental benefits of achieving this goal.	http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency
Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans. This 2012 EPA guide provides four pathways for state agencies to include energy efficiency/ renewable energy in state air-quality plans. It does not explicitly address CHP, though the guidance is applicable to CHP policies.	http://epa.gov/airquality/eere/pdfs/EEREmanual.pdf

The Opportunity for Combined Heat and Power in the United States. This 2013 document from the American Gas Association and ICF International provides a market assessment of CHP potential in the United States, with a focus on impacts to the natural gas industry.	https://www.aga.org/opportunity-chp-us
Guide to Using Combined Heat and Power for Enhancing Reliability and Resiliency in Buildings. In the wake of Hurricane Sandy, this 2013 DOE and EPA report discusses opportunities for CHP to contribute to reliability and resiliency, options for CHP financing, and how to determine if CHP is an appropriate fit for various applications.	http://epa.gov/chp/documents/chp_for_reliability_guidance.pdf
Combined Heat and Power: A Resource Guide for State Energy Officials. This 2013 resource guide from the National Association of State Energy Officials provides State Energy Officials with a technology and market overview of CHP and ways in which they can support CHP through state energy and energy assurance planning, energy policies and utility regulations, and funding/financing opportunities for CHP. Includes examples of successful policies to overcome environmental, regulatory, and financial barriers to deployment.	http://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf
Guide to the Successful Implementation of State Combined Heat and Power Policies. This 2013 report from the SEE Action Network provides state utility regulators and other state policy-makers with actionable information to assist them in implementing key state policies that impact CHP. Includes best practices for interconnection, standby rates and portfolio standards.	https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies
How Electric Utilities Can Find Value in CHP. This 2013 ACEEE white paper explains the major benefits CHP confers to electric utilities and offers specific examples of how electric utilities today are enjoying the benefits of CHP.	http://aceee.org/white-paper/electric-utilities-and-chp
Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities. This 2013 DOE report profiles critical infrastructure that remained operational during recent extreme weather events.	http://energy.gov/sites/prod/files/2013/11/f4/chp_critical_facilities.pdf
Combined Heat and Power Systems: Improving the Energy Efficiency of Our Manufacturing Plants, Buildings, and Other Facilities. This 2013 issue paper by NRDC provides a series of detailed case studies elaborating system attributes and benefits.	http://www.nrdc.org/energy/files/combined-heat-power-IP.pdf
Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do? This 2014 document from the National Regulatory Research Institute examines barriers in state regulations that obstruct the development of CHP.	http://energy.ky.gov/Programs/Documents/NRRI Report-What Can Commissions Do.pdf

Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector. This 2014 report from the SEE Action Network provides state regulators, utilities, and other program administrators with an overview of U.S. industrial energy efficiency programs and assesses some of the key features of programs that have generated increased energy savings. The report includes project profiles of selected successful utility programs.	https://www4.eere.energy.gov/seeaction/publication/industrial-energy-efficiency-designing-effective-state-programs-industrial-sector
From Threat to Asset: How Combined Heat and Power (CHP) Can Benefit Utilities. This 2014 ICF report provides updated deployment data, considers CHP's benefits, the scale of the opportunity, and potential benefits for utilities (e.g., utility ownership or management of projects, rate basing of projects, reduction in grid congestion).	http://www.icfi.com/insights/white-papers/2014/how-chp-can-benefit-utilities
Five Actions Governors Can Take to Help Industry Save Energy. This 2014 paper is the result of the National Governor's Association policy academy on CHP in 5 states. It provides an overview of successful CHP policies and recommendations.	http://www.nga.org/files/live/sites/NGA/files/pdf/2014/1412FiveActionsGovernorsCanTake.pdf
Combined Heat and Power: Frequently Asked Questions. This EPA CHPP fact sheet addresses several frequently asked questions about how CHP works, as well as the costs and benefits associated with CHP.	http://epa.gov/chp/documents/faq.pdf
Combined Heat and Power Installation Database. This interactive database allows users to identify CHP installation by state, with basic information about all U.S. installations.	https://doe.icfwebservices.com/chpdb/
Implementing EPA's Clean Power Plan: A Menu of Options. This 2015 report by the National Association of Clean Air Agencies includes two chapters on CHP. The report serves as a tool to apprise state regulators of tools to achieve the Clean Power Plan emission targets. It highlights CHP benefits, provides examples of successful state policies, and discusses approaches for measuring emission benefits.	http://www.4cleanair.org/NACAA_Menu_of_Options
EPA Action Guide Policy Considerations for Combined Heat and Power. Highlights state policy opportunities to further CHP deployment. These include financing, regulatory, and utility policies.	http://epa.gov/statelocalclimate/documents/pdf/guide_action_chapter6.pdf
DOE Barriers to Industrial Energy Efficiency and Appendix. This study examines barriers that impede the adoption of energy-efficient technologies and practices in the industrial sector, and identifies successful examples and opportunities to overcome these barriers.	http://energy.gov/eere/amo/downloads/barriers-industrial-energy-efficiency-study-appendix-june-2015

