Utilities and the CHP Value Proposition

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Executive Summary

Combined heat and power (CHP) is the most efficient way to generate electricity. CHP simultaneously generates electric and thermal energy, squeezing more useful energy from its fuel input. The combined thermal and electric efficiency of CHP usually exceeds 70%, whereas the separate generation of electricity in the U.S. centralized grid system averages about 34%. By generating much more useful energy from a single fuel input, CHP offers tremendous economic and environmental benefits to individual system owners, the local grid, and society as a whole.

While some of the benefits of CHP confer to individual CHP-using facilities, most of them are public benefits, conferring to society and the local grid. Individual facilities cannot fully enjoy system-wide benefits, but utilities can. Utilities are best positioned to help monetize the public benefits provided by CHP, and in turn convey the benefits to all of their customers.

In the United States, it is clear that CHP's system-wide benefits are not well understood. CHP is not the dominant form of electric generation in the United States. The existing 82 GW of CHP currently provides about 12% of U.S. annual electricity production. An estimated 130 GW of CHP potential can be found today in existing facilities. This tremendous potential has remains untapped, with less than 1% of that potential installed annually in recent years.

CHP faces a number of obstacles to increased deployment. The upfront cost of CHP systems is high, and while such investments make economic sense in the long run, most companies are not prepared to make such a large capital investment in equipment that not directly related to their main area of business. CHP is also discouraged by some electric utilities, which have significant influence over the ease with which a CHP system can connect to the local grid and earn revenue from its produced power.

Recognizing the substantial remaining potential for CHP and the substantial challenges facing its increased deployment, President Obama issued an Executive Order in 2012 calling for 40 GW of new CHP by 2020. As a result of the order, the U.S. Department of Energy is supporting regional and state efforts to identify CHP opportunities and address existing barriers. One of the major barriers identified is the fact that while utilities could play an important role in CHP deployment, they are often not economically incentivized to do so.

Utilities are well-versed in making long-term investments, and they are well-positioned to encourage strategically sited CHP that can provide major benefits to the grid. Utilities have existing relationships with most of the customers that would be good candidates for CHP, and they can enjoy many of the benefits of CHP much more directly than individual CHP users might be able. Utilities also have the ability to use ratepayer funds to support projects that will provide system-wide benefits, and their CHP programs can help accelerate market adoption of the technology, all while providing economic and environmental benefits to all energy system users.

Despite these capabilities, utilities — especially electric utilities — are structured and regulated in a manner that often discourages them from fully monetizing the benefits of

CHP. They are also often encouraged to make investments in centralized generation resources rather than distributed generation, realizing greater rates of return on the centralized investments.

CHP offers tremendous direct and indirect benefits to utilities. Most of these benefits are not fully valued today. These include:

- CHP's low cost and more efficient power relative to more traditional centralized power plant resources and related transmission investments;
- CHP's ability to adapt to different fuels depending on availability;
- The speed with which CHP can be deployed relative to other generation and transmission resources;
- CHP's ability to avoid significant line losses on transmission and distribution lines;
- The reduced emissions compliance costs resulting from CHP's increased efficiency and avoided line losses;
- A reduced strain on distribution and transmission systems and a reduced need for distribution and transmission infrastructure and reserve margins;
- CHP's ability to function as a capacity resource;
- CHP's ability to balance system power fluctuations and provide ancillary services;
- The increased and higher load natural gas sales benefits to natural gas utilities; and
- The ability to use CHP to supplement and support greater renewable energy deployment.

A handful of states have enacted policies that specifically promote CHP and encourage the valuation of some of these benefits, but most of the above benefits are still not fully measured and monetized. This results in utilities overlooking CHP as a priority energy resource and failing to incorporate it into their long-term system and efficiency plans.

Valuing the above benefits and providing utilities with a way to fully monetize them and incorporate them into system planning would allow the United States to get much closer to its actual CHP potential. Ways to value CHP benefits and confer these values to the utilities that encourage CHP include:

- Establishing an energy efficiency resource standard (EERS) or other portfolio standard that prioritizes CHP as a critical resource;
- Allowing utilities to earn cost recovery and economic returns on investments in CHP, as they do other generation resources;
- Encouraging utilities to offer dedicated CHP programming within larger energy efficiency programming, and offering performance incentives for exceptional efficiency results;
- Valuing the ancillary benefits CHP can provide and linking the direct valuation of those benefits to the cost-benefit analyses used within energy efficiency programs and resource planning efforts;

- Clarifying the manner in which CHP can contribute to utility compliance with existing and forthcoming state and federal air regulations;
- Allowing utilities to establish third-party businesses that can make the initial investments in CHP capital as a for-profit business; and
- Stipulate that CHP be explicitly considered in all integrated resource planning processes and long-term build-out plans for natural gas and electric utilities.

Changes to state-level regulations and policies will be necessary to encourage the above behaviors. Examples of how this could be done exist in the United States, but these few examples are the result of dedicated work by state- and utility-level leaders and CHP advocates to prioritize CHP. Absent such focused efforts to improve policies, utilities are not encouraged to develop CHP programs on their own.

The potential benefits of increased CHP to utilities and their system users are tremendous; the emissions and cost benefits to society could be substantial. However, these benefits will remain on the table if policymakers and other stakeholders fail to change the paradigms facing utilities considering CHP. Win-win scenarios for utility support of CHP exist, but they currently are the exception to the rule. This report outlines how that reality might change.

Acknowledgments

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This report is one of three from ACEEE in a series on CHP and utilities. The two white papers, also available for free download from ACEEE, are:

- *How Electric Utilities Can Find Value in CHP* (July 16, 2013); a white paper describing specific examples of how electric utilities can monetize the benefits of CHP.
- *How Natural Gas Utilities Can Find Value in CHP* (July 16, 2013); a white paper outlining specific examples of how natural gas utilities are currently finding value in owning and supporting CHP.

Introduction

Combined heat and power (CHP) offers tremendous benefits to individual facilities, local grids, and society at large. Despite these benefits, the potential for CHP remains far above the actual deployed CHP capacity in the United States

CHP faces a variety of barriers, many of them economic in nature. Facilities that are well-suited to CHP can be quite averse to making the type of capital investments CHP requires. Such investments can appear risky to companies primarily engaged in other activities — manufacturing products, treating patients, or educating students. In these situations, utilities are uniquely positioned to help encourage the deployment of CHP systems that can serve local loads and benefit the grid as well.

In recent years, states have largely been the primary architects of CHP policy in the United States. On August 30, 2012, President Obama issued an Executive Order establishing a new national goal of "40 gigawatts of new, cost effective industrial CHP" by 2020 (White House 2012). This is an important and highly visible goal that is bringing CHP to the attention of a wider audience.

Electric and gas utilities will play a critical role in meeting this new 40 GW goal. This is because utilities could move the CHP market in a way no other entities can. Utilities:

- Can leverage long-term relationships built on trust with the largest energy users in their service territories;
- Can, depending on their regulatory structure, earn a guaranteed rate of return on investments made in the regulated side of their business;
- Can enter into long-term contracts with CHP system hosts that offer reliable payments and mitigate some risk;
- Can enjoy and monetize the benefits of CHP to the distribution and transmission grids;
- Can directly experience the air emissions compliance benefits of CHP better than most individual facilities;
- Have access to cheap capital; and
- Can be instrumental in removing some of the biggest individual project barriers, such as interconnection challenges and unfair assumptions embedded in standby tariffs.

Most utilities lack an economic incentive to deploy or own CHP. This is especially true with electric-only utilities. Though utilities are well positioned to make investments in CHP, their business and regulatory structures tend to discourage such activity. As a result utilities are not generally able to experience the economic benefits of CHP.

Before these policies and regulations can be changed, they must be understood. This report seeks to help all stakeholders — utility customers, utilities, regulators, policymakers, and efficiency advocates — understand the economic disincentives and incentives facing utilities that might be considering investing in and supporting CHP systems around the United States.

This report:

- Describes the current CHP market and the potential for additional CHP;
- Discusses the existing regulatory business models of utilities in the United States and the manner in which those models encourage or discourage CHP;
- Identifies the various benefit streams provided by CHP systems to utility systems and society at large;
- Summarizes the existing market constructs in which the above benefits can be monetized; and
- Suggests possible policy and regulatory changes that might further help utilities monetize these benefits.

CHP Today

Combined heat and power systems simultaneously generate electricity and thermal energy, such as steam, from a single fuel input.[1] In this way, CHP systems get more useful energy for unit of fuel, conferring substantial efficiency benefits over the separate generation of electricity and thermal energy. At over 4,100 locations in the United States, CHP systems collectively provide about 12% of the power generated in the United States each year. Today these CHP systems save about 1.8 quads of energy annually[2] (SEEAction 2013; DOE and EPA 2012).

The benefits of CHP over traditional electricity generation are substantial. The average efficiency of grid-provided electricity is about 35%, meaning that of 100 units of fuel burned to generate power, 65 of them are lost as waste heat, either as steam into the atmosphere or as heat dumped into nearby rivers or lakes. While the conventional methods of generating heat and electricity separately yield a combined efficiency of about 45–50%, CHP systems can operate at over 80% combined efficiency. The reduction in energy waste saves energy, saves money, and reduces harmful emissions.

CHP is not a single technology but rather a suite of technologies comprising a variety of prime movers such as turbines and engines. CHP systems can also run on a variety of fuels, such as natural gas, coal, wastes, biomass, and biogas. CHP systems are found in all size ranges, from very small systems for residential use of 2 kW to very large utility-scale systems of hundreds of MWs, and they are found in most markets, from high-rise apartment buildings to hospitals to grocery stores to manufacturing plants.

THE EXISTING CHP MARKET

Despite all of CHP's benefits, the amount of CHP installed pales in comparison to its estimated potential. The United States currently enjoys the benefits of about 82 GW of installed CHP, representing about 8% of the country's total installed electric generating

[1] Recovering existing waste heat and using it to generate power is often considered a form of CHP. Such heat-to-power applications do indeed offer many of the benefits discussed in this report, and should generally be considered as part of the suite of "CHP" discussed throughout this report.
[2] The U.S. consumed about 98 quads of energy in 2010, the majority of which is lost in energy conversion processes (DOE 2013).

capacity. An additional 130 GW is viewed as technically feasible considering only existing facilities and, of that, about 50 GW is viewed as truly economic given current electricity and natural gas prices (SEEAction 2013).

Of the remaining technical potential for CHP in existing facilities, about half of it is located in only six sectors (Hedman 2012). They are:

- Chemicals industry;
- Pulp and paper industry;
- Food manufacturing;
- Office/retail buildings;
- Colleges and universities; and
- Hospitals

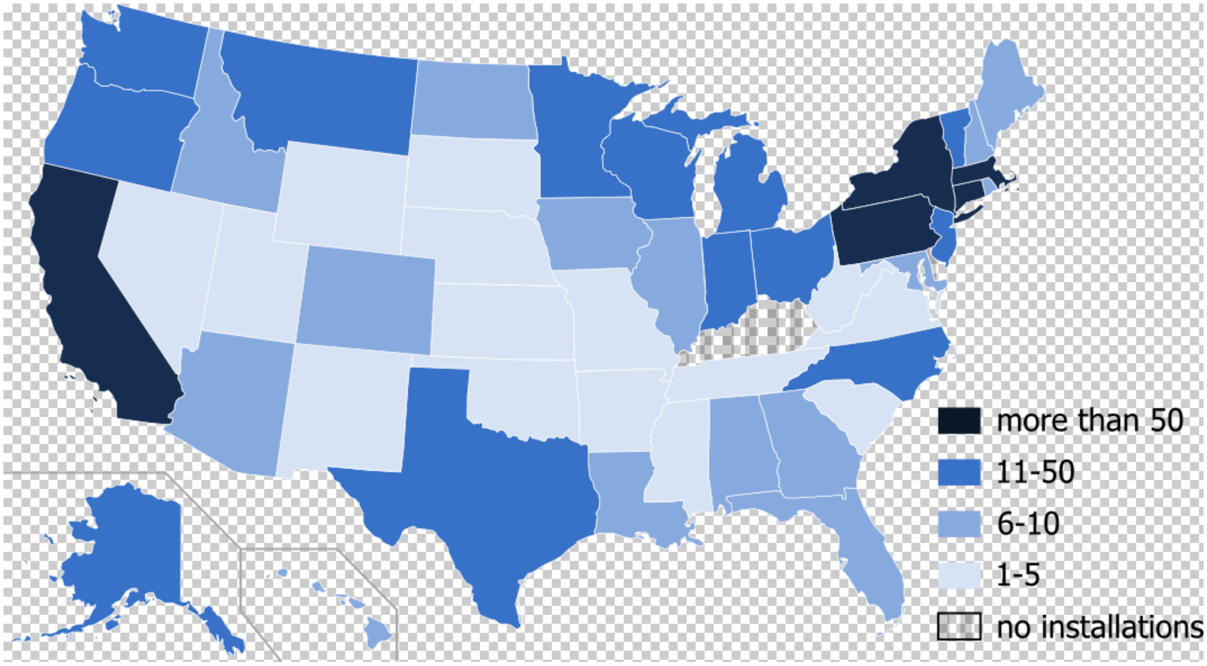
So while CHP can be well-suited to a variety of markets, substantial opportunities are concentrated in certain types of facilities. Additionally, in states that are expecting to retire significant amounts of coal generation in the near future, there exist a significant number of well-suited locations for CHP (Chittum and Sullivan 2012).

The United States saw substantial new CHP capacity in the early 2000s, with annual capacity additions ranging from 2.5 to 6.5 GW in the first years of that decade (Hedman 2011, 2012,). These gains were in part due to federal goals of doubling CHP capacity in the late 1990s and the associated CHP Roadmap activities (see USCHPA 2001). Sharp spikes in natural gas prices in 2005 began to restrain growth significantly, and the latter half of the decade saw less than 1 GW of new CHP capacity each year. CHP capacity growth in the first years of the 2010s has been slowed further by the economic recession. Figure 1 shows which U.S. states have seen the largest number of individual installed CHP projects since 2005. California, New York, Massachusetts, Connecticut, and Pennsylvania lead the country in the number of new CHP projects recently installed.

There is a clear concentration of CHP activity in recent years in California and the Northeast for reasons that will be examined in this report, such as more favorable policies and regulations.

Record low natural gas prices and a growing confidence in consistently low and stable natural gas prices in the near future have helped create a renewed interest in CHP as an energy efficiency resource. New policies and rising state-level energy efficiency targets, as discussed below, have also helped renew interest in CHP as a low-cost and low-emissions energy resource.

Figure 1. Number of CHP Installations by State, 2005-2012



Source: ICF 2012
Notes: In some instances the 2012 data is not fully complete. See ICF 2012 for raw data.

CURRENT PROJECT BARRIERS

The primary barrier holding back CHP developers and would-be CHP owners is the upfront capital cost of each system. The installed equipment cost of a 250 kW microturbine might be about $400,000. Even considering a four year simple payback period, many firms are not currently comfortable making such an investment, especially with the recent recession fresh in their minds. Energy equipment is not a prioritized investment for them, with other capital investments directly related to customer needs or the product line taking precedence. Securing internal approval to seek external financing can also pose a challenge.

The actual cost of operating a CHP system must be compared to a facility's business as usual activities, which would typically include generating steam in a boiler and purchasing electricity from the grid. The difference between the cost of generating power from the CHP system and buying it from the grid is called "spark spread."[3] Spark spread differs dramatically from utility to utility, state to state, and region to region. An unattractive spark spread can prevent a CHP system from moving forward after the initial feasibility analysis is conducted.

Other policy and regulatory barriers can thwart would-be CHP projects. Several of the biggest direct barriers to new CHP projects are poor or nonexistent interconnection standards, and poorly designed standby and backup power rate structures. Interconnection standards delineate the process through which a CHP system will actually connect to the local grid system. And while the standards are promulgated at the state level, CHP systems

[3] More details on spark spread can be found in Chittum and Kaufman (2011).

connect at the utility distribution (or sometimes transmission) level. As a result, interconnection requests are affected by the prerogatives of the local utility.

Interconnection standards are intended to offer CHP system owners a clear and transparent path toward interconnection, but even the presence of such a standard can sometimes leave room for utilities to ask for additional studies, additional fees, and other items that can delay a project and greatly increase the cost of getting the system interconnected.

Standby, supplemental, and backup power rates are the rates utilities use to charge facilities for the backup power a CHP-using facility may require if the CHP system goes down or must be taken offline for maintenance. These are also the rates used to charge facilities for the electricity they purchase to meet their entire facility's power needs, since a CHP's electric generating capacity often meets only a facility's base load electricity needs.

These rates can make or break the economics of some CHP systems. Utilities are largely responsible for developing these rates with regulatory approval, and justify them by noting that even if a CHP system does not use backup power regularly, the utility must have the appropriate infrastructure in place in case the customer does need the power. Some standby rates are particularly punitive, and can dramatically alter the economics of CHP projects. Since the benefits of CHP discussed in this report are not fully calculated, they do not enter into utilities' considerations when they propose their standby rates.

POLICY LANDSCAPE

Many of the economic and policy barriers to CHP vary substantially from state-to-state. Each state's regulatory framework and energy efficiency policies impact whether CHP is viewed as an attractive investment in that state. Additionally, interconnection standards, financial incentives, and standby power rates are mostly promulgated at the state level by utility regulatory commissions or the governing bodies of public utility districts or cooperatives.

The most impactful federal policy pertaining to CHP in the past several decades has been the landmark *Public Utilities Regulatory Policies Act of 1978* (PURPA), which established the official designation of "qualifying facility" (QF). The status of QF was and is bestowed on certain qualifying CHP systems, and PURPA required that utilities purchase QF-produced excess power at rates reflecting the utility's avoided cost of generation. Subsequent federal legislation[4] substantially weakened this requirement, but in certain regions the PURPA QF designation still means utilities are in a "must-buy" situation. However, the state-sanctioned rates most utilities pay for QF power are quite low — for instance, average rates in Ohio range from $0.012 to $0.0413 per kWh — and many CHP developers do not regard PURPA QF status as key to a viable revenue stream for excess power (Wissman 2012; Chittum and Kaufman 2011).

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[4] The *Energy Policy Act of 2005* amended PURPA Section 210 to relieve certain utilities in certain regions of the country where FERC deems there to be a competitive wholesale power market of the requirement that they purchase QF power. Utilities are generally relieved of this obligation if they are located in the Midwest ISO, PJM, ISO-NE, ERCOT, or NYISO transmission markets (FERC 2006).

In more recent years, supportive policies for CHP have largely been developed on the state level, with a few notable exceptions. Federal legislation has encouraged improved interconnection standards with the *Energy Policy Act of 2005*, established a federal tax incentive for CHP with the *Energy Improvement and Extension Act of 2008*, and US Environmental Protection Agency regulator actions under the *Clean Air Act* have clearly prioritized CHP and energy efficiency as a compliance mechanism for certain rules.

