The Road Still Not Taken:

How Combined Heat and Power Can Contribute to a Sustainable Energy Future in Massachusetts

by

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ABSTRACT

In order to address rising energy costs and global climate change, Massachusetts has adopted greenhouse gas reduction goals and implemented programs and policies to promote the clean and efficient use of energy. Despite these efforts, however, the rate of development of distributed generation (DG) in the state pales in comparison to that of traditional centralized generation facilitates. DG is the production of electricity at or near the location where it will be used. Instead of relying on power generated at large, centrally located facilities and distributed over long transmission lines, DG customers use small, modular generators to produce the power they use. DG units can generate electricity using wind turbines, solar panels, fuel cells, gas powered microturbines or other combustion engines. One class of DG, combined heat and power (CHP), has the immediate potential to accelerate DG growth and drastically improve the efficiency of electricity production. But technical and regulatory barriers associated with interconnection to the electricity grid and general project management challenges inhibit the wide-scale development of CHP. This thesis argues that although Massachusetts has worked hard to bring together members of the public and private sectors to address multiple barriers to DG, specific technical, regulatory, and logistical barriers continue to hinder the ability of Massachusetts energy customers to realize the potential economic and environmental benefits of DG, and CHP specifically. Case studies of CHP projects in Massachusetts are used to illustrate the variety of barriers facing potential CHP customers in the state and how public policy interventions can address those barriers.

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INTRODUCTION

In October of 1976 Amory Lovins published an eye-opening essay in *Foreign Affairs* titled "Energy Strategy: The Road Not Taken?" In the article, Lovins described two divergent scenarios for American energy policy--a hard path and a soft path. The hard path involved continuing to rely on large-scale, centralized electricity generation from dirty fossil fuels and hazardous nuclear power. By contrast, the soft path promised to move us toward greater energy efficiency and energy independence by employing decentralized, distributed electricity generators. Distributed generation (DG) is the production of electricity at or near the location where it will be used. Instead of relying on power generated at large, remote facilities and distributed over long transmission lines, DG customers use small, modular generators to produce the power they use. DG units can generate electricity using wind turbines, solar panels, fuel cells, gas-powered microturbines, or other types of combustion engines. DG is a potential win-win for electricity consumers and society. By investing in DG, consumers can save substantially on their energy costs due to increased fuel efficiency and decreased distribution costs. DG systems also have the potential to decrease prices for other grid customers by limiting the need for transmission and distribution infrastructure expansion and reducing wholesale energy prices. Perhaps most important, the thermal efficiency of combined heat and power (CHP) and the potential for other renewable forms of DG can substantially reduce greenhouse gas emissions and contribute to climate change mitigation.

Thirty years have passed since Lovins published his well-articulated alternative energy strategy, yet as a nation we have only minimally adopted the technologies and practices that Lovins--and a whole generation of environmental advocates--have campaigned for. Despite great advancements in the design of compact solar, wind, and microturbine technologies, we have not had much success at convincing consumers to wean themselves of utility-provided electricity. Despite mounting evidence that many electricity consumers could save money while reducing their ecological footprint by creating their own electricity, a large majority of individuals and firms continue to choose power that is generated at centrally located facilities and expensively transported over miles of transmission wires. Not that all remote electricity generation and long range distribution is inefficient or detrimental to the environment *per se*. Combined cycle gas turbines can now achieve fuel efficiencies of up to 60 percent, and large-scale wind and solar energy projects are generating renewable, emissions-free power all over the country. But DG presents the opportunity to harness positive aspects of either renewable or fossil-based generation technologies in a way that empowers consumers to more directly control their energy flows. In his article, Lovins describes the favorable alternative energy strategy as ideally being based on meeting consumer power needs with renewable, locally-based methods and technologies. But even he concedes that distributed fossil generators could more efficiently meet our energy needs while paving the way for more sustainable modes of DG to follow.