Federal Technical Support	
Title/Description	**URL Address**
DOE Technical Assistance Partnerships (TAPs). DOE's CHP TAPs promote and assist in transforming the market for CHP, WHP, and district energy with CHP throughout the United States.	http://www.energy.gov/eere/amo/chp-technical-assistance-partnerships-chp-taps
EPA CHPP. The CHP Partnership is a voluntary program seeking to reduce the environmental impact of power generation by promoting the use of CHP. The Partnership works closely with energy users, the CHP industry, state and local governments, and other clean energy stakeholders to facilitate the development of new projects and to promote their environmental and economic benefits.	http://www.epa.gov/chp/

Information about States	
Title/Description	**URL Address**
Challenges Facing Combined Heat and Power Today: A State-by-State Assessment. This 2011 ACEEE discusses barriers to CHP along with suggestions for how CHP stakeholders can further the development of the CHP market in the United States and individual states.	http://www.aceee.org/research-report/ie111
ACEEE's State and Local Policy Database. This is an online database that includes comprehensive information on energy efficiency policies currently implemented at the state and local level. The database tracks CHP policies.	http://database.aceee.org/
Portfolio Standards and the Promotion of Combined Heat and Power. This report provides an overview of existing state portfolio standards and their treatment of CHP.	http://www.epa.gov/chp/documents/ps_paper.pdf

Availability of Incentives	
Title/Description	**URL Address**
Federal Finance Facilities Available for Energy Efficiency Upgrades and Clean Energy Deployment: A Guide for State, Local & Tribal Leaders and their Partners. This 2013 multi-agency compendium provides information about a wide array of federal funding opportunities that can be used to support CHP deployment (among other things). Includes resources from HUD, USDA, DOE and SBA.	http://energy.gov/sites/prod/files/2013/08/f2/Federal%20Finance%20Facilities%20Available%20for%20Energy%20Efficiency%20Upgrades%20and%20Clean%20Energy%20Deployment.pdf
Database of State Incentives for Renewables and Efficiency (DSIRE). This website contains extensive information on federal, state, and local programs, policies, and incentives for energy efficiency and renewable energy, including CHP. The database can be searched by program type, including green power programs.	http://www.dsireusa.org
EPA CHP Partnership Policy Portal dCHPP (CHP Policies and incentives database). This is an online database that allows users to search for CHP policies and incentives by state or at the federal level.	http://www.epa.gov/chp/policies/database.html
CHP Financial Tools (PUCO). This webcast provides information about financing options available to organizations interested in CHP development. Topic areas included private financing, utility programs, government incentives, power purchase agreements and CHP project estimation.	http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/combined-heat-and-power-in-ohio/chp-financial-tools-august-2-2012/#sthash.o4QbuGgJ.QaY3WAog.dpbs

Project Development Process	
Title/Description	**URL Address**
Catalog of CHP Technologies. (2014) Provides information on available technologies and capital costs.	http://www.epa.gov/chp/documents/catalog_chptech_full.pdf
Guide to Federal Financing for Energy Efficiency and Clean Energy Deployment. (2014). Provides an overview of federal grants, loans and other financial assistance for an array of energy-efficiency investments, including CHP.	http://energy.gov/sites/prod/files/2014/10/f18/Federal%20Financing%20Guide%2009%2026%2014.pdf
CHP Project Development Handbook. This guide walks project developers through the entire deployment process, from feasibility analysis to A63procurement and operations and maintenance.	http://www.epa.gov/chp/documents/chp_handbook.pdf

CHP Emissions Calculator. The CHP Emissions Calculator compares fuel-specific emissions from a CHP system to those of a separate heat and power system.	http://www.epa.gov/chp/basic/calculator.html
HUD CHP Screening Tool. This interactive tool allows users to quickly calculate a theoretical payback for a system if they enter only utility rates, location, square footage and number of occupants.	http://portal.hud.gov/hudportal/HUD?src=/program_offices/comm_planning/library/energy/software