States continue to lead in developing the strongest CHP programs, but a 2012 Executive Order issued by President Obama established a goal of 40 GW of new CHP by 2020 (White House 2012). This order represents the first time a true national goal for CHP has been established for the United States, and a clear indication that the current administration is willing to put political capital into the pursuit of the 40 GW goal.

State actions and federally supported CHP activities such as the newly established Technical Assistance Partnerships[5] and the existing Clean Energy Application Centers[6] will be the primary efforts put forth toward meeting the 40 GW goal. Notably, many of these recent efforts, including the work of the Industrial Energy Efficiency and Combined Heat and Power Working Group of the State & Local Energy Efficiency Action Network (see SEEAction 2013), identify utilities as critical partners in meeting the 40 GW goal.

The evolving sense among CHP stakeholders and advocates is that utilities are going to be critical partners in meeting the 40 GW goal. "They hold the keys to the kingdom," said one CHP developer. Utility actions are regularly cited as hampering CHP markets around the country, and so working with utilities to remove those barriers and make utilities active partners in new CHP deployment will be critical to reaching the important national goal.

Utilities and the Future of CHP

Utilities' unique attributes allow them to invest in and take advantage of the benefits of CHP in a way that individual facilities often cannot. Utilities can value and monetize benefits that individual facilities using CHP may not have the time, inclination, or ability to monetize. Utilities can be important partners in new CHP projects and it will behoove everyone interested in meeting the new national CHP goal to understand how utilities could actively participate in a future burst of CHP deployment.

WHY UTILITIES ARE CRITICAL TO THE GROWTH OF CHP

While some of the benefits of CHP confer to individual CHP-using facilities, most of them are public benefits, conferring to society and the local grid (Jimison 2006). Individual facilities cannot fully enjoy system-wide benefits, but utilities can. Utilities are best positioned to help monetize the public benefits provided by CHP, and in turn convey the benefits to all of their customers.

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[5] See details on the U.S. Department of Energy's recently announced Technical Assistance Partnerships funding opportunity here: http://www1.eere.energy.gov/manufacturing/distributedenergy/news_detail.html?news_id=19007

[6] See details of the U.S. Department of Energy's existing Clean Energy Application Centers here: http://www1.eere.energy.gov/manufacturing/distributedenergy/ceacs.html

Electric and natural gas utilities are uniquely suited to support the deployment of CHP within their service territories. Utilities are well-versed in taking the long view on investments as well, and their shareholders are comfortable with the type of long-term investment horizon required for major generation and transmission capital expenditures as well as CHP. The owners and managers of many facilities that could be well-suited to CHP are simply uncomfortable with the longer payback periods of CHP projects, and are unable or unwilling to take on the risk of a capital expenditure that might take four or five years to pay itself back. While CHP assets typically perform for decades, many facilities are more interested in pursuing other energy efficiency upgrades that pay for themselves within a year (Chittum and Kaufman 2011).

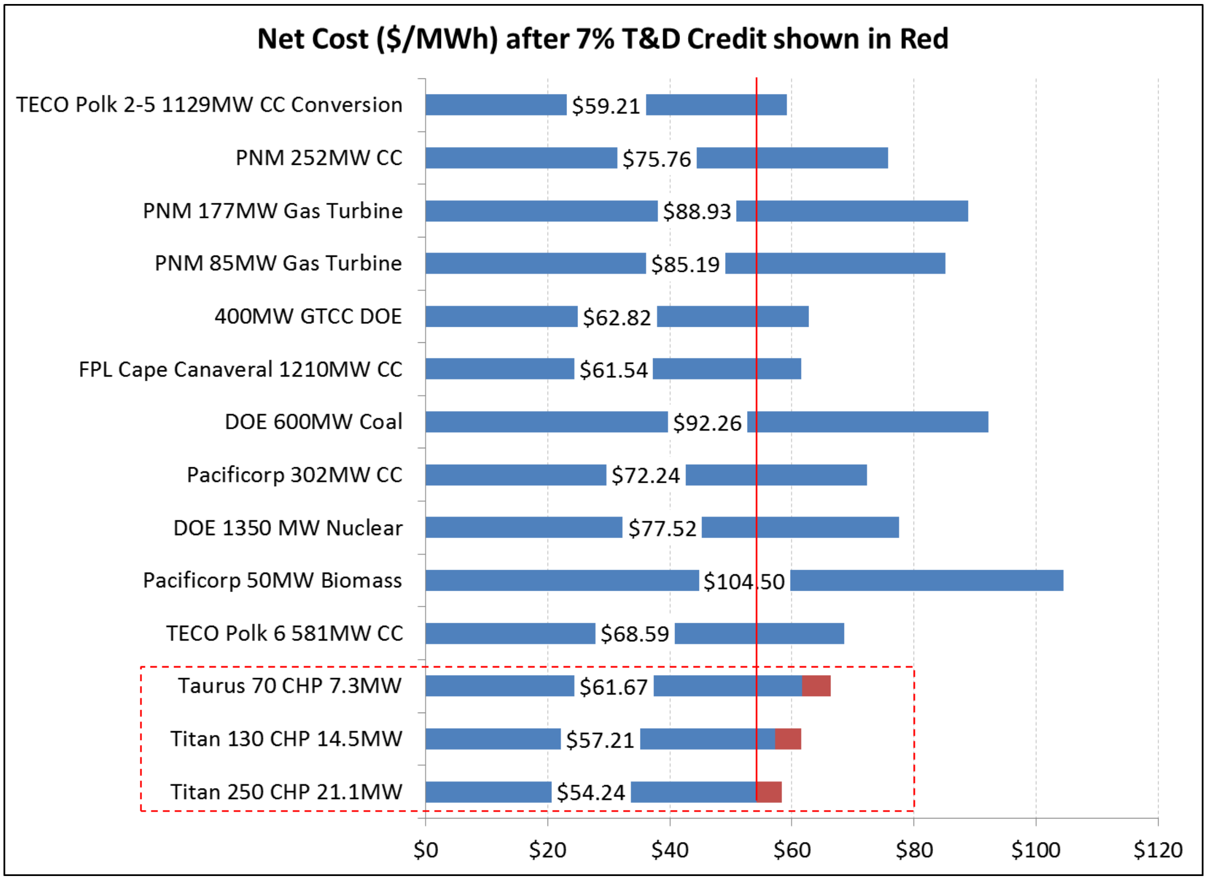
The significant customer service experience and existing asset base of a utility make it extremely well-suited to directly engage in greater deployment of CHP and maximize the efficiency benefits: utilities have existing relationships with the exact facilities that could make excellent hosts for CHP systems; their sheer size means utilities can bring to scale certain technologies or technological applications that had previously been only minimally deployed; and the preferential financing terms utilities enjoy and their lower required rate of return — relative to private CHP developers and owners — could yield CHP projects that offer utilities and consumers lower cost electricity and thermal energy than the status quo (Takahashi 2010).

If major new investments were made in energy efficiency resources such as CHP instead of more traditional assets, consumers, utilities, and utility shareholders would benefit both immediately and in the long term. New natural gas-powered plants, while currently benefitting from lower natural gas prices, are not capturing waste heat and maximizing the useful energy output of the fuel. It thus is costing the utility more to generate each kWh than it would using CHP.

The cost benefits of CHP can be seen in Figure 2. The figure is an analysis provided to ACEEE by Sterling Energy Services LLC. The analysis considers actual generation costs for a variety of resources as reported in different utility resource plans. It assumes a utility ownership model for CHP, including financing terms identical to those for centralized systems. This analysis found that CHP systems of various sizes offer far lower levelized costs per MWh than other non-CHP generation resources.

The cost advantage for CHP holds true when compared with smaller-sized centralized systems as well. While a new 20MW natural gas-powered combined cycle plant can yield power at a levelized cost of about 6.9-9.7 cents/kWh, a new CHP plant can yield the same power at a levelized cost of about 6.0 cents/kWh. For comparison, the levelized cost for nuclear power ranges from about 7.7-11.3 cents/kWh (Chittum and Sullivan 2012).

Figure 2. Levelized Cost of Energy of Selected Generation Resources



Source: Duvall 2013b

If utilities were economically incentivized to support CHP systems, it is likely that some of the utility-based challenges to CHP, such as standby rates that fail to account for system benefits, and a lack of clear interconnection policies, would be minimized as utilities began to view CHP development as in their best interest (Butler and Wissman 2013). Indeed, there is evidence that in states such as New York, Connecticut, and Massachusetts, the growth of established CHP programming offered by utilities has opened the door to improved standby rates and streamlined interconnection processes.

More critically perhaps, utility involvement would yield even greater efficiency benefits and emission reductions. Without utility involvement or encouragement, CHP systems are often limited in size so that most or all of the power is consumed on-site. There are few ways in which CHP system owners are economically incentivized to export power, since prices paid for exported power are often very low. Additionally, many policies and regulations pertaining to CHP, such as incentives and standby rates, encourage or require that the majority of the power generated be consumed on-site. For large industrial facilities — that is, the type of facilities in which the majority of remaining CHP potential remains — the onsite thermal demand is significant enough that sizing a CHP system to meet the thermal demand would generate more power than could typically be consumed onsite. Since there is little economic incentive to build and fuel a system that will produce substantial excess power, CHP systems at major industrial facilities are often constrained by the on-site electric power demand. To maximize efficiency, a CHP system should be sized to and constrained only by a facility's thermal demand. Doing otherwise leaves efficiency gains on the table. With utility involvement, excess power could be sold and having a CHP system with enough capacity to yield excess power would not be discouraged.

Utilities are highly cognizant of the changing loads on their system. They know when new customers are building or expanding facilities and requesting new service; they know when businesses are downsizing or shutting down or changing ownership; they know where areas of their grid are most constrained; and they know where future investments in distribution and transmission infrastructure will likely occur. For these reasons, utilities know, more than any other entity, where CHP systems are best suited and would be most impactful to the grid (Takahashi 2010). In contrast, an individual facility with CHP is much less able to observe and enjoy the immediate benefits of overall reduced grid congestion or reduced overall system emission in the way a utility can.

Challenges in the Utility Business Model

Utilities are often portrayed as enemies to CHP deployment, but in instances where they have thwarted or stalled CHP projects, their actions can usually be traced to the economic disincentives they face from CHP project growth. Additionally, the regulatory framework in which utilities operate often fails to encourage them to pursue CHP deployment.

For decades utilities have struggled with how to view distributed generation within their business models. In 1993, the Electric Power Research Institute (EPRI), whose membership includes almost all of the country's largest electric utilities, considered the impact distributed generation could have on its members:

> *"…distributed generation can be a two-edged sword — new entrants in the market can use it to lure away customers from utilities, and utilities can develop business strategies around the technology that will enable them to retain current customers, grow new markets, and provide new services. The threat of losing market-share has caused many utilities to increase their focus on meeting customer needs and to address local area planning from the customer's perspective…utilities need to be prepared for a radically different future." (EPRI 1993)*

Twenty years later, distributed generation, and CHP in particular, still represents only a minor component of the average utility's generation resources. Indeed, utilities own just 3% of all installed CHP capacity today, and utility-owned CHP represents only 0.23% of all active electric generating capacity (EIA 2013; DOE and EPA 2012).

The reason for this is that fundamentally, the existing utility business structure is not well-suited to CHP. This varies from state to state and depends on the degree to which a state has deregulated its utilities, but ultimately the economic incentives facing utilities are often not aligned with the encouragement of CHP. This is especially true for electric-only utilities.

"The only way we make money is by making a return on an asset. Everything else is minor stuff," says one utility executive. "We're not opposed to CHP, we just need to find a way to win with it," he continued.

This makes sense, especially for investor-owned utilities that must pay for their capital investments, operating costs, and provide value to their shareholders. Energy efficiency projects such as CHP reduce the amount of energy they sell, cutting into the revenues that are the primary way they cover those expenditures. Absent additional revenue opportunities, energy efficiency represents a reduction in revenues that utilities would rather avoid. Black and Veatch, one of the largest builders of centralized power plants in the country, summarized their utility clients' perspective on energy efficiency:

> *Unless given the opportunity to profit from energy efficient investment that is intended to substitute for capital investment, there is a clear financial incentive for a utility to prefer investment in supply-side assets –since they contribute to enhanced shareholder value.* (Feingold 2009).

When utilities invest in new assets and grow their asset bases, their earnings typically increase as well. Regulated utilities are usually able to earn a guaranteed rate of return on new asset investments via increased customer rates, so utilities are incentivized to make investments that will grow their rate base and yield "rate base growth" (Simmons 2012).

While the historic average rate base growth for regulated utilities from 1990 to 2010 was about 3%, there is evidence that for a number of utilities in recent years that growth has reached levels as high as 8% (Simmons 2012). This increase in investment is manifest in a flurry of requests for rate increases across the country.

A recent survey of electricity rate trends in 106 major markets found that for the previous nine years, over half of the surveyed cities saw increased rates, with 17% of markets seeing increases of over 10% in the previous one year period (LES 2012). There are a number of reasons for these rate increases, including aging infrastructure, rising cost of capital, and lower-than-forecasted demand, which forces utilities to attempt recovery of their rate base over a lower-than-expected volume of sales.

Instead of investing in energy efficiency and CHP, many utilities are investing in assets that are not as efficient or cost-effective as they could be, and are raising rates to cover those investments. For instance, AEP Ohio, which is increasing its rates for customers by 12% between 2012 and 2015, cites substantial increases in distribution costs as the primary reason for its rate increases — increases that were already forcefully reduced by the Public Utilities Commission of Ohio (Bell 2012; Boss and Gearino 2012).

Investors like regulated utilities precisely because their earnings are very often tied to rates of return on investments that are guaranteed through regulatory processes. Traditional utilities make investments in generation, distribution, and transmission equipment with the expectation that they will capitalize those investments and recover them through the rates they charge customers for service. In most cases utility regulatory commissions allow utilities to earn some set rate of return on their investments, but investments in major equipment for centralized generation are often treated differently than investments in energy efficiency, such as CHP.

Consider, for instance, Units 3 and 4 currently being built at the Vogtle nuclear plant near Augusta, Georgia by several utilities, including Georgia Power. The plant is the first U.S.

nuclear plant to be approved for construction in over 30 years, and is estimated to cost about $14 billion (Mufson 2012). Georgia Power is approved to earn an 11.15% return on its 45.7% investment in the plant, and can ask for rate increases to make up the difference if the actual return on investment dips below 10.25% (Henry 2010). These are significant profits for any business to earn, and the fact that they are guaranteed via regulatory authority confers the added benefit of reduced risk to investors. It is not surprising that Georgia Power's parent company, Southern Company, has consistently outperformed both the S&P 500 and the Dow Jones utilities average during the past five years as plans for Plant Vogtle became more firm (MarketWatch 2013).

At the same time, Georgia Power is allowed by statute to recover costs and earn "an additional sum" (return on investment) for energy efficiency investments. However, the return has been based on the "net benefits" of an energy efficiency program — that is, the difference between the costs associated with the program and the avoided cost of additional energy — rather than the costs of the entire program. Georgia Power can earn a 10% return on the *net* benefits, and only a 3% return on net benefits if the total savings are 50% or less of the original estimated savings. Furthermore, while Georgia Power could collect the return on energy efficiency programming in 2010, it could not in 2011, and could only receive half of the established return in 2012 (GPSC 2010).

In Georgia, the cost recovery mechanism for energy efficiency programming is designed to be set at *the minimum level that will incentivize the company to pursue cost-effective energy efficiency programs* (GPSC 2010). In contrast, the return on investment for major capital expenditures is not designed just to encourage the company to make investments in new centralized generation resources, but to yield an economic profit as well.

Utilities are economically incentivized to make investments in the areas in which their regulators allow good returns. Typical returns on equity for transmission infrastructure are 10 % to 11% (EEI 2013). Investments in distribution infrastructure can also offer significant and reliable returns, so utilities are economically incentivized to make the case for more investments in their distribution resources. Perversely, increased levels of energy efficiency and CHP reduce individual customer peak demands, which then reduce system demand, which may prevent a distribution utility from securing approval from its regulator to make additional lucrative distribution system investments (Andorka 2013).

CHP is usually missing from the earliest energy system plans as well. Integrated resource plans (IRP) are commonly used long-term plans identifying the future energy needs of a utility territory and the available cost-effective energy resources that can meet that need in the future. IRPs typically consider demand-side management activities as well as distribution and transmission constraints and opportunities. IRPs help inform a utility as it plans for investments in future generation and other infrastructure, so how a resource is treated in an IRP can strongly impact how a utility views that potential resource. As discussed later, a very few number of states and utilities do explicitly consider CHP as a resource during IRP activities, but most do not. When utilities do not see and recognize the benefits of CHP as part of their standard operating procedures, they are generally loath to prioritize it, preferring instead investments in assets for which they now they will have a guaranteed return.

CONCERNS ABOUT STRANDED ASSETS

Utilities that might consider owning CHP do not view it as equally reliable an investment as other types of generation. Since the United States does not engage in the same kind of thermal energy planning conducted in other countries, such as Denmark and parts of the U.K., little planning goes into identifying or aggregating thermal loads and matching them with CHP systems. Thus, concerns about finding and retaining reliable thermal energy hosts are common among electric utilities considering CHP investments. The United States also lacks a significant number of district heating systems, which are used in other countries as reliable thermal energy "customers" for CHP units.

Utilities are generally very conservative in their investment activities, because the impact to ratepayers is usually overseen by a regulatory commission, and operating in a capricious manner is frowned upon by consumer advocates and utilities alike. Duke Energy considered the opportunity to invest in customer-sited CHP systems two years ago. Their biggest concern in owning CHP was the risk they perceived in securing a thermal host that would reliably purchase the heat output of a CHP system for twenty years. That kind of a host would be necessary for the utility to view investments in CHP as more cost-effective than investments in a typical combined cycle natural gas plant (Lawrence et al. 2012).

The concern expressed by Duke is an old one, and it's often termed as a concern about stranded assets. "We've seen a lot of turnover in the manufacturing base in our territories. [CHP] doesn't seem like a prudent risk for us to take," explained Jared Lawrence, a Vice President of Duke Energy. However, investments in manufacturing facilities often make them more competitive and more likely to attract additional internal investment. This could help increase customer growth or retention, providing utilities with more — and happier — customers in the future. Duke, though, has decided CHP makes more sense for the time being as a customer-owned resource, procured and supported through energy efficiency portfolios. "Until a customer is willing to come to us and sign a 20-year contract to take a steam product, or willing to have a tenant sign an agreement, we can't invest ourselves [in CHP]," said Lawrence (Lawrence et al. 2012).

In addition to concerns about stranded generation assets, utilities fear having stranded distribution assets when a facility that previously purchased all of its power from the grid begins to generate power itself, on-site. To address this, utilities use standby and backup power fees and exit fees to recover the cost of the distribution and/or generation assets built to serve a facility prior to its switch to CHP. While one utility acknowledged that standby rates "can sometimes be punitive," they were also clear about the fact that transmission and distribution investments are made with an expectation of customer demand for decades. From a distribution utility's perspective, when a facility switches to CHP, that capacity cost has to be covered one way or another. "We don't consider the idea of relaxing standby charges and exit charges lightly," says another utility. "You can't create a winner on one end without creating losers elsewhere."