Some argue that the technology exists today to meet all future electricity demand growth from now until 2020 with DG, and that doing so would save consumers over $300 billion and reduce carbon dioxide emission by 380 million tons (Casten and Downes 2004). Yet given current trends in DG development, the Energy Information Administration predicts that only 5 percent of total US electricity demand will be met using DG by 2020 (EIA 2007). By contrast, DG already constitutes 50 percent of electricity generation in Denmark (Casten and Munson 2007). There is considerable potential for DG development in the U.S. , but a coordinated public-private effort is needed to accelerate DG growth in a way that equitably distributes costs and benefits.

Navigating Lovins' soft path will require a paradigm shift in consumer participation in the energy sector as well as advancements in technology and modifications to the market structure of the electricity sector. This thesis examines the benefits of DG, looking closely at one specific type of DG, and addresses the question: What can be done to promote clean, safe and reliable alternatives to remote generation and long-range distribution? Rather than try to generalize about the state of DG policy nationally, I chose to focus my research on a single state, since electricity and most aspects of energy production are regulated at the state level. Furthermore, the thesis will focus on one class of DG, Combined Heat and Power (CHP), because it has the potential to significantly impact the generation mix in Massachusetts in the near term, and pave the way for even cleaner generation technologies in the future. The thesis therefore explores specific aspects of CHP that should be resolved so that CHP can be a transition technology that prepares customers, regulators and utilities for a more flexible energy economy.

I argue that although Massachusetts has worked hard to bring together members of the public and private sectors to address multiple barriers to DG, specific technical, regulatory and logistical barriers continue to hinder the ability of Massachusetts energy customers to realize the potential economic and environmental benefits of DG, and CHP specifically. Using data collected on the characteristics of recent DG interconnection applications and information obtained through interviews, I will show that developers of CHP systems that could potentially provide individual and system benefits to the electricity sector and the environment face a variety of barriers that limit the ability of the state to move toward a sustainable energy economy.

To show how this is true, I begin by describing why we should be focusing our attention on DG, and CHP in particular. I then outline some general barriers to technology adoption to show why DG, and CHP in particular, has had a difficult time penetrating the electricity market. In addition to general barriers to adoption, I examine particular barriers to CHP adoption, the most serious of which are interconnection and project management challenges. I also explore some of the ways that the state has attempted to address these barriers and assess how these efforts might affect future CHP development. Next, I use examples collected from CHP customers in Massachusetts to illustrate the range of barriers that customers face when they attempt to invest in CHP. Finally, I recommend ways that the state could address the various barriers to CHP development identified, citing examples of other state's actions as well as proposing more novel approaches.

WHY DG?

DG is not a new concept. Many DG technologies are proven, certifiable and observable; others -- such as fuel cells and micro wind -- are steadily gaining in reliability and acceptance. But in some ways DG is still a radical idea. DG requires electricity customers to move away from the simple yet costly practice of relying on electric utilities for all of their power needs. Instead, they must shoulder considerable up-front investment, risk, and sometimes operational responsibility to provide the same electricity that they could otherwise obtain by plugging into the existing grid. So why is DG even worth the trouble?

For starters, the conventional electricity delivery approach is expensive and relatively inefficient compared to DG. Long-range transmission and distribution typically loses 9 percent of the electricity it carries before it reaches customers (Casten and Munson 2005). Using DG to meet electricity demand at or near the source of production virtually eliminates line losses. Furthermore, under the status quo, as customer demand increases, distribution utilities build more and more wires and purchase more and more power to meet those needs. If instead, all localized load growth were met with DG, then power producers would not have to expand their capacity and distribution utilities would not have expand their infrastructure (Rawson 2004). One study estimated that DG could reduce the need for T&D infrastructure investment by 90 percent if used to meet all electricity demand growth (Casten and Downes 2004). By reducing line losses and costly infrastructure investments, DG can save all customers money off of their electricity bills.