Guidance on Specific Policy Approaches	
Title/Description	**URL Address**
Output-Based Environmental Regulations: An Effective Policy to Support Clean Energy Supply. This factsheet provides an overview of the benefits of OBR and a survey of states that have adopted them.	http://www.epa.gov/chp/policies/output_fs.html
Output-Based Regulations: A Handbook for Air Regulators. This handbook explains the benefits of OBR, how to develop OBR, and the experience of several states in implementing OBR. This handbook is intended as a resource for air regulators in evaluating opportunities to adopt OBR and writing regulations.	http://www.epa.gov/chp/documents/obr_handbook.pdf
Approaches to Streamline Air Permitting for Combined Heat and Power: Permits by Rule and General Permits. This 2014 EPA fact sheet provides an overview and background on existing state policies that have been adopted to streamline permitting for CHP projects.	http://www.epa.gov/chp/documents/PBRFactsheet-10162014.pdf
Standby Rates for Customer Sited Resources: Issues, Considerations and the Elements of Model Tariffs. This 2009 EPA guide provides an overview of standby tariffs and identifies best practices for rate design.	http://www.epa.gov/chp/documents/standby_rates.pdf
Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States. This 2014 report by the Regulatory Assistance Project identifies best practices for standby rate design and assesses the existing approaches in 5 states.	www.raponline.org/document/download/id/7020

§111(d) Analysis	
Title/Description	**URL Address**
Expanding the Solution Set: How CHP Can Support §111(d) Compliance with Existing Power Plant Standards. This document finds that §111(d) can support the deployment of 10 GW of new CHP installations, with concentrations in the industrial Midwest and Southeast. The report provides state-specific projections. The analysis is very conservative (e.g., it assumes only a 50% acceptance rate for projects with less than a 2-year payback period).	http://ccap.org/assets/CCAP-Expanding-the-Solution-Set-How-Combined-Heat-and-Power-Can-Support-Compliance-with-111d-Standards-for-Existing-Power-Plants-May-2014.pdf
Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution. This 2013 report by ACEEE considers a suite of four energy-efficiency policies (portfolio standards, building codes, appliance standards and CHP) and finds that an emissions standard for existing power plants set at 26% below 2012 levels can be achieved at no net cost to the economy. In particular, it finds that the rule can support nearly 20 GW of new CHP. Analysis is conservative, as it assumes no new economic incentives.	http://aceee.org/research-report/e1401
Navigating the Clean Power Plan: A Template for Including Combined Heat and Power in State Compliance Plans. This 2015 tool, put together by ACEEE, is intended to help states document and claim emissions reductions resulting from the adoption of CHP. It includes background guidance and precedents, particular elements states should address in order to claim emissions reduction credit for CHP, recommendations on how to address these elements, and model language based on a hypothetical compliance plan scenario.	http://aceee.org/white-paper/cpp-chp

CHP By Sector	
Title/Description	**URL Address**
CHP in the Hotel and Casino Market Sectors. This 2005 report and related 2007 market update provide an overview of this market segment and assess energy use and other attributes that make the sector a particularly good candidate for CHP.	http://epa.gov/chp/documents/hotel_casino_analysis.pdf
The Role of Distributed Generation and Combined Heat and Power (CHP) Systems in Data Centers. This 2007 EPA report considers the energy use and other attributes that make data centers particularly good candidates for CHP.	http://epa.gov/chp/documents/datactr_whitepaper.pdf
Opportunities for Combined Heat and Power at Wastewater Treatment Facilities: Market Analysis and Lessons from the Field. This 2011 EPA report presents the opportunities for combined heat and power (CHP) applications in the municipal wastewater treatment sector, and it documents the experiences of wastewater treatment facility (WWTF) operators who have employed CHP.	http://epa.gov/chp/documents/wwtf_opportunities.pdf

Combined Heat and Power: A Guide to Developing and Implementing Greenhouse Gas Reduction Programs. This 2014 EPA report explores the potential use of CHP at government facilities and includes a number of case studies about the same.	http://epa.gov/statelocalclimate/documents/pdf/CHPguide508.pdf
Combined Heat and Power: Project Profiles Database. This DOE database includes a drop-down menu to allow users to search for CHP case studies by fuel type, location, prime mover, market sector, and NAICS code.	http://www1.eere.energy.gov/manufacturing/distributedenergy/chp_database/