To be sure, the concern of stranded assets is real. However, certain contractual and technical tools could help mitigate this concern (Duvall 2013a, Chittum 2013). Undertaking thermal energy planning as part of larger long-term energy resource planning activities is one way that utilities could better understand where existing thermal energy loads are, and where future ones might be. Also, it is likely that some of the benefits of CHP systems more than make up for the costs of equipment that are no longer serving as large of a load due to new CHP systems. These benefits are discussed in the next chapter, "CHP and the Benefit Stream."

IMPACT OF STATE'S REGULATORY FRAMEWORK

Since the 1990s, 15 states have fully deregulated their electric utilities, and consumers have a choice of who to buy their retail power from (EIA 2010). There are varying degrees of regulation and competition in the United States, but a fundamental aspect of deregulation is that distribution utilities in deregulated states are usually prohibited from generating power themselves, and states have opened the wholesale market for power to competition (RAP 2011). During the transition to a deregulated environment, many formerly vertically integrated utilities divested themselves of their generation assets, leaving them with an asset base of wires and pipes rather than generators.

Most U.S. states are not fully deregulated, and so still have vertically integrated utilities that maintain monopoly power in both the generation and distribution of power. In these situations, energy efficiency yields reduced revenues unless the utility has some way of recovering the cost of energy efficiency programs. Most states do allow utilities to recover the cost of administering energy efficiency programs, but an additional return is not often part of these proceedings.

In states with fully competitive markets, ownership of generation is typically separate from that of distribution. Energy efficiency programs and resources may be even less attractive to distribution utilities in these states, because actual distribution of power is a much larger percentage of their total revenues, so their business is more dependent on whether the amount of power sold waxes or wanes (NARUC 2007).

To address this, many deregulated states have established energy efficiency goals and other economic incentives to encourage and require distribution utilities to pursue energy efficiency. However, CHP remains but a fringe aspect of most of these states' energy efficiency program offerings, and only a few states exhibit scenarios where distribution utilities are truly economically incentivized to support the deployment of new CHP systems.

Additionally, even in deregulated markets most distribution-only electric utilities are forbidden from owning generation resources, because such investments could yield an unfair advantage over competitors. For instance, distribution utilities have a strong sense of the loads of different customers, making them well positioned to identify potential CHP host sites. While that could help encourage the deployment of CHP, it could also have the effect of deterring potential third-party market entrants from entering the market due to frustration with the distribution utilities' unfair advantage (Takahashi 2010).

Finally, within energy efficiency programming and related policies, utilities are often prohibited from spending energy efficiency dollars or offering incentives for any activity that might qualify as 'fuel switching.' Implementing a new CHP project may indeed require a facility to 'fuel switch,' as a particular fuel is identified as an appropriate choice for the

CHP system, or services provided by electricity are identified as capable of being more efficiently met with a new CHP system.

CHP and the Benefit Stream

CHP can be thought of as providing three distinct products: electricity, thermal energy, and an energy efficiency resource that manifests as a reduced need for additional electricity generation and distribution from the grid (Hedman 2012). Valuing these products has not always been straight forward, and the energy efficiency resource has been especially fraught with questions about appropriate valuation. Though CHP is often thought of as an energy efficiency resource, it is not static like other efficiency resources and offers benefits to the grid beyond just reduced consumption and demand.

The various products of CHP manifest themselves as a suite of benefits to both the host facility and the larger grid and, in some cases, society as a whole. This section will explain the nature and magnitude of these benefits, which are summarized in Table 1, below.

Table 1. Benefits of CHP to Electric and Natural Gas Utilities

Benefit	Benefit Magnitude	Opportunities to Monetize	Example
Low Cost Generation	Major	Rate-based generation resource; energy efficiency resource standard	Alabama, Ohio
Fast and Flexible Development	Medium	Reduced costs	
Fuel Flexibility	Medium	Reduced costs	Louisiana
Avoided Marginal Line Losses	Major	Cost-benefit analyses	
Environmental Compliance, Utility	Major	Clean Air Act regulations	
Environmental Compliance, Customer	Minor	Customer satisfaction	Ohio
System Resiliency	Major	Customer satisfaction; resiliency portfolio standard	New Jersey
Cost-Effectively Meets Transmission and Distribution Needs	Major	Reduced costs	Alabama, New York, Vermont
Capacity Resource	Minor	Capacity markets	
Power Quality	Medium	Ancillary services markets, customer satisfaction	New Jersey
Reliable, High-Load Gas Customer	Major	Increased throughput	Arizona
Gas System Benefits	Medium	Reduced costs for system expansion	
Customer Attraction and Retention	Medium	Sustain customer base; increased sales and accounts	Philadelphia
Support for Renewable Energy Resources	Medium	Renewable portfolio standards; reduced costs	

COST-EFFECTIVENESS, FLEXIBILITY, AND SPEED

The biggest benefit of CHP over traditional centralized generation is its sheer improvement in energy efficiency and thus cost, as reflected in Figure 2. Instead of wasting the thermal energy generated during electricity production, CHP systems capture it and put it to productive use. By increasing efficiency, less fuel is used to generate the same amount of power and thermal energy. CHP system owners choose to implement CHP systems precisely because it will cost them less to meet their onsite energy needs than purchasing or generating separate heat and power. A CHP system may also generate more energy than needed on site, allowing for a revenue opportunity by selling excess electricity in situations where such an option is available.

The efficiency benefits of CHP are well known among individual facilities served by CHP. In New York, a set of modular CHP systems serving a plastics injection molder offers the facility significant efficiency benefits, operating at a total efficiency of about 70%. The system paid for itself in 2.5 years and the company now enjoys a 36% net reduction in its annual energy costs (Gowrishankar et al. 2013). In Arkansas, a wastewater treatment plant using digester gas and natural gas to fuel a 1.1MW system that operates at 85.9% efficiency. This high efficiency and increased use of locally available fuel yields $500,000 per year in annual energy savings, offering the $2 million system a four year payback (SECEAC 2012).

In addition to the efficiency benefits of getting more useful energy out of a fuel, some CHP systems can also accommodate multiple fuels. Others can be retooled to respond to changing fuel opportunities, such as local biomass resources. This efficiency and flexibility yield real economic benefits to system owners. For instance, in Louisiana, a CHP system at a Dow Chemical Company facility can run on several fuels, including natural gas and hydrogen gas (Gowrishankar et al. 2013). The efficiency of the 880 MW plant and the flexibility in its operations yields Dow annual energy savings of over $80 million a year. These kinds of savings are why Dow meets "the vast majority" of its internal company-wide energy needs with CHP in the United States (Dow 2009).

The flexibility of CHP allows system owners to tailor the design and use of their CHP system to respond to real time market conditions. Princeton University's 15MW CHP system is specifically designed to respond to real-time price signals from the PJM wholesale energy market to help maximize the efficiency benefits of CHP. When the price of power rises, Princeton ramps up its CHP system and consequently buys less of the more expensive grid power. In the summer, when the nighttime price of power is low, the university generates power to chill water which it then stores to be used during the day to keep students and faculty cool. The CHP system offers the university flexibility and allows it to take maximum advantage of the benefits of efficiently generating its own power. Princeton saves $2.5 million to $3.5 million in energy costs annually by using its CHP system to power its campus (Nyquist 2013), not to mention the priceless services it provided during Superstorm Sandy.

CHP plants can also be built much faster than most other alternative types of generation and transmission assets. CHP systems require much less time for permitting and acquiring the rights-of-way that larger centralized plants and associated transmission lines require, reducing costs and risks associated with making major capital investments when future customer demand is rather uncertain. The actual construction time of CHP systems is less than that of centralized natural gas plants, reducing the cost of the asset to utilities and allowing them to more tightly pair generation supply with customer demand (IEA 2010a, IE 2010b). Transmission projects are seeing typical permitting times of ten years or more, and for projects already planned, multi-year delays are being caused by permitting and siting issues (Silverstein 2011).

CHP can also alleviate the need to use "peaker plants," by helping to serve loads especially during times of peak grid demand. Peaker plants are generators connected to a system to only supply power during periods of maximum demand for power. These plants tend to be some of the most expensive resources connected to the grid, performing at low load factors and running only when most necessary. For instance, in 2011, Texas' ERCOT market was settling contracts for about $2,000/MWh during the early morning of its peak summer demand day in August. By 4:00pm, at the peak demand period, it was settling agreements at $3,000/MWh, almost entirely with natural gas peaker plants (Doggett 2012). Avoiding the use of peaker plants can provide an economic benefit to all ratepayers.

AVOIDED LINE LOSSES

Lost power over transmission and distribution lines cost power users about $24 billion in 2010, but thoughtfully sited CHP systems could dramatically reduce such losses (Casten 2012). Line losses are often discussed as averages, but as the grid nears its peak capacity, its line losses "rise exponentially," becoming quite dramatic. One analysis found that the marginal line losses incurred during a system peak are equal to about 3 times the average losses (Lazar 2011).

On average, about 7% of the electricity generated at centralized plants is lost in the transmission and distribution to its final destination (EIA 2012b). When CHP-using facilities rely on their CHP system for power and rely less on the grid, it reduces the amount of power needing to be generated, but it also reduces the amount of electricity sent over and then lost in transmission and distribution wires, providing additional ultimate fuel savings at the point of generation.

Since line losses during system peak periods are much bigger, the value of avoiding them with CHP rises exponentially. Indeed, in a 2006 analysis by the Ontario Power Authority of the marginal cost of providing power from a gas turbine during the system's summer peak, the cost of fuel was about $57 per MWh, while line losses added a cost of $115/MWh, representing over 65% of the total cost during that time (OPA 2007).

A separate analysis found that, due in large part to avoided line losses, "80 GW of strategically-placed [distributed generation]" could reduce the actual "peak US generation and transmission requirements by 100-120 GW," offering tremendous economic benefit to all system users as well as the utilities that would be freed from making necessary infrastructure investments (Casten 2012).

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ENVIRONMENTAL BENEFITS

Since CHP reduces actual fuel used to generate an equivalent amount of energy, emissions are reduced as well. Emissions are reduced directly by avoiding them at the point of generation on the electric grid, but they are also reduced by avoiding the line losses and excess generation needed to mitigate the line losses on the transmission and distribution systems.

Using average national emission figures associated with electric generation, the DOE estimates that the average 10MW natural-gas powered turbine-driven CHP system would yield annual emission savings of 42,751 tons of CO_2. If the US were to meet its goal of 40 GW of new CHP by 2020, the new CHP capacity would cut CO_2 emissions by 150 million tons each year — equivalent to taking 25 million cars off the road each year (DOE and EPA 2012).

For utilities facing possible coal retirements due to the changing economics of coal and new and forthcoming air regulations, CHP can offer a low-cost, low-risk alternative to making expensive investments in pollution controls (Chittum and Sullivan 2012). Previous EPA actions and guidance have shown that EPA generally finds that the air quality benefits of CHP can be substantial, and can be used for air quality compliance (EPA 2012, 2000).

Central station power plants require access to significant sources of water for cooling purposes, which is why they are nearly always located on the shores of a lake or river. CHP systems require less water than traditional power plants, because heat that is normally dumped into lakes or rivers is instead used for a productive purpose. This can offer a clear benefit to places like Texas that have recently experienced drought that has brought into question the water use of power plants. Thermoelectric power plants that rely on water bodies for cooling have been strongly impacted by previous droughts, and plants that rely on lake cooling in particular are especially susceptible to drought-based challenges (Harto and Yan 2011).

RELIABILITY BENEFITS

CHP's proximity to end-users yields a high level of reliability when grid-provided power fails. CHP systems are typically located very near the point of demand, and are thus true generation assets located within a distribution system. This helps "harden" and strengthen the grid by protecting users from power outages that are due to downed transmission lines (NEMA 2013). And if the distribution system is compromised, CHP systems with certain technical capabilities can go into "island mode," disconnecting from the grid and providing power just to the buildings with which they are directly connected. This is one of the primary reasons states like Ohio and New Jersey have begun to more strongly encourage CHP (PUCO 2012).

One assessment of the value to individual customers of avoiding power outages found a range of $5 - $25/kWh across all customer classes. Sometimes referred to as value of service (VOS), these benefits of avoided customer outages can be much more significant than even the benefits of avoided capacity investments (Shlatz and Tobias 2007). The VOS reliability benefits are more pronounced by many orders of magnitude when looking just at the impact of outages on manufacturing firms, even for only momentary outages. One meta review of many different utilities' estimates of VOS reliability benefits found that for medium and large commercial and industrial customers, a "momentary" outage costs $96.5 in 2008 dollars per "unserved" kWh (Sullivan et al. 2009).

For an individual facility, reliable on-site generation can mean millions in avoided downtime costs. With the increased proliferation of intelligent machines at industrial facilities, small changes in voltage can wreak havoc on systems powered by sensitive microprocessors. The Corporate Energy Manager of J.R. Simplot, one of the country's largest privately held agribusiness companies in the nation, noted that over the course of two years, 12 separate grid power outages lasting only a half second or less cost the company at least

$7.5 million (Sturtevant 2013). Avoiding these kinds of costs is one of many reasons that J.R. Simplot considers the feasibility of CHP in its facilities when looking to make facility improvements.

While all distributed generation can theoretically mitigate power outages, not all distributed generation is equally resilient. In times of weather crises or other catastrophic events, CHP can help in ways some types of distributed generation cannot. Most CHP relies on the underground natural gas infrastructure and is able to run and provide power regardless of whether the sun is shining or the wind is blowing (NEMA 2013). That makes it an excellent choice for areas and facilities that may require the backup power of CHP in an emergency situation.

To be sure, natural gas distribution infrastructure could also be damaged in a disaster, but recent weather disasters have revealed the gas infrastructure to be quite resilient. Additionally, because CHP is sited close the point of consumption, the wires over which CHP electricity is distributed are much shorter than those for centralized generation. A CHP system is usually located well within the host facility's property line. Falling trees, then, which are often responsible for the damage to distribution lines during storms, are much less of a threat.

Superstorm Sandy was only the most recent extreme weather event to show the reliability benefits of CHP. Unlike backup diesel generators, most CHP units are directly connected to a steady fuel supply and serviced regularly. While diesel generators "experienced serious failures during Sandy," CHP systems were lauded up and down the eastern seaboard for their ability to keep facilities operating and keep people safe, warm, and — in the case of CHP at hospitals — alive (NEMA 2013; Armour et al. 2012). Colleges and universities powered by CHP provided respite and warmth for students as well as neighbors, and housing complexes fortunate enough to have CHP onsite were able to house some of those rendered homeless by the storm (Chittum 2012).

"We don't know what portion of the blackouts could have been avoided with CHP, and what that avoided cost is," said one utility representative. Assessing that would help put a value to avoiding similar situations during such weather events and help justify a "resiliency portfolio" as suggested by some CHP advocates today (Pentland 2013a). Cost and benefit analyses conducted under the auspices of such a portfolio standard would do just that.

The cost facing utilities rebuilding after Sandy is staggering. New Jersey's Public Service Electric and Gas Company (PSE&G) alone reported estimated costs associated with rebuilding its existing distribution and transmission infrastructure post-Sandy to be $250 to $300 million. That estimate was just for the restoration of existing infrastructure, and did not include the cost to "permanently repair PSE&G's damaged infrastructure or to modify the infrastructure to **reduce the risk of damage of future storms**" (PSEG 2012, emphasis added). Those costs appear to be $3.9 billion over ten years, according to the proposed Energy Strong program PSE&G unveiled earlier this year, the costs of which would be borne by ratepayers (PSEG 2013b).

In addition to direct costs, the use of diesel generators for backup power during times of grid failure yields tremendous additional emissions of pollutants, as diesel generators burn much less efficiently and much less cleanly than CHP systems and centralized plants. A current four to five month backlog to buy diesel generators is evidence that facility owners will not be abandoning their backup generators any time soon (Pentland 2013a). Investments in backup power are being made, but it can hardly be called resiliency. The purchase of diesel generators represents a market failure, where better planning and foresight could have avoided the outages all together, and certainly avoided the additional point emissions produced by backup generators during times of emergencies (Lents et al. 2004; Pentland 2013a).

Finally, as with line losses, the reliability risks associated with increased system load rise exponentially as the system nears its peak. Transmission and distribution system equipment, such as transformers, fail at a rate that rises "exponentially as loads increase" (Shlatz and Tobias 2007). Increased on-site generation could further reduce the failure rate of these critical pieces of infrastructure.

AVOIDED TRANSMISSION AND DISTRIBUTION COSTS

Increased efficiency and decreased line losses can mean that CHP can alleviate the strain on challenged transmission and distribution systems. CHP can allow a utility to either postpone additional investments in distribution and transmission infrastructure, or avoid them entirely if a CHP system keeps a certain area from requiring new resources like an additional substation.

Utilities know exactly where their systems are most in need of increased reliability, voltage support, and other assistance. "We have certain pockets where we have [these needs] and we're contemplating having to make new investments in generation and transmission infrastructure in order to maintain the power reliability our customers need…for instance, if we know that an area requires a $2 million investment, and we know that strategically placed CHP systems would help us avoid that investment for 10 years, we can figure out the net present value and give CHP owners 30-50% of that avoided cost," explained a Vice President of Duke Energy (Lawrence et al. 2012).

CHP improves the reliability of a system's load, and can avoid costs beyond just capital investments. The state of Massachusetts delineates why encouraging CHP within stressed distribution makes sense:

> *As a customer class, a group of DG/CHP systems operating within a distribution network will improve the load factor of the network and reduce the probability of high peak network demand. The improvement of the network's load factor over time, thereby should translate into lower demand related capital investments and maintenance costs for [the utility] and subsequently the rate payers.* (MDOER 2013a)

For utilities tasked primarily with the performance of a distribution system, CHP could be considered an important distribution asset, provided it is targeted to areas of the system that would otherwise need near-term investment to accommodate system peak loads or other stresses (Jolly et al. 2012).

A 2008 study found that 70% of all transmission lines and 70% of all transformers were at least 25 years old (Hargett 2012). They need upgrades, but upgrades are expensive. One study found that expanding existing transmission systems to handle additional demand can cost from $200 to $1,000 per kW, and $100 to $500 per kW to do the same on the distribution system (Lazar and Baldwin 2011). Utilities have been upgrading, and according to the Edison Electric Institute (EEI), 2011 saw a record level of investment in transmission and distribution infrastructure by investor-owned utilities and transmission companies (EEI 2013). All told, these utilities spent about $19 billion on new distribution infrastructure and $11 billion on new transmission infrastructure in 2011 (EEI 2013). Based in large part on a survey of its members, EEI also estimated that utilities would spend an additional $54.6 billion on transmission infrastructure alone between 2012 and 2015 (EEI 2012).