Another way that DG can produce benefits for all electricity customers is by decreasing the quantity of power produced for the wholesale market, thereby lowering the retail price of electricity. In New England, the wholesale electricity market is run by the Independent System Operator (ISO-NE) who dispatches generation capacity through a variety of markets. One such market, the hourly market, collects bids from eligible generation facilities, then awards the lowest bidders the assignment of producing enough energy to meet hourly customer demand. The highest of the generation bids accepted sets the price that all participating facilities receives. When demand is high, generation facilities with higher operating costs are awarded bids in order to meet hourly demand; and when demand is low, only those facilities with the lowest operating costs are needed to meet customer demand. Therefore, using DG to offset hourly grid demand will make the last facility brought online set a lower price than if demand was greater. One recent study quantified the potential for this demand-reduction price effect to influence retail rates in Massachusetts and found that if 750 MW of CHP DG were operating in Massachusetts in 2020--roughly double the current DG capacity--, it would decrease average annual wholesale energy prices by 3.5 percent, saving grid customers $237 million in that year alone (Drunsic, White and Hornby 2008). Similarly, the same study found that 250 MW of distributed solar PV would reduce prices enough to save energy consumers in the state an additional $23 million.

Widespread DG deployment has the potential to create the system benefits described above. Additionally, many DG technologies can save DG customers significant energy costs by offsetting the cost of purchasing power from the grid. Renewable forms of DG have very low operating costs, since they require no fuel. However the high capital costs and relatively limited generation capacity of renewable DG make for a long payback schedule that is unattractive to many investors. For example, the costs and generation capacity of solar DG technologies currently on the market produce electricity that is two to five times more expensive than the average residential grid price (Solarbuzz 2008). But rising energy prices and falling capital costs are making renewable DG more competitive with power from the grid. Over the past 10 years, average retail electricity prices have risen by 28 percent nationally (EIA 2007). In Massachusetts, the situation is especially acute. Between 2000 and 2006, retail electricity prices have increased by over 60 percent (EIA 2006). In the future, experts predict that technological advances and rising grid prices can make solar DG price-competitive with grid power by 2020 (Hoffman 2005). But until solar DG becomes more price competitive with grid power, there is another, more immediately viable, form of DG that can save energy customers money.

Combined Heat and Power (CHP) is a form of DG that burns fuel to generate electricity and harnesses waste heat and steam to heat buildings, heat water, or even cool buildings. Traditional, remote generation and distribution typically delivers 33 percent of the fossil energy it burns as useful work to consumers, whereas CHP systems can achieve overall system efficiencies of up to 80 percent (Patibandla 2006). This is mainly because the typical means of generating electricity--called the rankine cycle[1]--loses 58 percent of potential energy through heat losses (Casten and Munson 2005), and even state-of-the-art combined-cycle gas turbines waste 40 percent of heat created (GE 2008). CHP systems, on the other hand, are located close to energy customers that can capture waste heat to offset the need to burn additional fuel in boilers, furnaces and hot water heaters to meet their thermal needs. The immediate availability of CHP technologies and CHP's efficient use of fuel make it the most cost-effective form of DG (CEC 2005). One study found that by 2020, if Massachusetts energy customers were operating 750 MW of CHP, they could collectively save themselves $694 million a year by offsetting electricity and heating fuel purchases (Drunsic, White and Hornby 2008).

Saving energy consumers money off their utility bills is certainly a top selling point of DG. But reducing energy use also helps mitigate the threat of global climate change. The scientific community has reached an overwhelming consensus that our prolific and inefficient use of fossil fuels has unleashed enough carbon dioxide and other greenhouse gasses to fundamentally alter the composition of the atmosphere, trapping heat and raising global surface temperatures. Studies show that this greenhouse effect is causing the earth's temperature to rise at an alarming rate (IPCC 2007). The warming climate is changing weather patterns, resulting in more severe storms, persistent drought, ecosystem change, and rising lea levels. Experts agree that unabated, climate

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[1] The rankine cycle is a method of electricity production where fuel is burned to heat water and create steam. That steam is then used to turn a turbine and generate electricity.

change will inundate coastal communities, disrupt water supply systems and threaten global food production (Pew Center 2007).

But there is hope. The Intergovernmental Panel on Climate Change contends that climate stabilization can be achieved using available or emerging technologies to reduce greenhouse gas emissions (IPCC 2007). In order to do this, the panel recommends that appropriate incentives be implemented to encourage a portfolio of cleaner and more efficient technologies and practices. Since 33 percent of greenhouse gas emissions in the U.S. stem from electricity use (EIA 2006), addressing electricity consumption should be high on our list of priorities for mitigating climate change. Various scenarios have been proposed to reduce greenhouse gas emissions from electricity generation (see Pacala and Socolow 2004; Gore 2006), and all of them include using fossil fuels more efficiently and employing significant renewable energy generation capacity. DG can contribute to both these goals. In the long term, distributed renewable technologies are an ideal way to help meet our energy needs and mitigate climate change. But in the near term, we need to do everything we can to reduce greenhouse gas emissions by using fossil fuels more efficiently. Even though CHP systems burn fuel and produce greenhouse gases, the fuel efficiency of CHP compared to traditional generation can contribute to significant net reductions in greenhouse gas emissions. One study comparing two scenarios of meeting future load growth in the US between now and 2020 with either 100 percent centralized generation or 100 percent CHP illustrates the magnitude of the potential environmental savings. If CHP were used to meet this incremental demand, carbon dioxide emissions growth could be reduced by 381 million tones, or about 6 percent of annual greenhouse gas emissions (Casten and Downes 2004).

DG must be a part of our national strategy to offset greenhouse gas emissions to avoid global climate change. CHP is the type of DG most immediately capable of significantly affecting the power generation mix, and the overall fuel efficiency of CHP can save energy consumers money.

WHAT'S THE HOLD-UP?

Reducing national greenhouse gas emissions by 6 percent as described in the previous section would go a long way toward mitigating climate change, but meeting all incremental demand with CHP is not necessarily an immediately achievable goal. For one thing, since CHP requires customers to break away from utility-provided service in order to purchase, install and operate a set of technologies that they often have no experience with, CHP adoption faces several barriers that are common to the diffusion of any innovative product or service. Furthermore, if energy customers decide to invest in CHP, they still face two general types of barriers. One set of barriers involves establishing a physical connection and business agreement with the electric utility to operate a CHP system. The other set of barriers includes project management barriers, such as technological and logistical challenges. Massachusetts has taken steps to address some of these barriers, including standardizing the interconnection tariff and creating incentives to promote DG, but there is still work to be done.

General Barriers to Technology Adoption

In general, before an individual or firm decides to change a practice or adopt a new technology, they require some level of certainty that their cost and risk will be worth the potential benefits of adoption. There are five factors that affect whether or not a potential adopter decides to pursue an innovative technology or practice: *relative advantage*, *compatibility*, *complexity*, *trialability*, and *observeability* (Rogers 2003). Of those five factors, *relative advantage*, *compatibility*, and *complexity* are most relevant to the decision to invest in CHP.

Relative advantage describes how the adopter perceives the benefit of the new technology over the one that it supplants. How much better off is the user when they invest in CHP versus if they would have continued to buy all of their power from a utility? Are the benefits obvious to potential adopters? From the perspective of potential investors, the benefits of CHP over traditional centralized generation and distribution are most easily measured in dollars. But the regulatory and market structure of the electric industry Therefore clear price signals should indicate when a potential adopter should invest in CHP. Since, in addition to customer energy expenditure savings, CHP has the potential to create system-and society-wide benefits, some of those savings should be monetized and shared with the CHP customers who generate them in order.

Compatibility describes how well the new technology fits within the existing values and needs of the adopter. Does producing one's own power seem to conflict with the overall mission of the firm or institution? Installing DG capacity requires the diversion of investment and human capital away from normal business operations. There are often institutional barriers within businesses or institutions that inhibit DG investment, such as lack of familiarity or unwillingness to divert investment capital from other purposes (Cummings 2008).

Complexity describes how well the potential user understands the new technology and can operate it. Potential CHP investors may be deterred from investing in it because they are intimidated by the interconnection process and project management challenges that accompany CHP implementation as described in the following sections.