At present, companies that build transmission infrastructure generally receive returns on equity of 10 to 11% (EEI 2013), and ratepayers ultimately cover the costs of these investments. So not only will avoiding such investments reduce costs and free up capital for utilities, but ratepayers will enjoy reductions in the costs their rates must cover.

CAPACITY RESOURCE

CHP both reduces the need for new capacity and acts itself as a capacity resource. To hedge against a capacity shortage, utilities maintain excess reserve capacity. As with any risk mitigation plan, there is a cost, and reserve capacity is one that is shared by all users of the grid. When in-place CHP avoids line losses and reduces the centralized power that must be produced, the capacity a utility must have in reserve — the amount needed to meet a hypothetical maximum system demand — is reduced as well, avoiding an even greater total cost for each kWh (Lazar and Baldwin 2011).

To prepare for future demands, wholesale power markets operate capacity markets, which pay generators for their future capacity. Some markets have opened their forward capacity markets to energy efficiency resources, treating it as equivalent to traditional generation resources in its ability to meet future system needs. Participating in a forward capacity market is complex, but the benefits of participation could be substantial. One study found that energy efficiency programs that participate in such a market may be able to offset 10% of the total cost of the portfolio (Jenkins et al. 2008).

Additionally, there is no significant amount of energy storage integrated into the U.S. grid to be tapped during system peaks. Instead, grid operators maintain certain kinds of capacity markets to ensure that levels of customer energy demand will not exceed supply. Unexpected rises in customer demand, an unplanned generator outage, or other grid failure are all events that require immediate dispatch of generation assets that were not scheduled to run. In these cases, “demand-response” capacity resources are given price signals to encourage them to make their capacity available. As discussed later in this report, demand-response markets are one way CHP systems can monetize their capacity resources.

POWER QUALITY, ANCILLARY SERVICES, AND RESERVES

Unlike other markets, the characteristics of electric power require that electric supply must perfectly match demand at every moment (Siler-Evans 2010). In the United States, the standard frequency for the electric grid is 60 Hertz. When the grid supply is not sufficient enough to cover the "moment-by-moment" load fluctuations, the frequency and voltage stability of the grid can vary outside of an acceptable range, causing sensitive equipment to disconnect from the grid. These disconnections can, in the most severe cases, cause the kind of "cascading blackout" seen in 2003 (FERC 2011b). Additionally, as equipment comes online and offline all over the grid, excess power must be absorbed and deficits of power must be overcome in order to maintain the grid's frequency.

To prevent the kinds of variability in power quality that can cause catastrophic problems, transmission system operators purchase ancillary services from the market. These are capacity and energy products separate from the traditional capacity and energy markets. Ancillary services help stabilize the grid and maintain the high level of power quality to which U.S. customers (and their intelligent machines) have become accustom.

The term "ancillary services" describes a family of services, all of which are valued differently, depending on the speed with which they are demanded by a grid operator and the duration of time for which they are sought. These services can be provided by any number of technologies, including CHP, and are subject to highly variable market prices.

There are seven major ancillary services that CHP generators could provide. These are:

- **Frequency regulation service**, which is the highest quality service and most expensive. It helps stabilize the grid's frequency and prevent frequency fluctuations. It must be brought online within one minute.
- **Load following service**, which is similar to frequency regulation but can come online somewhat slower, usually within ten minutes.
- **Spinning reserve**, which is provided by generators already synchronized and operating and ready within seconds or minutes to provide full output service for multiple hours or days at a time.
- **Non-spinning reserve**, which is provided by generators already synchronized with the grid that are able to ramp up to provide service within ten minutes.
- **Supplemental/replacement reserve**, which provides service within 30-60 minutes of request and is used to allow spinning and non-spinning reserves to return to their normal operation.
- **Voltage control/reactive power service**, which immediately responds to stabilize system voltage by inject or absorbing reactive power in order to control it.
- **Black start service**, which is provided by generators that can start by themselves and provide the appropriate reactive power to start additional generators on the system (LCG 2002, Kirby 2007, SEEAction 2013).

The first five services are acquired in hourly markets, whereas the last two are acquired in yearly market cycles. In general, the more flexible a generator is, the more it is able to take advantage of ancillary service markets and provide the more lucrative services (Kirby 2007).

CHP systems do not require new equipment to participate in ancillary services markets, except perhaps improved controls (Webster 2013). One type of service, frequency regulation, does require that a given amount of CHP system capacity be ready and able to provide the service, which reduces the capacity available to the CHP-using facility and may be difficult for some CHP facilities to provide if they were not designed to provide it. Some types of CHP systems, especially those that are already exporting power, are particular well suited to providing ancillary services, and in fact, the use of CHP to provide ancillary services may confer more benefits to the grid than more traditional providers of the services:

> *It's technically feasible to use CHP generators, rather than centralized power plants, to balance supply and demand. And there is reason to believe that CHP generators may be better suited to the task. Some commonly used CHP technologies, such as reciprocating engines, are more amenable to ramping than large turbines. Further, when operating at partial load, generators will sacrifice electrical efficiency but gain thermal efficiency – potentially useful for CHP generators, but not for centralized power plants.* (Siler-Evans 2010)

Utilities interested in owning CHP systems primarily for export purposes might be better suited to participate in ancillary services markets than a facility primarily concerned with meeting their onsite thermal needs and base electric load. One consideration is that CHP systems operated primarily to provide products like ancillary services may not run as efficiently as CHP systems designed to provide steady thermal supply, so their efficiency and emissions performance may suffer and fail to support stated public policy goals (Miram et al. 2013).

Additionally, one key aspect of ancillary services is their ability to help balance intermittent resources such as solar and wind-powered generators. In fact, creative use of CHP can help support the deployment of additional renewable energy resources by offering flexible and quick-scaling voltage and frequency support to the local grid (Andersen and Sorknæs 2011). As renewable energy goals rise, CHP may provide utilities a more cost-effective means of ensuring that grids are not overly compromised by such intermittent resources (Østergaard 2006).

RELIABLE GAS REVENUE STREAM

Natural gas-fueled CHP projects enable natural gas distribution utilities to sell more natural gas, and their economic incentives are better aligned with the deployment of new CHP than those of electric-only utilities. Natural gas distribution utilities — often referred to as local distribution companies, or LDCs — generally earn revenue from the transport and delivery of natural gas, rather than sales of the commodity itself. More CHP means a higher of gas passing through LDC's local gas distribution lines. For example, an analysis of the impact of an increase in Texas of CHP from its existing 20% of electric production to 35% of production by 2025 found that, compared to business as usual, the total natural gas consumption would increase by 3.3 Trillion cubic feet from 2012 to 2025 (Bullock 2011).

CHP systems are different from other users of gas in that their consumption patterns may not correlate at all with system peak, and they are generally high load factor customers, putting significant but steady and reliable demand on the system. CHP can thus allow a natural gas utility to enjoy reduced fluctuation in system demand, and since CHP systems remain in operation for decades, natural gas utilities can plan on the steady demand far into the future, reducing uncertainty in long-term system planning.

SUPPORT FOR RENEWABLE ENERGY

One of the often overlooked benefits of CHP and other types of distributed generation is its ability to improve the economics and performance of renewable energy resources such as wind and solar-powered generation. As noted in the above discussion of ancillary services, certain types of CHP can ramp up quickly to help distribution and transmission networks balance supply and demand. One of the chief concerns utilities have about large-scale deployment of renewable generation is its intermittency (Schröder 2012). Strategically sited CHP could be primed to balance unexpected dips in renewable-powered energy generation, reducing the risk utilities associate with resource intermittency.

Further, since CHP is sited so close to the point of consumption, it reduces loading of the transmission and distribution systems. This, in turn, could free up those resources for the large-scale renewable energy generation sources that are sited very far from major points of consumption (Casten 2012).

Utilities are facing rising renewable energy goals in states around the country. While renewable energy resources offer substantial societal benefits, pressure has been mounting from certain stakeholders to eliminate these renewable energy standards promulgated at the state level (Bull 2013). One of the most frequently cited arguments for repeal is the cost associated with renewable energy resources. CHP could help mitigate cost increases by serving as more cost-effective backup generation and reducing the additional distribution and transmission assets necessitated by increased renewable energy generation.

Value Opportunity in Practice

While CHP offers substantial potential value streams to utilities, opportunities to monetize these values are not widespread. What follows are real-world examples of utilities finding varying degrees of economic value in CHP.

ELECTRIC GENERATION RESOURCES

CHP's cost-effectiveness, flexibility, and the speed with which it can be deployed relative to conventional resources offer utilities a way to keep rates low, reduce expenditures, reduce emissions, and hedge against unknown future energy demand and prices.

There are several ways electric and natural gas utilities have entered into agreements to acquire CHP-provided power or own the units themselves. In recent years, utilities that have established programs and policies to acquire CHP as a generation or energy efficiency resource have largely done so after being required to do so by their regulatory authority or a state-mandated efficiency program. These CHP resources are typically owned by third parties that establish contracts with the utility that outline the price the utility will pay for the provided power. The costs to acquire this power are then either passed through directly to customers or rolled into rate bases in the same manner as other utility investments.

This section discusses some examples of utility-owned CHP as well, many of which are found in the municipal utility sector. Examples of investor-owned vertically integrated utilities owning and operating new CHP generation resources themselves are few for reasons discussed in "Challenges in the Utility Business Model." Some of the more innovative approaches to supporting utility-owned CHP today can be found with natural gas utilities, who view investments in CHP systems as a moneymaking enterprise.

Electric Utility Owned Generation Resource

Some electric utilities have experience owning CHP as a generation asset. In Louisiana, Entergy Power, a non-regulated subsidiary of Entergy Corporation, invested in a 425 MW natural gas-powered CHP system as a joint venture with PPG Industries, Inc., a Pennsylvania-based manufacturer of glass and chemicals. The plant was built in 2003 and now serves PPG and another nearby industrial plant with thermal energy and electricity. The remaining electricity — about half of the system's output — is sold by Entergy's Wholesale Commodities business unit to the wholesale energy market (Bullock and Weingarden 2006; ICF 2012; Power Engineering 2003; Olson 1999). Entergy Corporation has a 50% ownership stake in the CHP system and has sold some of the power via its retail operations in recent years (Entergy 2012).

Two utility-owned CHP systems in Missouri are located at ethanol plants, where they serve the plants with thermal energy and supply the local municipal utilities with electricity. A 10MW plant in Macon and a 15MW plant in Laddonia are the products of agreements between the local utility and the ethanol plants. In both these cases the electric-generating turbine is owned by the utility, and the heat recovery equipment is owned by the ethanol plants. In Macon the total fuel consumed to generate both the electric and thermal power is 26% less than it would otherwise be in separate generation of heat and power (MPUA 2013).

Southern Company owns about 700MW of CHP capacity across its various service territories, with most of the systems sited adjacent to major industrial operations (Cofield 2012; SEEAction 2013). In the service territory of Southern Company's Alabama Power, the costs of these systems have been integrated into the utility's rate base, thus allowing the utility to earn a return on investment equivalent to that which it receives from other types of capital investments (SEEAction 2013).

In Austin, Texas, a CHP system serving the Dell Children's Medical Center is owned by Austin Energy, the local municipal utility. The CHP system is sized to meet all the electric and thermal needs of the hospital. The utility signed a 30-year contract with the hospital, thus offering the hospital increased reliability while offering the utility the peace of mind that it won't be stuck with stranded assets in the future. The 4.3 MW system generates more electricity than the hospital requires, allowing the utility to sell the remaining power to customers within its distribution system. Due to the presence of a district cooling system, the utility can take advantage of and make productive use of the free extra thermal energy as well (TAS 2013; Takahashi 2010; Corum 2007).

Examples of utility-owned CHP are rare, but there is some precedent for cost recovery of utility-owned distributed generation in other types of resources. In Massachusetts, utilities can recover the cost of solar-powered generation resources through a Solar Cost Adjustment

Provision tariff, which allows a utility to recover the costs of the resources, less any revenues earned through the sale of energy or capacity services or renewable energy credits. The utilities' typical allowable rate of return applies (Takahashi 2010).

Utility ownership of solar resources has also progressed in the deregulated market of New Jersey, where PSE&G has invested heavily in centralized solar developments. The utility has developed over 76 MW of new solar resources since 2010 through its innovative Solar 4 All program, and aims to develop a total of 80 MW of solar projects through 2013 (PSEG 2013a). In 2009 the utility was approved to invest $515 million in the first phase of the program, and is able to recover the cost of the program, including a return on equity, through customer rates (NJBPU 2013).

Power Purchase Contracts

Though significantly impacted by the *Energy Policy Act of 2005,* some regions of the country still see PURPA QF status as a construct in which CHP owners can be assured of a particular price for their power that utilities must purchase. However, as discussed earlier, the prices that are paid for PURPA QF output are generally low, and CHP developers and owners are usually not incentivized to enter into new PURPA QF agreements in most states. If utilities paid higher prices for PURPA QF contracts, more CHP developers would likely seek them out, yielding a higher level of CHP-produced power in those service territories. However, absent a significant change in the way PURPA QF prices are set, it seems unlikely that PURPA QF status will regain its former significance.

In California, a 2010 decision by the California Public Utilities Commission (CPUC) proposed a settlement among the state's investor-owned utilities, CHP developers, and consumer advocates to address numerous disputes brought before the CPUC by a wide variety of parties since the establishment of the state's PURPA QF program in the 1980s (CPUC 2010). The ultimate outcome of the settlement agreement among all parties was a "framework for how QFs and CHP could participate in future procurement needs" for the state's investor-owned utilities (Miram et al. 2013).

California is a mostly regulated state, though some customers have been able to buy power directly from competitive suppliers since that "direct access" option became available in 2010. In addition to owning generation units themselves, distribution utilities buy power and capacity on the market, entering into contracts and power purchase agreements (PPAs) with a wide variety of market players. PPAs represent an alternative to the standard PURPA QF contract model, and are generally applicable in both regulated and deregulated markets.[7]

The QF settlement established multiple types of PPA structures CHP system owners could enter into with their local utilities. It also established capacity targets of installed CHP for each investor-owned utility through 2020, and utilities develop requests for offers, with different contractual structures based on system size and other characteristics (Lipman 2013a; Miram et al. 2013).

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[7] CHP developers report that some regulated markets, like Florida, prohibit utilities from entering into PPAs with third-party CHP owners (Plitch 2012).

While most of the available PPA structures offer standard rates for a contracted amount of capacity and energy provided at the discretion of the CHP system owner, the settlement agreement also yielded a contractual structure that treats CHP systems as a dispatchable generation facility, controlled entirely by the utility (CPUC 2013; Lipman 2013a). The dispatchable option was designed for older existing CHP systems where the steam host has been lost but the system owner is interested in transitioning away from a base load operation to a dispatchable model (Miram et al. 2013).

Within the California settlement structure, prices are generally negotiated based on short-run avoided cost rates, and costs to the utility are passed through to customers as non-bypassable[8] charges on rates. Utilities do not earn a return on these contracts, and contracts are prioritized according to their value to end customers. Utilities may plead unable to meet their MW targets if they can show that they did not receive ample cost-effective bids. In-place contracts help utilities meet their resource adequacy requirements,[9] so offer some value to utilities wishing to avoid paying resource adequacy penalties. Ultimately the utilities consider PPA contracts that have real environmental benefits, are affordable for customers, and present no negative impact on grid reliability (Miram et al. 2013).

The settlement agreement contracts are in a nascent stage, and for now it appears the effect will mostly be the continued operation of existing CHP systems. Importantly, though, the program has established a standardized acquisition approach that is uniform across the major regulated utilities (Lipman 2013b). At this point utilities entering into these agreements are seeing the costs simply rolled into customer rates, though the resulting reductions in greenhouse gas emissions can help utilities meet the new requirements under the state's cap and trade program (Neff 2013).

One other utility that has acquired CHP through PPAs is Alabama Power. Alabama Power's recent agreements have largely resulted from re-negotiations with existing PURPA QFs. The cost for the 2,000 MW of CHP deployed within the Alabama Power system incorporated in the rate base, and the CHP systems are largely sited near major industrial operations that have use of the steam (SEEAction 2013).

Standard Offer

In 2010 the Ontario Power Authority, a non-profit entity tasked with acquiring new energy resources, was directed by the Ontario Ministry of Energy to acquire 1,000 MW of new CHP resources (OPA 2011; Duguid 2010). It currently does so via its Combined Heat and Power Standard Offer Program.

OPA may enter into contracts with customers for new CHP, and it may pay prices that cover the customers' investment, operating expenses, and a rate of return. Prices paid to customers also reflect short-term prices of natural gas and energy in the local market (SEEAction 2013). To date, OPA has acquired 414 MW of operating capacity, and another 6 MW are under development (OPA 2013).

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[8] These are charges that all customers, regardless of their particular rate structure, must pay.

[9] In California all energy service providers are required to meet annual "resource adequacy" capacity targets, which ensure system reliability in the future and a reliable grid in the near term.

Feed-in-Tariff

Feed-in-tariffs (FIT) are contracts signed between utilities and generators, typically for a fixed price and period of time. The costs for FITs are usually recovered through rates or through system benefit charges. Distribution utilities generally enter into these contracts and treat the power as wholesale power, though the power does not itself enter the wholesale market (Taylor 2010).

In California, a state-mandated FIT is offered by regulated electric utilities to qualifying CHP systems. The purpose of the program is to encourage CHP systems that are right-sized to meet thermal loads and provide payment for excess electricity to make the projects viable. The program is fairly new and to date, only four projects have been certified, and no contracts for delivery have been signed. Unlike other incentive programs, there is no maximum or minimum dollar amount associated with this program (Neff 2013).

The price paid to generators is based on the short-run avoided cost of power, and contracts are for ten years (Neff 2013). The short-run avoided cost is effectively the cost of a natural gas combined-cycle turbine (Davis and Simchak 2012). Utilities recover the cost of this program through rates.

The structure of the California FIT is designed to help utilities acquire cleaner sources of energy while protecting ratepayers from unexpectedly high resource costs. Unlike older PURPA contracts, the California FITs can respond to changes in market prices of resources and reflect changes in natural gas prices, allowing utilities to better respond to changes in market signals (Taylor 2010; Lipman 2013b). However, FIT contracts are fundamentally structured to pay for generation as the primary product, and prices and contracts are designed without regard to the real-time market for other products a generator may be able to provide. The economic incentives for CHP owners entering into FITs, then, are linked directly to the actual energy production and nothing else. Such a structure may not be well-suited to CHP systems that could more actively participate in demand or ancillary services markets or function as compliments to renewable energy-powered systems (Hollinger and Erge 2012).

FOR-PROFIT BUSINESS CHANNEL

Natural gas utilities and companies that sell both natural gas and electricity are constructing business ventures that explicitly acquire CHP for profit motivations. Lessons from their programs could be applied to other natural gas utilities and electric utilities interested in enjoying some of CHP's value streams.

One large natural gas subsidiary of a natural gas and electric holding company (which chose not to be named due to the sensitive nature of regulatory filings) is currently designing a CHP program and preparing to ask for regulatory approval later this year. The premise of the program is that utility ownership at the beginning of the project's lifespan would help accelerate market adoption, furthering the growth of what it views as a very reliable and high load factor natural gas customer class.