Interconnection Barriers

Interconnection refers to both the physical connection between a DG system and the electric distribution grid as well as the business relationship between a DG customer and the utility that owns and manages that grid. All types of DG must interconnect with the grid if the customer wants supplemental or back-up power, therefore addressing interconnection barriers will aid not only CHP development, DG development generally. Because of the complexity of power generation and distribution, there are a variety of technical barriers to DG interconnection. Connecting to the electricity grid requires specific equipment both on the customer's side of the meter and on the utility's side of the meter. Since the utility is ultimately responsible for the safety and reliability of the grid, the utility requires very specific technologies such as protective switches, voltage protectors, and distribution wire upgrades.

While no one denies that safety and reliability are legitimate utility concerns, some believe that utilities often require unnecessary equipment in order to drive up DG project costs and discourage DG investment. As regulated monopolies, electric utilities are told how much they can charge per unit of power based on their estimated total cost and estimated total demand. While prices are controlled, they still allow the utility to earn a profit on each unit of energy it sells. This revenue scheme gives the utility the incentive to maximize its profit by selling as much power as it can. This throughput incentive for energy sales sets up a conflict when DG customers seek to negotiate the terms of their interconnection because the utility may want to deter DG installments that have the potential to significantly diminish profits. For example, utilities may require unnecessary line upgrades, overly-redundant safety equipment, or costly technical feasibility studies. Each of these adds to the cost and complexity of the project. In a nationwide survey of DG customers published by the National Renewable Energy Laboratory, 49 percent of the 65 customers interviewed reported that their project had been delayed or made more costly by technical barriers imposed by the utility, and many felt that these technical requirements were excessive (Alderfer 2000).

But Joseph Faraci, senior engineer in charge of interconnection applications at NSTAR, argues that the requirements imposed by utilities are vital to the reliability of the grid and the safety of utility personnel. In a telephone interview, Mr. Feraci described a dangerous condition, called "islanding", in which a portion of the grid looses power from the utility but continues to receive power from distributed generator(s). When maintenance crews go out to work on the line in question, they risk coming into contact with live wires that they believe to be de-energized. In order to protect against this, NSTAR requires all DG customers seeking interconnection to install an external disconnect switch, so that utility crews can manually disconnect the DG unit from the grid if they need to work on the line (Feraci 2008).

The external disconnect switch required by NSTAR only adds a few hundred dollars to the price of installation. But other interconnection equipment specifications or grid upgrades can impose such high costs that potential DG developers are forced to abandon their project. One such factor that can significantly increase the cost of interconnection is if the DG customer is located on a secondary distribution network. Most of the electricity grid is served by radial, or primary, distribution lines that carry power from transmission lines to individual customers. However in order to achieve reliability in dense urban areas, networks of interconnected primary lines provide redundancy to prevent large-scale power loss in the event of a single line loss. These secondary network distribution systems can carry power between primary lines, but not between the secondary network and the radial distribution system. In order to prevent reverse power flow between a secondary network and the radial feeders, a type of circuit breaker, called a network protector, is used. If the network protector senses reverse power, it opens and power is cut off from that one primary line of the secondary network, but since the network is fed by several primary lines, the customers do not experience any difference in service (CEC 2003). Under normal circumstances, reverse flow is rarely a problem, but when a DG system is connected to a secondary network it increases the likelihood that a network protector would be triggered, causing wear and tear on a vital and expensive piece of equipment. In order to prevent this from happening, distribution utilities either ban DG on secondary networks, limit DG capacity to a very low quantity of power, or require the DG customer to install a dedicated radial line (which can handle reverse flow) to serve their standby power needs (Feraci 2008).