This utility proposes to design, finance, and construct appropriately sized CHP projects for customers, and then own and operate the systems for the first 10-15 years of their lives. To earn revenue, the customer would pay the utility a fixed flat rate each month, and would be allowed to have full use of both the electric and thermal energy generated by the CHP system at no additional cost.

For the customer, the value of this scenario is derived from the difference between the fixed price they pay for the CHP system's energy products and the prices they would be paying if they were buying electricity and producing thermal energy separately. For the utility, the value is a fixed revenue stream that would reflect a similar rate of return as those authorized on other capital assets such as pipes and meters. The revenue stream would cover the cost of equipment, fuel, operation and maintenance needs, and a fixed rate of return. Additionally, the utility would be encouraging the growth and maturity of the local CHP market, which is a steady user of natural gas.

The utility would need the approval from its commission to deploy this program, but sees it as a win-win for everyone. If the efficiency benefits of the CHP system are eventually able to be monetized in an energy-efficiency standard, or as emission reductions in a carbon market, the utility expects to let the owner of the site facility own the credits and sell them as they see fit. The utility is currently working out the business case to prepare its regulatory filing.

Another utility that has worked on perfecting the CHP business case is United Illuminating (UI) in Connecticut, a holding company that includes one electric company and two natural gas companies. UI began exploring opportunities in the CHP market due to the economic opportunities it saw to better market and capitalize its existing natural gas assets.

UI's Zero Capital (Z-Cap) program model addressed one of the fundamental challenges to new CHP projects: a strong aversion to the risk of large capital investments at the facility level. Customers are simply not comfortable with having such large investments on their balance sheets. Z-Cap answered this challenge by proposing to take new CHP systems off of customer balance sheets and taking the concerns about operation and maintenance of the systems off of the minds of facility managers.

Since UI cannot own generation due to Connecticut's restructured regulatory environment, the Z-Cap program proposed to arrange marriages between third party entities and its customers. UI planned to leverage its existing relationship with the customer to act as a free consultant, introducing them to energy service companies that could own a CHP system on the customer site and offer a power purchase agreement to the customer for the energy services. This model is not unlike those used historically for other energy resources, especially solar power (Wood 2013).

In the Z-Cap scenario, customers benefit from lower electric prices that are largely guaranteed for five or ten years. Additional benefits and revenues, such as tax incentives or emissions reduction credits, would accrue to the third party entity. UI worked with facilities such as airports, universities, and hospitals on structuring CHP projects that made sense for them.

UI saw CHP as an opportunity to make money on gas, in an environment in which the margins are very narrow for making money on the commodity itself and the distribution of it. It funded the exploratory Z-Cap matchmaking services out of its business development and new product development budgets, and it considered the prospect of acting one day as the third party. UI was also interested in exploring deployment of CHP as a distribution asset, which would allow them to roll their investments into their rate base.

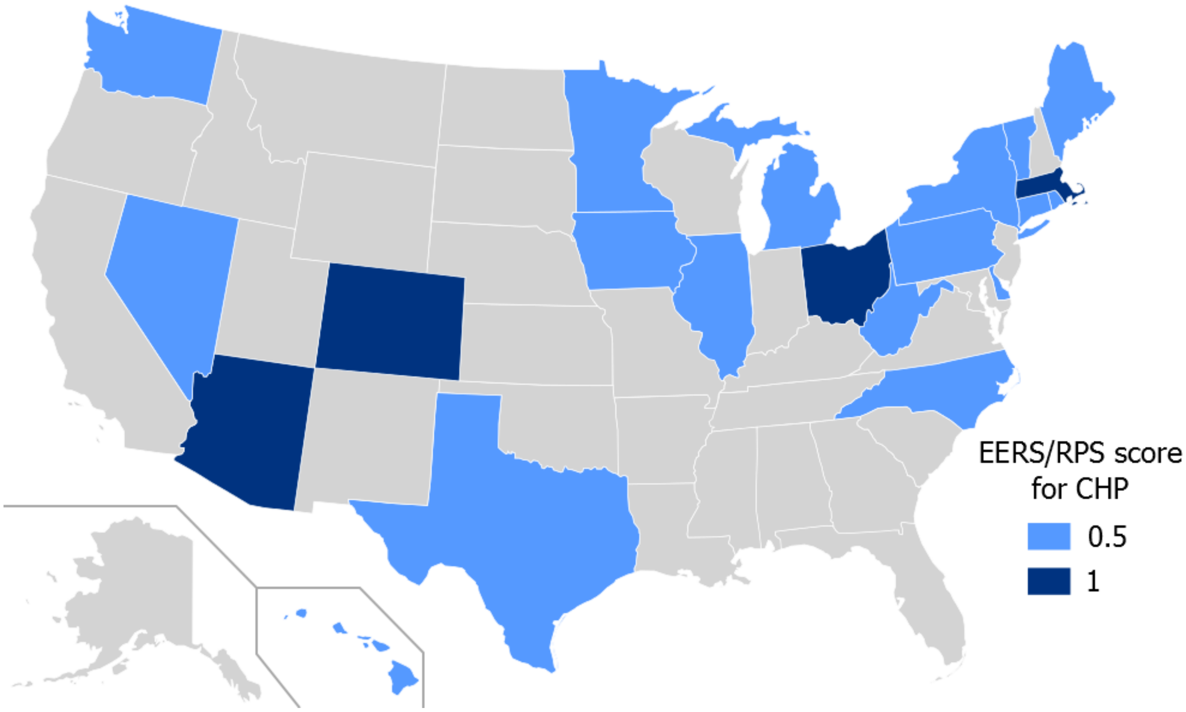
Some natural gas utilities offer discounted rates for the gas that is used to power CHP systems. These rates reflect the fact that the demand for gas from a CHP system is more reliable and less variable than the demand curve of a traditional gas customer, which provides the benefit of reduced capacity needs and reduced investment uncertainty. In New York, the Public Service Commission recognized that existing natural gas rates were developed without considering opportunities like CHP. (NYPSC 2002), and regulated gas distribution utilities are required to offer discounts on gas (Levy 2013).

ENERGY EFFICIENCY PROGRAMMING

Most utilities have at least some energy efficiency programming they offer to their customers, but few utilities explicitly offer programs specifically designed to promote CHP. Costs for energy efficiency programs are usually recovered in rates or through an additional charge to a customer's bill, such as an energy efficiency rider or system benefits charge. Utilities typically recover the costs associated with their energy efficiency programs, but have fewer opportunities to earn significant returns on their investments akin to the returns allowed for new generation or distribution assets.

Figure 3 shows how the 50 states scored for their treatment of CHP within existing energy efficiency resource standards (EERS), renewable portfolio standards (RPS), or other type of energy portfolio standard. This map reflects updated rankings for the forthcoming 2013 version of ACEEE's *State Energy Efficiency Scorecard*. States earned a full point in the EERS category if their portfolio standard was binding; if it treated fossil fuel-fired CHP as a priority resource; and if their treatment of CHP is equal to that of other energy efficiency resources. Only a handful of states identify CHP as a priority resource, carving out very explicit treatment of it within their standards. Many states tend to relegate it to a lower tier of resource, or do not offer clear guidance on how CHP savings might be counted, which leaves utilities with less of an incentive to encourage CHP. These states only earned 0.5 points for such policies in the *Scorecard.*

Figure 3: Treatment of CHP within EERS or Other Portfolio Standard



Source: Forthcoming ACEEE 2013 *State Energy Efficiency Scorecard*

For state that have energy efficiency goals, some utilities report that finding cost-effective energy efficiency resources is becoming more difficult, and CHP is emerging as a low-cost efficiency resource that can help utilities meet their state-mandated efficiency goals at costs lower than most other efficiency resources. The addition of CHP programming to an existing efficiency portfolio is one way utilities are improving the overall cost-effectiveness of their energy efficiency programming.

Identifying CHP as an Eligible Technology

In Massachusetts, the 2008 *Green Communities Act* requires that in addition to the established energy efficiency goals and funding, all cost-effective CHP must be acquired as part of required energy efficiency programming. To support this, utilities offer a rebate for CHP systems of up to $750/kW, with the rebate limited to no more than 50% of installed cost (Massachusetts Session Laws 2008).

To meet the requirements of the Massachusetts law, utilities develop three-year energy efficiency plans, including specific CHP plans, and propose budgets to support the plans. Utilities in Massachusetts are decoupled, and may thus recover the cost of running efficiency programs via their decoupling mechanism and processes, which also address the utility company's lost revenue (Ballam 2013).

Natural gas utilities can also take advantage of CHP's energy efficiency benefits within their own efficiency targets. For the past four years, Arizona's Southwest Gas has offered an incentive program to its customers to encourage deployment of CHP (Brinker 2013). Of the company's total demand-side management budget of $4.7 million, the CHP program is a minor $750,000 program. The costs for Southwest Gas's demand-side management programs are recovered via a small surcharge on customer bills, equivalent to less than $0.01 per therm of consumption (Esparza 2013). The gas company can offer its incentives of several hundred dollars per installed kW, but customers must still contend with electric utilities that are not always supportive of the CHP projects. The program initially struggled to get CHP projects placed, but has recently seen increased interest (Esparza 2013; Brinker 2013).

Just the inclusion of CHP alone does not always yield a direct benefit. In Connecticut, CHP qualifies for participation in the RPS as a Class III resource, but the price of Class III credits has been so low that there is little economic incentive to sell them. This was due partly to the fact that energy efficiency measures could earn Class III credits, which appeared to leave the market oversupplied (CDEEP 2012). Recently, the definition of Class III resources was changed, in the hopes that the Class III treatment would better incentivize CHP as the price of Class III credits rises (Lucchina 2013).

Performance Incentives

Performance incentives for utility shareholders can be tied to energy efficiency program performance, and in cases where CHP is explicitly part of utilities' energy efficiency portfolios, the shareholder incentive can strengthen the economic attractiveness of CHP.

In Massachusetts, where substantial energy efficiency programming has been part of the state's energy strategy for decades, utilities can earn an incentive equal to about 5% of the cost of their *MassSave* efficiency programs by meeting specified savings goals (Hayes et al. 2011). This specter of a 5% reward has been the strongest economic pull encouraging the state's affected electric utilities to support CHP projects, as CHP has played an increasing role in utilities' energy savings performance. In 2011, 30% of the energy efficiency target for the commercial and industrial sectors was met with CHP, at the lowest cost per kWh of all commercial and industrial measures. CHP was critical to utilities earning their performance incentives, and it also helped greatly improve the cost-effectiveness of their entire energy efficiency portfolios. For instance, the cost of saved energy for all MassSave energy efficiency resources acquired in the commercial and industrial sectors was reduced from $0.022 in 2010 to $0.016 in 2011, thanks largely to CHP (MassSave 2012). To receive incentives, CHP systems must have a benefit to cost ratio of greater than 1, and most CHP systems considered for the energy efficiency programs meet that mark (Ballam 2013).

Performance incentives can help mitigate concerns of utilities in decoupled markets. While electric utilities are supposed to be able to recover the cost of lost sales due to energy efficiency measures such as CHP, there is still a perceived risk that the amount regulators allow a utility to recover may not fully compensate them for their losses. Performance incentives help alleviate that concern, and help provide utilities with an additional avenue through which they may earn a "return" on their contributions to these efficiency assets (Ballam 2013).

For AEP Ohio, CHP is being more aggressively pursued in part because the utility can earn additional incentives if it meets 115%% of its energy savings goal (Williams 2012). For AEP, the incentives are "why we are interested in CHP," and CHP is one of the clearest routes to earning those additional incentives because a single project can yield the same savings as a large number of smaller efficiency measures.

Cost-Benefit Tests

Energy efficiency programs that use ratepayer funds use cost-benefit tests to determine whether given energy efficiency projects will yield benefits to ratepayers. Costs, such as up front capital and administrative costs, are compared to benefits, such as reduced need for energy generation, and reduced need for investment in distribution assets. There are many different types of cost-benefit tests, but the main ones used by energy efficiency programs today are:

- **Utility Cost Test**, which measures only those costs and benefits that confer to a utility, and does not consider the costs borne by customers (Shirley et al. 2009)
- **Total Resource Cost (TRC) Test**, which measures the total costs and benefits to both the utility and individual participating customers, and uses those aggregated inputs to determine cost-effectiveness (Shirley et al. 2009)
- **Ratepayer Impact Measurement (RIM) Test**, which measures the cost of the resource to the utility, including lost revenue, and compares it to the cost of avoiding other resources (ECW 2009)
- **Participant Cost Test (PCT)**, which simply measures the cost of the measure to the participant and compares it with the benefits (ECW 2009)
- **Societal Cost Test**, which measures total costs to the utility and participants, including non-energy benefits and other "externalities" (ECW 2009)

How CHP benefits and costs are valued within these tests, and how decisions to move forward with projects are made once test results are derived greatly impacts whether or not utilities pursue CHP within their energy efficiency portfolios. Table 2 demonstrates how some of the different costs and benefits of CHP systems are incorporated into the major cost-benefit tests.

Energy efficiency programs are designed to avoid free ridership, which means that incentives and other support are offered at the level necessary to incent deployment of a technology, and not any higher (Lawrence et al. 2012). However, it is clear that for some utilities, working within their existing cost-effectiveness parameters for energy efficiency programs will only support a minor amount of new CHP systems as many of the previously discussed benefits are completely absent from all the above cost tests.

Table 2. Five Major Cost Tests and Their Treatment of CHP Benefits and Costs

	Utility			TRC			RIM			PCT	Societal
	Elec.	Gas	Joint	Elec.	Gas	Joint	Elec.	Gas	Joint		
Benefits											
Customer Electric Bill Savings										Yes	
Avoided Electric Energy Costs	Yes		Yes	Yes		Yes	Yes		Yes		Yes
Avoided Electric Capacity Costs	Yes		Yes	Yes		Yes	Yes		Yes		Yes
Avoided T&D Costs	Yes		Yes	Yes		Yes	Yes		Yes		Yes
Wholesale Market Suppression Effects	Yes			Yes		Yes	Yes		Yes		Yes
Avoided Environmental Compliance Costs	Yes			Yes		Yes	Yes		Yes		Yes
Reduced Risk	Yes			Yes		Yes	Yes		Yes		Yes
Other Positive Impacts -- Utility	Yes			Yes		Yes	Yes		Yes		Yes
Other Positive Impacts -- Participant				Yes		Yes				Yes	Yes
Other Positive Impacts -- Society											Yes
Increased Revenue (Gas only)		Yes	Yes		Yes	Yes		Yes	Yes		
Costs											
Program Administrator Costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		Yes
Program Financial Contribution for Measure	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		Yes
Participant Financial Contribution for Measure				Yes	Yes	Yes				Yes	Yes
Lost Electric Revenue to Utility							Yes		Yes		
Other Costs -- Utility											
Other Costs -- Society											Yes
Other Costs -- Participant				Yes		Yes				Yes	
Increased Customer Bills (Gas only)					Yes	Yes				Yes	Yes

Source: Adapted from Woolf 2013 and SEEAction 2013

Cost-benefit tests most accurately convey the benefits of CHP if they balance all of the cost assessments with all of the benefit streams. The majority of states use the TRC test to assess energy efficiency portfolios; however, the "other" benefits that accrue to participants, the utility, and society are generally "significantly" undervalued in these tests (Woolf 2013). For instance, the popular TRC test fails to fully value avoided line losses, and indirect avoided transmission and distribution investments. This means that most of the additional benefit streams that could accrue to certain parties if there were ways to monetize the benefits would not be included in most utility cost-benefit analyses.

States such as Vermont and New York are considering location-specific benefits in their tests (these are discussed in the "Deferred Infrastructure Investment" section). In some Duke Energy service territories, a new CHP project determined to relieve particularly acute voltage issues or otherwise avoid major investment can benefit from a higher incentive from Duke, as there is some flexibility built into their incentive programs (Lawrence et al. 2012).

Cost and Lost Revenue Recovery

Utilities can usually recover the costs of their energy efficiency programs, but some utilities expressed concern that they do not always have 100% assurance they will be approved for the cost recovery they seek, so they see risk associated with having expectations of full cost recovery. And though cost recovery happens in most places, lost revenue recovery is a much more complex undertaking, and of great concern especially to utilities operating in decoupled states.

Utility fears about the risk of not recovering all the costs and lost revenues resulting from new CHP systems are not without cause. A major electric and gas utility in New York "ran into trouble" trying to recover what they perceived as lost revenue. The New York Public Service Commission did not agree with their estimate, which was perceived by some other utilities as sending a signal that deploying energy efficiency and expecting lost revenue recovery is "not a zero-risk proposition" (Ballam 2013).

In Massachusetts, as energy efficiency goals rise, spending on energy efficiency programs has risen as well. Indeed, utilities that had perceived efficiency as an optional service now view it as a core business unit. While parts of the utility are still concerned with selling kWh to customers, other parts are now consistently advocating for energy efficiency. Internally, that marks a significant shift over the last couple of years (Ballam 2013).

In Ohio, American Electric Power (AEP) can now count CHP savings towards its energy efficiency savings goals, and can thus recover the cost of CHP support through its energy efficiency rider (Williams 2012). The rider is designed to recover "program costs, fixed distribution costs and shared savings," though to date there appears to be little interest in using some of those rider funds to offer dedicated CHP incentives or programming (Butler and Wissman 2013).

For thirty years, Alliant Energy's *Shared Savings Program* in Wisconsin has helped customers cover the up-front cost of major capital investments, such as CHP, and then allowed them to pay back the effective loan over five years via charges on their monthly bills. Alliant earns the same rate of return on this energy efficiency program as it does all other investments that are considered during rate cases (ACEEE 2013; Adams 2013; Moorefield and Warren

2013). In 2013 Alliant managed $6 million in contracts in its Shared Savings program, down considerably from the program's "heyday," before the last recession. Customers using the Shared Savings program enjoy reduced bills during the five year period, and then significantly reduced bills after the first five years (Adams 2013).

PORTFOLIO STANDARDS AND CREDITS

A lot of attention has been paid in recent years to the manner in which CHP is valued and credited within energy efficiency resource standards (EERS), renewable portfolio standards (RPS), and other alternative energy portfolio standards (APS). These standards typically set some portion of a utility's load as a target to be met with eligible efficiency or renewable energy resources.

While CHP is technically not prevented from qualifying within most EERS, and most renewable fuel-powered CHP is eligible to meet RPS targets, the manner in which they are prioritized within the standards dramatically affects how valuable they are to CHP owners and utilities. Most states have relegated CHP to the bottom tier of any applicable standard (ACEEE 2013), meaning that in most cases, inclusion in a portfolio standard conveys little value to CHP owners or utilities compared to other resources.

In some states, waste heat recovery, or waste heat to power systems, are eligible resources within an RPS or EERS. Such policies offer credit to waste heat recovery components added to *existing* generation assets. A new CHP system does not qualify in these instances, because though it is using its waste heat for productive purposes, additional fuel is also being burned. Such a system usually only is credited for its efficiency benefits relative to other, more traditional energy resources, and then only in an EERS.

Ideally, an EERS or APS would maximize support for CHP by allowing natural gas-powered CHP to be eligible, allowing systems of all sizes to participate, and allowing the full suite of CHP technologies to participate. Standards that are binding, and thus include a penalty for failure to comply, confer actual benefit to CHP owners or owners of EERS or APS credits.

Portfolio standard credits generally derive their value from the cost that utilities pay to acquire the resources to meet the targets. For an APS or RPS, CHP-using facilities are issued a credit for their calculated energy contributions, which are then purchased by utilities to meet their targets. EERS generally establish an overall amount of efficiency that must be acquired, and utilities meet that through the effective administration of their energy efficiency portfolios of programs.

Utilities are incentivized to acquire resources that have value in the tradeable credit market or acquire resources that allow them to avoid the "stick" that they must pay if they do not acquire the appropriate amount of resources for the standard. This stick is usually an alternative compliance payment per MWh they must pay if they fail to meet the goals. The difference between the alternative compliance payment and the amount it will cost them to satisfy the standard is the economic incentive to acquire eligible resources or credits representing the resources.

Spotlight: Massachusetts

Massachusetts' APS is probably the best-known energy standard in the United States that is explicitly designed to encourage CHP.[10] The binding targets for utilities, which ramp up to 5% of system load by 2020, can be met with new 200kW or larger CHP as well as heat recovery or electricity generation added onto existing generation systems (Breger 2011). The standard also includes other technologies such as flywheel storage, but CHP dominates, representing 99.1% of the technologies acquired for compliance with the standard (MDOER 2012a).

To earn an Alternative Energy Credit (AEC) under Massachusetts's APS, a CHP system must perform efficiently enough that the total fuel consumed by the CHP system is less than that fuel that would have been consumed to produce the same thermal energy and grid-provided electricity absent the CHP system. The difference between those calculations, expressed in MWh, is the basis for the AECs, and 1MWh of saved fuel is equivalent to 1 AEC. Given the performance of an average efficiency CHP system, these credits are currently equivalent to about three cents per kWh to qualifying system owners. In some ways the state views this program as helping to subsidize operation and maintenance costs of the systems, since the value per kWh of credits will usually exceed what a system owner is typically spending for system operation and maintenance (Ballam 2013).

As with many other portfolio standards, the value of AECs are derived from the fact that annually, utilities must meet the APS-required percentage of load with alternative resources as expressed in Table 3. Utilities buy credits from brokers who have purchased them from agents representing individual owners of tradable AECs.[11] If utilities do not buy or otherwise acquire enough AECs to meet their annual obligation, they must make their alternative compliance payment, which in Massachusetts is a per-MWh cost for each MWh they fall short of their annual target. The current alternative compliance payment amount for the Massachusetts APS is $21.43 per MWh (NEPOOL 2013). These alternative compliance payments are collected by the Massachusetts Department of Energy Resources and used to fund additional development of alternative energy systems (MDOER 2012b).

The cost of purchasing AECs or making alternative compliance payments is recovered in rate cases, but utilities are economically incentivized to reduce the cost of satisfying the APS, by purchasing AECs for as little as possible and certainly below the alternative compliance payment amount. The price of an AEC — currently a few dollars below the alternative compliance payment — is designed to be lower than the alternative compliance payment so that utilities are encouraged to meet their APS obligations in a manner that provides direct financial support for the deployment of APS-supported technologies such as CHP (Ballam 2013, Breger 2011).

[10] See http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/ for documentation and performance information about Massachusetts' Alternative Energy Portfolio Standard.
[11] The NEPOOL GIS system converts statistics about a registered generator's performance into actual tradeable certificates applicable to New England's various energy portfolio standards. Independent meter readers take meter readings of generators, apply relevant formulas, and submit them to the GIS system to convert to tradeable AECs before they return to the generator owners as tradeable credits.

Additionally, AECs come with some attributes that, while not very lucrative at the moment, could be more lucrative in future policy scenarios. Environmental attributes, such as carbon dioxide emission reductions, are attached to AECs, as are the capacity of the savings for use in forward-capacity markets, discussed on page 48 of this report (Ballam 2013).

The role of CHP in Massachusetts' APS and energy efficiency portfolios continues to grow. Table 3 shows how the Massachusetts APS ramps up and how much CHP has been installed versus estimated during the program's first few years.

Table 3. Performance to Date of Massachusetts Alternative Energy Portfolio Standard

Year	APS Minimum Standard	Aggregate Estimated Installed CHP (MW)	Actual Installed CHP (MW)	Estimated Required Banked Total AECS (MWh)	Actual Banked Compliance CHP (MWh)
2009	1.00%			163,844	128,922
2010	1.50%	64		626,886	225,104
2011	2.00%	92	52	852,272	324,922
2012	2.50%	121		1,168,641	N/A
2013	3.00%	148		1,460,349	
2014	3.50%	177		1,771,544	
2015	3.75%	205		1,932,972	
2016	4.00%	215		2,086,473	
2017	4.25%	226			
2018	4.50%	237			
2019	4.75%	249			
2020	5.00%	261			

Sources: Breger 2011; MDOER 2012a, 2013b

Though the program is still young, it does appear that the trend thus far has been that less CHP has been installed and "banked" as AEC credits than was planned for. While these numbers have been impacted by the recent recession, it is clear that even in Massachusetts, a state viewed as extraordinarily supportive of CHP, more aggressive measures will likely have to be taken to meet CHP's full potential. Indeed, for the most recent year for which compliance data is available, 65% of the utilities' obligation was met through the purchase of alternative compliance payments (MDOER 2013b).

Despite the slow growth of AEC compliance projects, many CHP developers indicate that the presence of the APS market has made Massachusetts a more attractive place to do CHP business than most other states in the country. One developer believed that the combination of AECs and the aforementioned MassSave CHP incentives had been enough of an additional revenue stream to make two or three projects economic that would not have otherwise been. Another called the option to earn AECs "terrific" for the market.

While the benefits of tradeable credits usually confer most directly to CHP system owners, increased deployment due to portfolio standards can also yield indirect benefits for utilities.

CHP can indirectly help reduce the cost of satisfying renewable energy goals by reducing the load that is used to calculate each utility's RPS goal. The more CHP and energy efficiency they acquire in their system, the less it will cost them to satisfy the often more expensive renewable goals (SEEAction 2013).

Calculating Savings

The manner in which CHP savings are calculated for utility savings targets varies from state to state and portfolio standard to portfolio standard. CHP systems will provide new and consistent energy efficiency savings throughout their long lifespans. While calculating savings from CHP systems is not as straightforward as other energy efficiency measures, it is possible to re-measure and calculate savings from year to year, or for the duration of an efficiency program period, in order to ensure that savings from CHP systems are valued fairly for the entire time they continue to provide efficiency benefits.[12]

DEFERRED INFRASTRUCTURE INVESTMENTS

Targeted deployment of CHP and energy efficiency is one of the current opportunities being explored in states such as New York and Vermont (Jolly et al. 2012 and Eaton 2013). This is because well-implemented and designed CHP systems and other energy efficiency investments can actually reduce the specific peaks faced by areas of the distribution grid, mitigating the need for additional equipment to meet peak loads (Jolly 2013). CHP placed at specific locations can be remotely monitored to ensure it is operating at a certain level for a certain time period, reducing the strain on distribution assets during peak periods (Jolly et al. 2012).

In New York, Con Edison's Targeted DSM program specifically addresses customer-side demand reduction strategies, such as CHP, at areas of the utility's network most in need (Jolly et al. 2012). By reducing demand in specific areas, existing assets are more efficiently utilized and the utility avoids "overbuilt distribution assets" (Jolly et al. 2012). It has done this after years of experience seeing that "[energy efficiency] programs have reliably demonstrated a viable alternative to costly capital improvements" (Jolly et al. 2012).

Con Edison aims to avoid unnecessary investments in infrastructure by "re-examining the methods and associated costs of meeting load growth," including demand-side management, such as CHP, as an approach "to defer capital expenditures." Rather than rely on models observing just current and future traditional transmission and distribution assets, Con Edison now also incorporates potential customer-sited CHP in its transmission and distribution infrastructure modeling, forecasting their impact on individual customer loads during peak periods and the grid overall (Jolly et al. 2012).

Using this approach to modeling, Con Edison has deferred "multiple traditional [transmission] and [distribution] load-relief capital projects," yielding significant reductions in costs for the company itself and thus its customers (Jolly et al. 2012). It also avoids costly peak-time purchases of capacity on the capacity markets (Jolly 2013).

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[12] See Kolwey 2012 for a discussion of different models and considerations to take into account when developing an approach to valuing the electricity savings of a CHP system.

One example is the 7.5 MW CHP system installed at the New York Presbyterian Hospital (Jolly 2013). This system is deployed in an area where Con Edison expected to make significant upgrades in 2017. Instead, the existing CHP system offers Con Edison's system engineers access to real-time data via telemetry, and after over two years of data collection Con Edison can now "comfortably rely" on the system, and think of it as capable of offering 7 MW of load reduction at the local substation level if needed (Jolly 2013, Jolly et al. 2012). The collected CHP system data is incorporated into Con Edison's forecasts of future load constraints, and Con Edison anticipates relying on it to help reduce stress on the local distribution infrastructure during future peak load times (Jolly 2013; Jolly et al. 2012).

Con Edison also offers an "offset tariff" for facilities using CHP to power campus-like settings with multiple buildings and meters, such as hospitals and universities. This tariff allows the CHP generator output to be allocated on a daily basis across all meters, which effectively reflects the impact of the CHP system on the total campus' peak load (Jolly 2013; Plitch 2013). This is one way the utility is working to encourage CHP to help avoid or defer larger capital investments. The New York State Energy Research and Development Authority (NYSERDA) has helped augment the utility's targeted approach with additional incentives for distributed generation projects located in constrained areas. The state and utility worked together to map out the areas of the network that would require major investment in the next ten years. These areas guide NYSERDA in its offerings of additional incentives for targeted projects (Jolly 2013).

In Vermont, a new effort in 2007 began geographically targeting energy efficiency investments to particular areas of the distribution system, with the express purpose of avoiding or deferring new investments in system infrastructure (Eaton 2013). The initial effort was funded at $20.5 million, and it identified four specific geographically targeted (GT) areas for priority. An initial assessment found that about 32% of the state's largest businesses — those with total annual consumption of over 500 MWh — were located in GT areas (VEIC 2007; Eaton 2013).

With each new Efficiency Vermont program period, new GT areas have been identified, and others have been dropped as local conditions change. To select the GT areas, an external planning committee considers areas that will likely require upgrades within the following three to ten years. Utilities share information about particularly constrained distribution and transmission lines, and assessments of the cost-effectiveness of targeting new energy efficiency projects is considered. Targets for GT areas are expressed as MW, to address and mitigate seasonal peaks, but Efficiency Vermont also seeks to concurrently acquire MWh savings as part of its overall business structure.

The GT program offers Efficiency Vermont leeway to "get creative" and offer additional incentives on top of the traditional incentive offerings in GT areas (Eaton 2013). While kWh savings in GT areas may be more costly than kWh in the statewide energy efficiency portfolio as a whole, they are often far less expensive than the alternative, which would be costly infrastructure investments (Eaton 2013). Thus the benefits still outweigh the costs and the GT program provides ratepayers and society at large with an overall benefit.

Efficiency Vermont also keeps the GT areas in mind when thinking about future energy efficiency programming. For instance, if a certain technology or approach might require a small pilot program to determine how it performs, Efficiency Vermont might target the GT area to encourage greater savings there (Eaton 2013). At present only one CHP system is being considered within the GT program, but there is a framework to support and encourage additional CHP systems within GT areas if such a project makes sense (Ibid).

The initial evaluation of the impact of the first phase of the GT program found that "in aggregate, energy and demand savings are being achieved" for the system as a whole as a result of GT activities. The evaluation acknowledged that given the short time period observed (18 months) and a limited number of data points, determining precise savings at the feeder level was difficult (Navigant 2011). The program has not existed long enough to yield evaluations with accurate assessments of true avoided costs, but over time a more full assessment of the amount of infrastructure deferred or avoided may be possible.

Other policies can incorporate geographic targeting. California uses its feed-in-tariff (FIT) program to encourage CHP deployment in areas of the grid that are stressed or are likely to become stressed. A list of substations that are at or nearing a point of constraint is regularly updated, and customers signing FIT agreements are granted an additional payment per kWh for producing power in these areas (Lipman 2013b).

CUSTOMER RETENTION AND ECONOMIC DEVELOPMENT

CHP's economic benefits can be significant enough for certain customers that utilities can view some CHP projects as economic development efforts, helping to strengthen their customer base while ensuring that their service territory retains valuable high-load customers. In fact, some states view their CHP programs as primarily economic development programs (Bachmann 2013).

Philadelphia Gas Works (PGW), a publicly owned utility, offers a program to its customers that helps them pay for CHP systems on their bills and spread the capital costs of the system over five years (Youssef 2013). PGW borrows money at about 5% to pay the upfront cost for a CHP system, which is purchased from and installed by a 3rd party project developer. Ownership of the system is retained by the CHP host site, but PGW covers the cost for the customer. In return, the customer pays PGW a flat rate for five years, which covers the cost of the system, fuel costs, and the cost to PGW of borrowing. These monthly payments always amount to less than a customer was paying monthly to fuel and operate their older inefficient system and buy power from the grid, and so the customer continues to be able to pay for the new CHP system out of its operating budget and does not need to ask internally for additional funds.

PGW views this program as critical to economic development, customer retention, and the general "greening" of Philadelphia. PGW does not make any money on the program, but does offer a model that might still make economic sense for a customer even if a small profit margin was built in, as would likely be necessary for a for-profit utility. Its projects are generally seeing payback periods of 3.5 or 4 years, and are subject to no particular minimum or maximum size or cost. The largest project PGW has supported through this program was $35 million, and the smallest was several hundred thousand dollars (Yousseff 2013).

CHP offers a particular benefit to natural gas utilities that operate in regions that are seeing extensive expansion in the renewables sector. The EIA projects that about 31 GW of wind capacity and 19 GW of photovoltaic capacity will be added between 2010 and 2035 (EIA 2012a). With increased customer interest in "alternative" energy sources, there is room for natural gas utilities to market CHP as a modern, green, or high-tech resource, particularly in markets where renewables are expected to increase capacity enough to become important competitors. CHP's cost benefits over some renewable resources can be significant, especially for facilities with high thermal loads. Some utilities are recognizing the benefit of marketing CHP as an alternative to traditional "dirtier" generation. One natural gas utility official noted that CHP helps his company remain "relevant" in a time of rising interest in renewables.

Offering CHP services or electric service provided by CHP to data centers could also help certain utility service territories better attract data centers as a marketing scheme. Data centers are increasingly looking to their own generation in order to avoid power failures, and utilities that encourage the deployment of data center-sited CHP may have a competitive advantage over others.

Customer-sited CHP can also help customers comply with air regulations, and in Ohio, utilities and the public utility commission are targeting specific facilities impacted by new US EPA air regulations for a CHP pilot program designed in part to retain these industrial facilities and their important jobs (PUCO 2012).

For natural gas distribution companies, planning for natural gas extension projects off main gas lines could include assessments of potential for CHP projects. Including a new CHP project with a gas extension project could help make the project more economic, especially for the customer, who must share part of the cost of extending the needed gas main. Connecticut's Department of Energy and Environmental Protection suggests this exact planning approach for its natural gas utilities in its 2013 Energy Strategy (CDEEP 2013).

Finally, since natural gas utilities are well-positioned to benefit in the long term from greater deployment of CHP within their service territories, they may do well to tout their support of CHP as a competitive advantage over electric utilities. In Arizona, where the electric utilities do not explicitly support or offer incentives for CHP, Southwest Gas views its support for CHP as a way to acquire increasing market share of valuable high-load customers (Esparza 2013).

EMERGING VALUE OPPORTUNITIES

While there are significant ways that CHP system benefits can be monetized today, there are also a number of opportunities that may become more applicable as CHP owners explore them and policies and regulations change. To date CHP systems have participated in a minor way in the following markets and opportunities:

- Ancillary services markets;
- Resource planning activities;
- Environmental compliance actions;
- Transmission planning activities;

- Long-term capacity markets;
- Demand-response markets;
- System resiliency planning activities; and
- Utility sales of thermal energy.

If utilities could better leverage the benefit streams available to them in these markets and activities, CHP may become substantially more attractive to them in the future.

Ancillary Services Markets

Twenty years ago EPRI noted that in some situations, distributed generation can provide "other local area benefits that can be more significant than [transmission] and [distribution] investment savings" (EPRI 1993). The opportunity for this with CHP has only been minimally explored.

CHP systems have not been very active players in existing ancillary services markets, but utility ownership of CHP systems could change that. When CHP systems are owned by individual facilities, they are usually sized to meet onsite thermal needs, and the electricity generated is a welcome byproduct. However, if systems were built with the expectation that excess electric generating capacity could be valuable in ancillary services markets, these opportunities might make more sense (Kirby 2007).

Participating in ancillary services markets is a complicated activity, not least because the owner of a CHP generator may also be considering participation in energy markets, and must make very quick decisions about which markets to enter. Participation in ancillary services markets and demand response markets is generally mutually exclusive, for instance (Nyquist et al. 2013). Prices are volatile and it takes a high degree of sophistication to know how to play in these markets. Additionally, since only CHP systems that have substantial additional capacity for export can participate in many of these markets, participation in most ancillary services markets is necessarily limited to systems that are sized and built with the expectation of exporting power (SEEAction 2013).

Ancillary services markets continue to change and adapt to new realities and opportunities. FERC Order 755, issued in 2011, called for a revision of the rates to which providers of frequency regulation service are subject (FERC 2011b). This order is important to potential providers of frequency regulation service, such as a CHP resource, because it notes that in some cases the resources providing such services have been "compensated for their opportunity costs" in an "unduly discriminatory" manner. Additionally, the order addressed the fact that in some markets, resources that could "ramp-up" faster than others were not benefitting from higher payments for the frequency regulation service they provided (FERC 2011b). As transmission system operators develop their plans to implement the order, a more favorable payment structure could help make the economic case for certain CHP systems to act as applicable system resources.

At present, the few examples of CHP systems participating in ancillary services markets show there is money to be made. Princeton University is earning a total of about $600,000 per MW per year for its ability to rapidly respond to dispatch requests from operators of just one of PJM's multiple ancillary services markets (Nyquist et al. 2013).

The transmission markets of PJM, ERCOT, ISO-NE, CAISO and NYISO all have considered how CHP could play in their ancillary services markets. Certain markets, such as ERCOT, tend to pay higher prices for ancillary services than others, and others, such as PJM, are concurrently working on encouraging more CHP in other markets, such as capacity ones.