Although technically feasible in many cases, installing a dedicated radial feeder can be prohibitively expensive. Before going through the effort to fill out an interconnection application, potential DG customers often ask whether they are located on a secondary network. If customers learn that they are served by a secondary network, they almost always discontinue their inquiry (Feraci 2008). A major benefit of DG is that it can offset transmission and distribution upgrades to meet load growth. But if DG cannot be connected to secondary distribution networks, its effectiveness at meeting load growth in urban areas will be diminished. Furthermore, excluding DG from urban areas where secondary networks are prevalent would preclude large commercial and residential buildings with a substantial enough thermal load to warrant a cogeneration system from investing in CHP. The technical complications of connecting DG to secondary distribution systems therefore present a major obstacle to maximizing the potential effectiveness of CHP.

Standby charges are another controversial issue related to interconnection that can impede DG development generally. CHP units have to be shut down periodically for planned maintenance, and they occasionally have power failures. Customers may even choose to shut down their generators to buy power from the utility when it costs less than producing their own power. In order to provide these supplemental and backup power services, utilities require customers to pay standby charges to cover the cost of the maintaining generation and distribution infrastructure to serve the intermittent needs of the DG customer. Determining these standby charges is often a contentious process, and many customers believe that utilities artificially inflate the cost of providing standby service to discourage them from installing DG. A 2000 report by the National Renewable Energy Laboratory cited excessive standby tariffs as the single greatest regulatory barrier to DG (Alderfer 2000).

CHP Project Development Barriers

Apart from the barriers to DG development associated with interconnection, CHP developers also face numerous technical and logistical project management challenges inherent to this particular class of DG. For example, the single major factor that limits the potential for widespread CHP development is inadequate or uneven thermal demand. Since CHP makes its efficiency gains by harnessing both heat and power, a low demand for heat makes it uneconomical to generate electricity. CHP projects are therefore limited in size by the existing thermal load. This is the main reason why CHP has historically been mostly used in industrial facilities such as petroleum refineries and paper mills (Neal and Spurr 1999).

Another limiting factor to increased CHP development is air quality permitting. Although CHP has the potential to burn less fuel than conventional systems to create the same amount of electricity and heat, this does not necessarily translate into direct air quality benefits. CHP systems still emit pollutants, and since CHP units are not remotely located, those emissions more directly affect human health. In order to address this issue, state and federal regulators strictly monitor CHP emissions. Current environmental permitting practices are applied based on allowable quantities of pollutant output per unit of fuel input. Such pollution accounting only accounts for the type of fuel used, not for how efficiently that fuel is used, and thereby does not properly account for the net environmental benefits of CHP. (Bluestein, Horgan and Eldridge 2002). This sets up a conflict between competing environmental goals. On the one hand, CHP can reduce net pollution by using less fuel to provide both heat and power. But at the same time, the emissions created by that CHP must not jeopardize the health and well-being of those nearby. Consequently, air quality compliance costs are often high for CHP. An example of this barrier is explained in more detail in the MIT case study found in the next section.

Another potential CHP project management challenge is securing an adequate and reliable fuel supply. Roger Moore, who oversaw the design and implementation of a large cogeneration facility at MIT, cited fuel reliability as one of the major obstacles that hindered that project's development. Natural gas is often the fuel of choice for CHP facilities because it burns cleanly and is distributed via an existing infrastructure that is usually easy to access (Bautista 2001). As a case study described in the next section shows, however, the existing gas supply cannot always meet the needs of a large cogeneration plant. Fortunately, the project was large enough to warrant spending the time and money to secure a reliable fuel source. Smaller customers and those using alternative fuels have more difficulty overcoming these obstacles to economic fuel availability. For example, Iggy's Bread of the World, another case described in the next section, will use biodiesel to fuel a 45 kW cogenerator and is facing escalating fuel prices that may ultimately jeopardize the cost-effectiveness of the project.

Barriers related to project development show that apart from interconnection, which can usually be addressed through engineering or regulatory interventions applied on a wide scale, there are many other practical considerations that require project-specific solutions. This speaks to the *complexity* of distributed generation, a factor that has been shown to deter people from adopting innovative technologies or practices.