Resource Planning

Most states engage in some type of energy resource planning process. This planning process is often codified as an integrated resource plan, or IRP, which is a plan that lays out the forecasted energy supplies and demands of the state or utility service territory, and typically includes demand-side resources, such as energy efficiency. These plans vary in the extent to which they actually bind utilities to specific resource mixes, with some of them serving simply as guidance, and others establishing binding plans for which changes must be justified (SEEAction 2011).

According to PURPA, the definition of an IRP is:

> *…In the case of an electric utility, a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency,* ***cogeneration*** *and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity,* ***reliability****,* ***dispatchability****, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and* ***shall treat demand and supply resources on a consistent and integrated basis.*** (PURPA, emphasis added)

Despite the above definition, most states do not fully consider the potential role of CHP to meet future energy needs. Only a handful of states specifically require that all cost-effective energy efficiency be acquired before other resources, and of those, only two specifically identify CHP as a priority resource that must be maximized (within cost-effectiveness bounds). Massachusetts and Connecticut have specific and clearly defined requirements to assess the potential for CHP and to integrate it into IRPs as a priority resource (see Appendix I).

As a result of CHP's prioritized treatment in the IRP processes of those two states, utilities tasked with acquiring resources, including efficiency, must evaluate and consider the CHP potential during each new round of planning. By having IRP justification for their resource plans and thus cost recovery, utilities can view CHP more like other centralized resources in terms of earning a return on their investment.

Additionally, comprehensive resource planning can allow joint natural gas/electric utilities to better assess the overall impact CHP programming might have on all business areas. While anecdotally it appears that joint utilities are having more internal discussions about CHP's role in all their businesses, it is still often relegated to an energy efficiency program on one business side or the other (Noll et al. 2012).

Environmental Compliance Pathway

While mandated cap-and-trade programs are limited in the U.S, California's new cap-and-trade program for greenhouse gases is likely to confer some benefit in the future. Though a number of CHP developers have indicated problems with the program's specific methodology related to CHP, it is generally designed to confer economic benefit for reductions in greenhouse gases. Provided the methodology for counting reductions is improved to fully recognize the efficiency benefits of CHP, CHP should eventually be economically incentivized through the program (Miram et al. 2013).

Once the federal New Source Performance Standards are finalized for new power plants, Section 111(d) of the Clean Air Act directs the EPA to develop standards for existing power plants. As the EPA prepares to regulate carbon dioxide at existing power plants, the value of being able to use CHP to help meet such standards will increase for affected utilities. In the past, the EPA has endorsed the use of CHP as a compliance mechanism for some of its air rules, recognizing its important emissions benefits (EPA 2012, EPA 2000).

Additionally, utilities can market CHP directly to individual facilities as a compliance mechanism for regulations affecting them. For instance, in 2012 the EPA joined the U.S. Department of Energy to begin formalized assistance to facilities affected by the "Boiler MACT,"[13] including assessing them for the appropriateness of a new CHP system.[14] Utilities can incorporate such compliance benefits into their calculations of participant benefits

Transmission Planning

Several recent changes in the way regulated transmission assets are planned and paid for may further encourage CHP deployment. FERC Order 1000 now requires regional transmission organizations to consider state- and federal-level policies such as RPS and EERS standards when planning for new transmission assets. Additionally, Order 1000 requires neighboring transmission regions to "coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs" (FERC 2011a).

Order 1000 also establishes cost-allocation rules that provide for the implementation of an "interregional cost allocation method" for assets that might serve multiple transmission regions (FERC 2011a). Further, Order 1000 allows for the cost allocation to fund new assets to be spread among specific beneficiaries, and for region-specific methods of cost allocation to be developed to meet regional needs (FERC 2013).

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[13] See http://www.epa.gov/chp/documents/boiler_opportunity.pdf for specific details of the opportunity for CHP in the Boiler MACT rule

[14] See http://www1.eere.energy.gov/manufacturing/distributedenergy/boilermact.html for specific details of this assistance program

Order 1000 also sets the stage for cost-effective resources that are not necessarily new transmission assets to be used to meet transmission needs. In fact, Order 1000 allows stakeholders "to demonstrate that [energy efficiency] is a cost-effective and reliable alternative resource that can postpone, possible indefinitely, the need for expensive transmission upgrades and new generation" (Lyle et al. 2012). Non-transmission alternatives (NTAs) such as energy efficiency could reduce the need to make new transmission investments, providing long-term economic benefits to customers. Order 1000 delineates a framework for transmission utilities to pay for these types of alternative assets by spreading the cost among those customers that would benefit from the particular NTAs (Lyle et al. 2012; FERC 2013; NRG 2010).

CHP could very well be considered a cost-effective NTA, and transmission organizations that consider NTAs during the planning process could use a number of estimates of CHP potential (such as those in IRPs, or planned within energy efficiency program budgets) to ascertain what a reasonable level of reliable CHP capacity might be (NESCOE 2012).

There is an emerging opportunity to include CHP and other energy efficiency resources in long-term planning processes, including those for regional transmissions markets. As noted by Lyle et al. 2012, the New England ISO has become more aggressive in including realistic energy efficiency resources in its long term planning processes (Lyle et al. 2012). By consistently reviewing the performance of fully funded energy efficiency programs, ISO-NE can update its plans and begin to encourage the deployment of NTAs in geographies that have particular transmission constraints.

The New York ISO offers one example of how to encourage NTAs in the form of energy efficiency. The ISO's Reliability Needs Assessment considers both transmission and resource adequacy needs for a ten year time horizon, and asks market players to come up with solutions that would meet those needs. These solutions can comprise energy efficiency resources, and, furthermore, can be funded through a cost recovery process similar to that of "traditional transmission solutions" (Lyle et al. 2012).

The context exists, at least in certain regions, for CHP to be considered as both a generation and transmission resource in certain planning activities and in certain applications. However, considerations of appropriate energy resources and transmission plans are often conducted along different time frames, and with vastly different assumptions about how and whether energy efficiency resources and NTAs will actually be deployed.[15] A concerted effort to better harmonize these planning processes with regard to energy efficiency resources such as CHP will be needed to give utilities a better sense of how these resources will be valued.

Long-Term Capacity Markets

Markets for future generation capacity have begun to open up to energy efficiency in the PJM and ISO-NE territories. These forward capacity markets, or FCMs, are generally structured not to distinguish between one resource and another, but simply allow owners to bid in resources that will provide future capacity (Ballam 2013).

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[15] See Lyle et al. 2012 for an example of this challenge in New England.

Beginning in 2006, the Vermont Energy Investment Corporation (VEIC) began filing claims for energy efficiency-caused capacity reductions in the ISO-NE FCM. In 2008 VEIC bid in 50MW of reduction out of VEIC's total energy efficiency portfolio, at a "floor price" of $4.50 per Kw-month, yielding a payment of $225,000 per month to VEIC (Jenkins et al. 2008).

At present efficiency resources are always aggregated by third parties, making it difficult to know exactly where and how CHP is playing in these markets. If CHP were to rise to represent a larger percentage of the capacity market, that could change, and the clear value proposition for CHP in those markets might be more clear (Ballam 2013; Langbein 2013).

Capacity markets are by their nature forward-looking, and existing CHP systems are not likely designed to be able to offer additional capacity services for any duration of time. Therefore, existing CHP systems may not be well suited to take advantage of the growing trend of treating energy efficiency resources like other resources in capacity markets (Langbein 2013). Capacity markets are not signal based; resources are bid in well before they are needed, and are integrated into system planning. In this way, future CHP systems could potentially be designed with an expectation of participating in capacity markets, and that excess capacity could be bid into forward capacity markets for additional future economic benefit.

Demand Response Markets

Demand response actions are those taken by an energy user to curtail their energy demand and consumption at a specific time in response to price signals, such as time-of-use rates or demand response incentives. It makes little difference to system operators how the demand response reductions are accomplished, and ramping up an on-site generator to meet more of a facility's demand could yield a demand response-type load reduction from the point of view of the system operator (Langbein 2012).

Demand response markets can be lucrative, and are growing. Revenue generated from participation in PJM's demand response market topped $450,000,000 in 2010 and 2011. In 2010, the demand response market for actual energy was yielding prices of about $30 - $40/MWh in the PJM territory (Langbein 2012).

One lumber mill participating in the ISO-NE demand response market earns about $40,000 a year by using its 2MW CHP plant to generate energy during the region's hottest days of the year. The hottest days of the year happen to be when the ISO-NE grid is the most stressed, and also the days where running the mill at full capacity is miserable for workers. The mill decided that ramping down production on those days would reduce worker discomfort in addition to providing a valuable revenue stream (EnerNOC 2011).

The major reason demand response markets are increasing in total size is FERC Order 745. Issued in 2011, the order instructs operators of demand response markets to begin paying the full locational marginal price for power to demand response resources, instead of the lower prices that had been previously paid in some markets. This order has significantly increased the economic viability of certain demand response resources, including those that result from on-site generation, and has substantially raised the size of the demand response market in PJM, operator of the nation's largest demand response market (Tweed 2013;

Webster 2013; FERC 2011c). Order 745 is seen as a strong statement that FERC believes load can act just like generation (Webster 2013).

Demand response markets appear to be especially well suited to larger sets of buildings that rely on CHP. Princeton University is often cited as an example of how a large campus with multiple buildings can control is CHP system production to respond to market conditions and enjoy additional economic benefits beyond those derived solely from its increased energy efficiency. In response to FERC Order 745, Princeton entered into an arrangement with PJM Interconnection to allow for a full "automated bidding, dispatch, and settlement process," during demand response events. Over a four month period the university earned a $350,000 payment for its demand response services. Princeton estimates that by participating in both the ancillary services market and the demand response market, it saves an additional $1 million each year (Nyquist et al. 2013).

In the ISO-NE market, a temporary and somewhat limited demand response program in response to FERC 745 is in place while a more permanent system is developed "to fully integrate FERC 745 into market operations." The Massachusetts Institute of Technology also engaged in an arrangement with ISO-NE to allow direct dispatch, including its CHP system, and earned $100,000 in payments over a four month period (Nyquist et al. 2013).

In some ways, designing CHP systems to act more like traditional grid resources will require a shift in the way facility managers think about their in-house resources. "People get really freaked out to see their equipment ramp up and down in response to a signal," says Michael Webster, who founded a company that helps CHP owners better manage their systems and take advantage of external markets (Webster 2013). For utilities to view customer-sited CHP as a generation or distribution resource, they will increasingly rely on intelligent controls to allow them to directly control its operations. Facilities that wish to benefit from having CHP on site will need to get comfortable with such situations.

System Resiliency Planning

Since hurricanes Katrina and Sandy revealed the resiliency of CHP during times of extreme weather, certain states that may be particular affected by storms and floods have begun to call out CHP specifically for its reliability powering critical pieces of infrastructure. Texas and Louisiana both have implemented policies requiring buildings deemed "critical" to be assessed for the feasibility of CHP when being designed or significantly upgraded (Chittum 2012). These policies are fairly new — Louisiana's became law in late 2012 — and so their market impact is not fully known, but it is clear that public buildings will be placing a premium on on-site power supplies supported by CHP.

It is clear that emergency management planners are beginning to consider CHP for its resiliency benefits in a more concentrated manner than before. Some stakeholders have been pushing for states to leverage the increased attention insurance companies are paying to the devastating effects of climate change by requesting that insurance premiums consider the extent to which a building may have climate change adaptation abilities built in via CHP or other resilient technologies. In New York City, the Mayor's Resiliency Task Force developed 33 recommendations to improve the resiliency of the city's buildings in the face of Sandy-like weather events. These recommendations specifically include the promotion of CHP, and the removal of barriers to CHP so that New York City buildings can better enjoy the resiliency benefits provided by CHP (Urban Green 2013).

One interesting post-Sandy development is the discussion among CHP stakeholders in the northeast U.S. of a "Resiliency Portfolio Standard." Such a standard, which could ascribe benefit to CHP systems located above the point at which flooding might occur or able to immediately begin operating in island mode, could be added onto existing RPS legislation (Pentland 2013b). In theory such a standard could be articulated specifically for each state's particular weather- and natural disaster-related challenges, such as earthquake-resistant CHP systems and related infrastructure along the Pacific coast.

Thermal Energy Sales

One example of tapping into CHP revenue streams comes from Germany, where selling CHP-produced thermal energy into existing district energy systems is what is making new municipality-owned power plants profitable. The power plants will be able to remain highly profitable even while running in "part-load operation," as sales related to heat output outweigh losses of electricity sales. These municipal utilities are showing that increasing generation efficiency with utility-scale CHP — one planned CHP system in Dusseldorf is to be an immense 595 MW — can help make otherwise negligible power plant profits much more significant (Gas to Power 2012).

Utilities that own CHP systems could enjoy the electric benefits while choosing a strategy for use of the thermal energy that best serves their needs (Rouse 2013). The sale of electricity and benefits of the improved grid stability might constitute an ample revenue source for an electric utility, and giving away the thermal energy or selling it at a discount could be a way to attract customers that need the thermal energy and would have otherwise invested in a boiler themselves.

Moving Forward

Utilities are expressing increasing interest in including CHP in their efficiency or generation portfolios. However, as seen in the baby steps taken by one of the largest investor-owned utilities in the United States, utilities have yet to be convinced that CHP is in their economic interest. Utilities that have little experience with CHP will require substantial exploratory discussions with potential large commercial and industrial end-users first, to understand exactly how a CHP system installed at a long-time customer facility would impact the utility's physical systems and their finances.

These tentative steps make sense, especially in the conservative utility industry. However, approaching CHP so cautiously will likely leave much of the existing CHP potential on the table. To better encourage utilities to embrace CHP now, policymakers and regulators could improve policies and regulations that will result in utilities developing dedicated CHP strategies.

SUGGESTED POLICY AND PROGRAMMATIC DIRECTIONS

Several near-term changes could be made now that would help CHP systems be viewed more holistically for their economic benefits. Utilities and policymakers have many opportunities to encourage utilities to better integrate CHP into their operations and enjoy the benefits CHP provides.

Policymakers and regulators could:

- Host state- or utility territory-specific roundtables or dialogues on how to identify and value some of the benefits described in this report;
- Establish an EERS and/or APS portfolio standard in all states, and clearly treat cost-effective CHP (powered by all fuels) as a priority resource in utility plans to meet these goals;
- Allow generation-owning utilities to earn a return on CHP investment similar to that which they are allowed on centralized generation assets;
- Encourage heat planning and thermal mapping, perhaps within larger energy resource planning activities, to help utilities identify areas of their service territories that might be particularly well-suited to CHP as excellent thermal hosts;
- Encourage electric distribution utilities to develop unregulated subsidiaries that can own CHP assets, and codify allowable ownership structures by state law;
- Allow CHP to generate compliance credits in any program designed to control CO_2 emissions from existing fossil fuel-fired power plants under the federal *Clean Air Act*, and allow CHP supply to offset other state or regional greenhouse gas control programs; and
- Open new dockets to consider existing standby rate charges and ensure that they appropriately reflected the identified benefits to the grid.

Utilities could:

- More accurately measure and forecast the cost of line losses and incorporate the additional losses into the marginal cost of power when determining the costs and benefits of strategically placed CHP systems;
- Consider strategically-placed CHP as a distribution asset and assess its distribution system benefits when undertaking distribution plans and cost-benefit analyses; and
- Include all of CHP's additional non-energy benefits in the cost-benefit tests used for energy efficiency portfolios and energy resource plans.

CONSIDERATIONS AND QUESTIONS

There are a number of existing conflicts that must be addressed before utilities will view CHP as an economic opportunity. These include:

Concerns about competition. In deregulated states, distribution utilities are generally not allowed to own generation resources. If such utilities explore the option of using CHP as a distribution asset, to what extent might that crowd out 3rd party developers? Distribution utilities would likely have an advantage over these developers because the utilities are aware of customer loads and needs, constrained load pockets, etc. Are there ways to construct programs and agreements that still encourage healthy competition in these markets?

Concerns about rate impacts. Where utilities enjoy the benefits of CHP system-wide, it may be difficult for certain customers situated far from an actual CHP system to understand how they can directly benefit from the distribution benefits and improved efficiency benefits it offers system-wide. Before asking such customers to pay (via rates) for such investments, utilities should consider it their responsibility to educate consumer advocate groups on how such benefits will really be felt and experienced by customers that may only be benefitting from CHP's indirect benefits (NRECA 2007).

Counting CHP savings. As noted earlier, there are many ways that electric and natural gas utilities could count CHP savings as part of an energy efficiency portfolio. There is currently no consensus among stakeholders. Regional differences in power pools complicate this, and utilities appear to be waiting in some cases until a clearer consensus is established. The answer will have immediate ramifications for energy efficiency resource planning, but could have even greater long-term ramifications as utilities look to quantify the emissions impacts of their energy efficiency programming and use the emission reductions to help comply with air regulations. Appropriate evaluation, measurement, and verification of CHP savings during the entire system lifetime will be required.

Natural gas rate structures. As interest in natural gas energy efficiency opportunities grows, more states are looking to decouple natural gas rates from total sales, helping to encourage energy efficiency programs that seek to reduce customer gas consumption. While these decoupling mechanisms are beneficial to most energy efficiency goals, they do little to encourage CHP, and may actually discourage CHP, since CHP can increase natural gas consumption for CHP-using customers. Notably, larger natural gas customers, such as those that may be best suited for CHP, are often still on volumetric natural gas rates, even if decoupled natural gas rates exist for other customer classes (Noll et al. 2012).

Fuel-switching and natural gas efficiency. Some states prevent incentive dollars from encouraging fuel switching. Some CHP opportunities are viewed as fuel switching, and better education of state public utility commissioners and other policy makers will be necessary to support some types of CHP programming. Additionally, natural gas efficiency programs are often structured to encourage only activities which reduce natural gas consumption. By considering the impacts of CHP more holistically, policymakers would find reasons to encourage certain natural gas efficiency programs that might increase site-specific natural gas consumption, but decrease emissions system-wide.

Challenges of dynamic assets. One major policy issue that needs to be addressed in the United States is the extent to which CHP projects are more beneficial when designed and run as traditional generation assets versus when they are designed to be more flexible assets, able to dynamically respond to grid characteristics and able to play in emerging markets for various services. While CHP with greater flexibility could help support policy goals like increased renewable energy resources and reduced capacity constraints, the operation patterns of such CHP systems may yield reductions in their generation efficiency or increased needs for maintenance. Utilities and stakeholders will need a clear framework for engaging in discussions of the tradeoffs of these different operating models. Sometimes such tradeoffs will not be necessary, but it is important to know when they might be

(Webster 2013). Importantly, new control systems allowing more intelligent dispatch are helping to mitigate the need to choose between these benefits.

Conclusion

Greater utility investment in CHP is not a clear-cut opportunity. With CHP, utilities face economic choices that are often at odds with other policy or societal goals.

Existing policies and regulations tend to highlight and give credit for the benefits CHP conveys to individual system owners. CHP systems confer even more benefit to the grid they are connected to. These include efficiency benefits, avoided line losses, emissions benefits, reliability benefits, avoided transmissions and distribution investments, power quality and capacity services, and enhanced revenue opportunities for certain utilities. These benefits in turn serve all ratepayers as well as society at large, in the form of reduced emissions, reduced costs, and enhanced system resiliency. Policies and regulations are not currently well-structured to help utilities fully realize these benefits and spread them amongst all system users.

While utilities are well-suited to support the deployment of CHP, they are currently not generally economically incentivized to do so. Changes to the business structure and enhancements of market mechanisms that allows CHP benefits to be monetized could help encourage utilities to make the investments in CHP that will benefit them, their shareholders, and the general economy.

In particular, utilities do not view investments in CHP with the same eye they do investments in more traditional generation, distribution, and transmission assets. Utilities are a natural monopoly, especially in their distribution and transmission infrastructure, and so typical market forces do not apply the same way they might in other industries. State-level regulation largely dictates the extent to which utilities can earn a return on particular types of investments, and so they are thus bound to work within the constraints set by state regulators.

While some states are finding ways to open up these revenue streams for CHP owners and developers, most are not. Policy changes and effective outreach on some of these issues may be necessary to move the market, especially utilities, towards a view that CHP is as economically advantageous as other energy resources.

There are some important examples of utilities finding value in CHP and thus becoming instrumental in moving forward the local CHP market. The opportunities for more utilities to do this are immense, and energy efficiency advocates and those concerned with reducing emissions associated with energy production would do well to do everything possible to help utilities find value in CHP. However, as utilities begin to enter the CHP market in a more focused fashion, it will be important to ensure that risks and rewards of hosting and investing in CHP systems are fairly distributed among all parties.

The benefits of highly increased levels of CHP deployment are too great to ignore. It is imperative that we dramatically accelerate the level of CHP project development, to meet the new goal of 40 GW of additional CHP, but also to reduce the harmful emissions the electric sector currently produces. As ratepayers are being asked around the country to pay higher and higher rates, it is unfair to all that some of the most cost-effective energy infrastructure available today is rarely being deployed.

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Appendix I: Policy Language and Program Design

RATEPAYER FUNDED UTILITY-ACQUIRED DISTRIBUTED GENERATION

Ontario

The ministerial rules governing the Ontario Power Authority's CHP Standard Offer Program require that CHP acquired through the program must be considered for:

- Its cost-effectiveness;
- The degree to which "the project can be accommodated by local distribution systems and whether there are local benefits associated with the project";
- How well the CHP project meets the and is appropriately sized for the local "heat load requirements";
- "Contract terms reflect a reasonable cost for Ontario electricity consumers and a reasonable balance of risk and reward between project proponents and Ontario electricity customers" (Duguid 2010).

Ohio

Distribution utilities in Ohio can technically own generation resources, though there are currently no proposals from distribution utilities to do so (see ORC 2008). In order to get investment in a new generation resource approved within the stipulation, a strict determination of the utility's need must be conducted. A non-bypassable rider will need to be approved for all customers (Butler and Wissman 2013).

New Jersey

Details on New Jersey's Solar 4 All Program can be found here: http://www.njcleanenergy.com/files/file/Utilities/3-20-13-2B.pdf (NJBPU 2013).

CHP IN GENERATION, DISTRIBUTION, AND TRANSMISSION PLANNING ACTIVITIES

The State & Local Energy Efficiency Action Network offers some guidance on best practices for including energy efficiency in long term resource plans. These include evaluating a variety of energy efficiency forecasts, evaluating resources from a regional perspective, and considering the merits of energy efficiency in light of whether the energy efficiency resource can meet customer demands at a cost that is less than supply-side resources (SEEAction 2011). The following are specific examples of goals, targets, or consideration of CHP within planning activities.

New Jersey

The performance of CHP systems in New Jersey during Superstorm Sandy helped underscore the importance of reaching the goal of 1,500 MW of new CHP in the state, as codified in the state's 2011 Energy Master Plan (NJEMP 2011).

Connecticut

Connecticut offers a very clear example of how to explicitly treat CHP within utilities' long term resource plans. A 2007 Act required, and a 2013 Act updated:

> *The electric distribution companies, in consultation with the Connecticut Energy Advisory Board, established pursuant to section 16a-3 of the general statutes, as amended by this act, shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.*

These procurement plans are to consider customers' "energy and capacity requirements" looking out three, five, and ten years. They also are to be updated annually and funded through the state's systems benefits charge (Connecticut Public Act 2007). In 2011 this language was updated to explicitly frame these procurement plans as integrated resource plans (Connecticut Public Act 2011, Connecticut Public Act 2013).

New York

Con Edison incorporates energy efficiency into its distribution and transmission planning activities, based on its long-standing belief that "energy efficiency programs have reliably demonstrated a viable alternative to costly capital improvements" (Jolly et al. 2012). This approach has also fostered a more collaborative framework among the electric, gas, and steam arms of the company, allowing the three divisions "to strategize the revenue and infrastructure implications of [distributed generation] adoption" (Jolly et al. 2012).

In addition to the special attention Con Edison is paying to targeted distributed generation opportunities, the New York State Energy Research and Development Authority is also providing additional incentives for targeted projects that help avoid distribution and transmission costs (Jolly 2013). The utility and state worked together to map out the areas of network that would need investment in the next ten years to determine the areas eligible for the additional incentive (Jolly 2013).

Per Jolly et al. 2012, Con Edison compares the cost of new customer-side demand reductions, such as CHP, with the marginal cost of the "traditional utility infrastructure" that would be avoided by the new CHP investment. Specific aspects of the CHP system that would be considered when determining whether it could offer "reliable load reduction" include:

- Area substation contingency design criteria;
- Information from specific [distributed generation] units;
- Baseloaded output (kW) of each [distributed generation] unit;
- Historical weekday outage rate and daily 24-hour output of each [distributed generation] unit during the summer period—June, July and August; and
- Telemetry such as [distributed generation] breaker status, kW and kVAR, to monitor [distributed generation] performance including time of peak output coincident with the substation peak loads (Jolly et al. 2012).

Con Edison also offers an "offset" tariff to campuses with multiple buildings and a CHP system. The CHP output is applied to the total demand from all the campus meters, allowing the CHP system output to be credited against the entire campus' peak demand. In this way, individual meter peaks are somewhat minimized, and demand charges are reduced for the customer as a whole (Jolly 2013). The tariff was a result of a request by customers, and was initially considered as part of a working collaborative that existed outside of any active docket (Jolly 2013).

Ohio

In Ohio, utilities must report annually on the status and condition of generation, distribution, and transmission assets looking forward three years (see OAC 2009 and Wissman 2012). These reports must discuss issues pertinent to overall power quality and system reliability such as "service interruptions" in the past year and identify the causes; the ten most congested transmission facilities; and the condition of distribution facilities (OAC 2009). Though these reports do not specifically require identification of areas in which CHP could help avoid new investments in assets, they could help identify areas of the grid where CHP could be more beneficial than others.

Vermont

Vermont's Geographic Targeting (GT) scheme identifies areas of the grid that are constrained and are slated for some upgrade in the next three to ten years (Eaton 2013). The program is specifically designed to encourage energy efficiency investments that will help defer or avoid completely major infrastructure investments (Eaton 2013; Navigant 2011). The Vermont System Planning Committee makes annual recommendations to the Vermont Public Service Board, and after an initial assessment of GT areas is conducted, a smaller number is selected for more in-depth review (Eaton 2013).

See (Navigant 2011) for an in-depth evaluation of the process by which the GT areas were selected and targeted during the first phase of Vermont's GT program. Additional analysis of the impact of GT investments is warranted, and the evaluation offers guidance for determining the true impact of GT investments over time:

> *Further, the…scope of this study was limited to an 18 month period. Studying the effects of GT at the feeder level over a longer period may produce more conclusive observations, recognizing that a longer time period also allows for other factors such as customer migration and the economy to impact feeder loads. Accordingly, the best course of action maybe to begin GT programs in a constrained area far enough in advance of the need date (e.g., 5 years at minimum) and track loads annually to assess the combined effect that GT and non-GT actors have on the feeders (without trying to disaggregate these effects) and adjust plans for T&D upgrades accordingly.* (Navigant 2011)

Rhode Island

In 2012 Rhode Island adopted H. 8233, which explicitly requires affected utilities to:

> *…support the installation and investment in clean and efficient combined heat and power installations at commercial, institutional, municipal, and industrial facilities. This support*

> *shall be documented annually in the electric distribution company's energy efficiency program plans.*

and further that:

> *The energy efficiency annual plan shall include, but not be limited to, a plan for identifying and recruiting qualified combined heat and power projects, incentive levels, contract terms and guidelines, and achievable megawatt targets for investments in combined heat and power systems.* (RI GA 2012)

This activity is required under the auspices of system reliability and least-cost procurement frameworks, and impacts the state's regulated distribution utilities.

PacifiCorp Service Territories

PacifiCorp includes CHP in its IRP activities, and identified a need for a new market analysis of CHP in PacifiCorp territories in its most recent IRP, which also assumes 1MW of new CHP each year through 2032 (PacifiCorp 2013).

STANDBY AND BACKUP POWER RATE GUIDANCE

Connecticut

Several statutes clearly delineate the manner in which distributed generation projects, including CHP projects, should be treated with regard to backup and standby power rates. This treatment is a response to congestion issues in the transmission system in Connecticut, and the fact that parts of Connecticut cannot be fully served by local in-state resources.

For instance, Connecticut General Assembly Statutes Sec. 16-243o says:

> *Waiver of back-up power rates. (a) If a customer of an electric distribution company implements customer-side distributed resource capacity after January 1, 2006, and such capacity is less than the customer's maximum metered peak load, the customer shall not be required to pay back-up power rates if the customer's distributed resources are available during system peak periods, provided the customer shall continue to be required to pay otherwise applicable charges for electricity provided by the electric distribution company.*
>
> *(b) The costs that a customer is not required to pay pursuant to subsection (a) of this section shall be recoverable through federally mandated congestion charges by the electric distribution companies.* (Connecticut General Assembly Statutes 2013a)

This language is significant in that it clarifies that a customer may buy backup power at its standard rate for electric power. CHP projects in other states can be subject to backup power rates that are more punitive than the CHP customer's standard rate for service. It also provides a clear mechanism to compensate distribution utilities for this practice, namely: tapping into the congestion charges that Connecticut's utilities collect from customers to help fund the continued presence and operation of backup and "peaker" resources in the state for times when the in-state electric generating resources are not sufficient enough to meet in-state needs. This policy appears to have mitigated much of the concern about backup power charges for CHP systems in Connecticut (Lucchina 2013).

Additional, a new 2013 law (Connecticut Public Act No. 13-298) updates many of the statutes previously addressing Connecticut's energy plans. Importantly, this Act established a pilot program for large-scale (up to 20 MW) CHP systems. Projects participating in the pilot program are to be charged for backup power only to the extent they actually use the power, and not at all if the outage is less than three hours in length:

> *If a qualifying project that participates in the pilot program has an outage of service, the only demand charge that shall be assessed by an electric distribution company shall be based on daily demand pricing prorated from standard monthly rates, provided, however, that if the outage of service lasts for less than three hours, no demand charge shall be assessed by an electric distribution company.* (Connecticut Public Act No. 13-298).

New Jersey

A 2012 bill directed the New Jersey Board of Public Utilities (BPU) to:

> *…conduct a study to determine the effects of distributed generation upon energy supply and demand and determine whether distributed generation contributes to any cost savings for electric public utilities.* (see NJSA 2012)

The bill required the BPU to subsequently "establish criteria for fixing rates" that were identified as requiring a fix during the above assessment.

After the law was enacted, the BPU undertook a study and found that more information was needed before rendering a fully developed opinion. The BPU recognized the need for distribution utilities to recover their costs associated with providing standby power, but further:

> *…the rates that distributed generators pay [for] standby service should reflect the costs that they place on the [distribution utility]'s distribution system, to ensure there is equity between Distributed Generators and other utility ratepayers to avoid subsidies.*

Despite the need for more information, the BPU did direct each of the affected utilities to file information in support of their existing standby rates, or to file for new standby rates that consider, among other things, the actual performance of CHP systems "during peak electric demand periods," which could well improve the understanding a system's impact and benefits during peak demand periods (NJBPU 2012).

NATURAL GAS INCENTIVES AND COST RECOVERY

Arizona

In Arizona a 2011 ruling found that the traditional manner in which natural gas utilities viewed their revenue opportunities yielded little economic incentive for them to pursue energy efficiency, since revenues were directly tied to the sale of gas. The ruling thus allows natural gas utilities to file tariffs that offer reasonable recovery of the costs of meeting the new energy efficiency goals. Natural gas utilities are explicitly allowed to include CHP in their energy efficiency programs and cost recovery requests (AAR 2011).

Southwest Gas has done this, offering an incentive program of $400-$500/kW for CHP systems installed at customer facilities (Brinker 2013; Esparza 2013). The program is a small part of the utility's demand-side management programming, which allows the utility to earn cost recovery as it does with its other energy efficiency programming. Though specific CHP projects may result in an increase in natural gas consumption, the Arizona Corporation Commission approved the program after considering the system-wide benefits of CHP and the fact that increased CHP may decrease overall natural gas consumption at the point of electricity generation (AZCC 2007).

Connecticut

By statute, Connecticut natural gas distribution companies must offer rebates to customers purchasing natural gas to fuel distributed generation projects, including CHP, equivalent to their delivery charges. Connecticut General Assembly Statute Section 16-243l states:

Sec. 16-243l. Rebate for customer-side distributed resource projects that use natural gas. On or before January 1, 2006, each electric distribution company shall institute a program to rebate to its customers with projects that use natural gas, which projects are customer-side distributed resources, as defined in section 16-1, an amount equivalent to the customer's retail delivery charge for transporting natural gas from the customer's local gas company to such customer's project of customer-side distributed resources. Costs of such a rebate shall be recoverable by the electric distribution company from the federally mandated congestion charges, as defined in section 16-1… (Connecticut General Assembly Statutes 2013b).

Oregon

Oregon recently adopted legislation allowing the development of a voluntary emissions reduction program for the state's natural gas utilities. Utility-led energy efficiency projects that offer emissions benefits will be evaluated for their cost per ton of reduced emissions, and costs for the projects can be recovered from the ratepayers identified as benefitting from the projects. Projects that increase site gas use, but reduce overall emissions by avoided centralized generation, will be considered. Cost recovery can be structured in a manner to offer a certain return on investment, subject to regulatory commission approval (Oregon Legislative Assembly 2013; Krumenauer 2013).

Pennsylvania

Philadelphia Gas Works (PGW) supports the deployment of CHP and other capital-intensive energy efficiency upgrades through a program that covers the up-front capital cost for customers that purchase a CHP system directly from a third party. In exchange, the customer pays PGW a flat monthly payment over five years. While this amount yields cost-recovery for PGW, it is less than what the customer had been paying for separate generation and purchase of thermal and electric energy (Youssef 2013). In this way, a customer enjoys the new capital equipment and service but pays for it through its existing operating budget.

COUNTING CHP SAVINGS IN PORTFOLIO STANDARDS

Ohio

> *For a waste energy recovery or combined heat and power system, the savings shall be as estimated by the public utilities commission… For purposes of a waste energy recovery or combined heat and power system, an electric distribution utility shall not apply more than the total annual percentage of the electric distribution utility's industrial-customer load, relative to the electric distribution utility's total load, to the annual energy savings requirement.* (OSB 315 2013).

Ohio's Senate Bill 315 explicitly allows CHP to count towards its energy efficiency resource standard. The state is currently working through a lengthy process to determine how CHP savings will specifically be counted toward each utility's overall energy savings target (Butler and Wissman 2013). Until there is certainty in the manner in which CHP will be counted, the regulated utilities of Ohio appear reluctant to propose specific CHP programs within their energy efficiency portfolios (Ibid). One thing Ohio is doing well, though, is considering the various existing methodologies for counting CHP savings, and reviewing how different states' approaches have worked in practice. For more information on Ohio's ongoing efforts to develop a clear accounting methodology, visit the Public Utility Commission of Ohio's CHP page: http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/combined-heat-and-power-in-ohio/

Massachusetts

Details on how Massachusetts calculates alternative energy credits for its CHP systems can be found here: http://www.uschpa.org/files/Conferences-Presentations/Spring%20CHP%20Forum%202011/Breger_MA%20CHP%20Policies%20-%20USCHPA%20Spring%20Forum%20Wash%20DC%20050511%20DSB.pdf.

See also Kolwey 2012 for additional discussion of approaches to calculating CHP savings within a portfolio standard.

CALCULATING ADDITIONAL BENEFITS

New Jersey

New Jersey's Board of Public Utilities' Clean Energy Council maintains a Combined Heat & Power / Fuel Cell Working Group, which meets regularly to discuss future New Jersey policy issues pertaining to CHP (NJCE 2013). Recent discussions have focused on how to calculate costs avoided by installed CHP, and how to structure a long-term financing mechanism for CHP in the state. Presentations from past gatherings of the working group can be viewed here: http://www.njcleanenergy.com/main/clean-energy-council-committees/chp/archive.

Appendix II: Selected State Regulatory Summaries

	Utility Regulation	Active Electric Decoupling	CHP in EERS	CHP in Electric EE Programs	CHP in Natural Gas EE Programs	Shareholder Incentives for EE
Alaska	Fully regulated	No	N/A	No	No	No
Arizona	Fully regulated	No	Yes, counts as EE resource	No	Yes	Yes
California	Partially regulated	Yes	Separate CHP goals for utilities	Yes	No	Yes
Connecticut	Deregulated	Decoupled	Class III RPS resource	In state EE programs		Yes, but not for CHP
Hawaii	Fully regulated	Decoupled	Energy efficiency included in RPS	Yes		No
Iowa	Fully regulated	No	No			No
Maine	Deregulated	No	CHP in RPS	No		Not in place; allowed
Maryland	Deregulated	Yes	WHP is Tier 1 Resource in RPS	Yes		Not in place; allowed
Massachusetts	Deregulated	Decoupled	CHP has own AEPS standard, utility targets	Yes		Yes
New Jersey	Deregulated	No	Only biomass and fuel cells, in RPS	Yes	Yes	No
New York	Deregulated	Decoupled	Yes	Yes	Yes	Yes
Ohio	Deregulated	In process	Yes	No		Yes

	Utility Regulation	Active Electric Decoupling	CHP in EERS	CHP in Electric EE Programs	CHP in Natural Gas EE Programs	Shareholder Incentives for EE
Pennsylvania	Deregulated	No	Tier II APS resource	Yes	Some	No
Rhode Island	Deregulated	In process	In EE plans	Yes	Yes	Yes
Texas	Deregulated	No	Yes, smaller systems only	Not explicitly		Yes
Wisconsin	Fully regulated	Yes	Not explicit	Yes		Yes - Wisconsin Power & Light

Table Sources: ACEEE 2013; Lucchina 2013

Note: These states chosen for their higher concentrations of new CHP installations in recent years relative to other states.