DG in Massachusetts

The state of Massachusetts has recognized that climate change is a serious global as well as local threat. The state has taken several large steps to curb greenhouse gas emissions including signing on to regional greenhouse gas reduction treaties and aggressively promoting renewable energy installation and manufacturing. In 2001, Massachusetts became one of 11 signatories on the New England Governors and Eastern Canadian Premiers Climate Change Action Plan to voluntarily pledge to reduce greenhouse gas emissions to 1990 levels by 2010 and 10 percent below 1990 levels by 2020 (Stoddard and Murrow 2006). Later, in 2007 Governor Deval Patrick signed the state onto the Regional Greenhouse Gas Initiative, which will institute a cap-and-trade system on greenhouse gas emissions from the electricity generation sector with the aim of reducing greenhouse gas emissions by 10 percent below 2009 levels by 2018

(RGGI 2007). Also in 2007, Governor Patrick announced a goal of increasing solar DG in the state from 2 MW of capacity presently to 250 MW by 2018. These actions prove that Massachusetts is committed to taking action to address climate change by instituting programs and policies to reduce greenhouse gas emissions from the energy sector.

Furthermore, in 2002 the Massachusetts Department of Telecommunications and Energy (DTE) created the Massachusetts DG Collaborative to investigate how the state cold further promote DG as part of its sustainable energy agenda. The DG Collaborative is charged with investigating the barriers to DG and its affects on the electrical distribution system. Participants include utilities, equipment manufacturers, energy customers, renewable energy advocates and state agencies, with mediation services provided by Raab Associates, Ltd. (DGIC 2003). After determining that issues associated with DG interconnection to the grid were major barriers to DG development, the Collaborative drafted model interconnection standards and tariffs to ameliorate customer concerns that utilities were making interconnection unnecessarily cumbersome and expensive while ensuring that all DG systems would not jeopardize the safety, quality and reliability of the grid (DTE 2002). The ultimate goal was to make interconnection predictable and transparent to relieve uncertainty and promote DG adoption.

The resulting standards, which were eventually adopted by the DTE as well as each of the four private distribution utilities, create three application processes based on the potential grid effects of a proposed DG project (DGIC

2003). For example, a DG unit producing 10 kW
or less of power and located on a radial distribution network could complete the Simplified application process, which has a low threshold for proving the DG system's compatibility with the grid. Larger DG units and those located on secondary distribution networks receive a higher degree of scrutiny and therefore must complete either the Expedited or Standard application process, which are much more costly and time consuming than the Simplified process.

After the interconnection standards were adopted by the DTE in 2004, the MTC collected data on interconnection applications in the state for the next two years to monitor the DG adoption rate. Although no data is available on interconnection application characteristics before the uniform standards were adopted, the MTC's data for this two-year window show some interesting trends that suggest how DG development may evolve. For example, in the two years that the study covers, only one customer located on a secondary network completed an application for interconnection to the state's distribution utilities. This single potential DG customer located in a secondary network subsequently withdrew its application, for reasons not specified in the report (DGIC Collaborative 2006). On the other hand, 276 out of the 331 customers located on radial distribution lines that applied for interconnection permits had their applications approved. Of those 276 approved DG interconnection applications, 233 were for solar PV generators and 36 were for natural-gas-fired generators. Although 233 DG solar installations is commendable, their impact on total load share is minimal. The combined total capacity for all 233 solar installations was

.925 MW. By contrast, the 36 natural gas systems combined to bring a potential 13.73 MW of power online (DGIC 2006). These figures show a pattern of small, mostly solar DG development throughout the state, with no installations on secondary networks. Since experts predict that the state's electricity demand will grow by 1 percent, or 113 MW, annually (ISO NE 2008), this pattern of DG development would barely contribute to meeting the needs of the state in a more cost-effective and environmentally sustainable manner.

The MTC has also tried to mitigate the challenge of siting DG on secondary distribution networks. A working group within the collaborative has studied the possibility of using high-speed communications between network protectors and DG units to automatically disconnect a DG unit from the grid when it senses that the network protector could be compromised. In order to test the effectiveness of these network protectors to regulate power quality and prevent reverse power, the working group applied them in a pilot study on the Williams Federal building in downtown Boston. Thus far, the study has been considered successful, since the network protectors have been able to regulate the flow of power from the 75 kW combined heat and power unit to assure the reliability and safety of the grid. The design is still at the beta stage, however, and requires modifications and testing before conclusions can be made about the greater potential for DG on secondary networks.

Overall, the Collaborative has accomplished the tasks that were assigned to it by the DTE. But it is too early to evaluate the ultimate impact that their work will have on the proliferation of DG. One pessimistic DG developer I interviewed said that ratepayers needs were not being fully addressed by the work of the Collaborative because they were not represented at the numerous meetings and within the different working groups. He indicated that it is difficult for DG customers to pay to have someone attend these meeting, while the utilities can afford to provide adequate staff to ensure that their needs are heard. Consequently, some believe that utility interests were reflected more strongly than consumer interests in the tariff and other Collaborative efforts.

In order to address DG customer concerns about exit fees and standby charges, in 2007 the DTE launched a stakeholder process, similar to the DG Collaborative, to investigate ways to quantify the real cost of DG that the utilities bear in order to design a more equitable tariff structure (DTE 2007). While only in its nascent stage, this effort has the potential to bring down DG development costs and increase DG participation. Furthermore, in June of 2007 the DTE opened a separate inquiry into rate structures that would better accommodate demand resource efforts such as energy efficiency, load shedding, and DG (DPU 2007). This effort will investigate ways to decouple utility profits from energy sales, so that utilities within the state will no longer face perverse incentives to impede efforts to curtail energy use or develop alternative sources of power.

Though technically not a state level action, ISO New England's new Forward Capacity Market (FCM) is an important development in alternative energy policy. ISO New England is the regional transmission organization responsible for managing wholesale electricity sales and ensuring that adequate and reliable generation capacity is available to meet the needs of the region.

The FCM is a mechanism for certifying and rewarding supply-side resources such as new and existing generation as well as demand-side resources such as energy efficiency, load management and DG in order to guarantee that these resources will be available to meet New England's power supply needs (ISO NE 2008). The FCM essentially rewards energy resources if they can guarantee that they will produce or eliminate the need for a MW of power. This creates a potential revenue stream for demand side resource such as DG that can provide system reliability by eliminating some customer demand. As an example of the scale of this capacity incentive, a 2 MW CHP facility operating year-round would earn over $100,000 in capacity payments at the lowest auction price, $4.5/kW-month. Several of the DG customers I spoke with said that the FCM is an attractive incentive, but in the first Forward Capacity Auction the majority of capacity was awarded to load management and energy efficiency, with only 4 percent going to DG (Ethier 2008). It is unclear exactly why DG represented a small percentage of demand response capacity, but it could be an indication that the transaction costs of getting certified and participating in the Forward Capacity Auction are a deterrent to DG customers. Or it could be that there are other characteristics of load management and energy efficiency that make them more competitive on the FCM.

In sum, Massachusetts has taken steps to make its energy supply more sustainable, including attempting to address specific barriers to DG. Opening a dialogue between regulators, DG advocates and utilities was a big step toward designing policies to foster DG, and the resultant standardized interconnection tariff makes DG installation consistent across utility service territories. But recent data suggests that DG installations are still not proliferating at a rate that will significantly alter the state's generation mix. As the following case studies show, major barriers to DG, and CHP in particular, are still present and have not been fully addressed by state efforts.

CHP PROJECTS IN MASSACHUSETTS

In order to get a better picture of the barriers to CHP development in Massachusetts, I interviewed developers of four CHP projects. I chose these projects because they demonstrate the variety of available CHP generation technologies and their stories highlight common interconnection, environmental permitting and project management challenges. I asked them to walk me through the project development process from the initial decision to pursue DG through to installation, interconnection and operation. While there was no common barrier that impeded them all, each of the project managers reported that the overall complexity of CHP projects makes them difficult to carry out. In particular, two of the four developers interviewed reported facing obstacles negotiating interconnection with the utility, and others described a variety of project management challenges, including problems with procuring fuel, meeting environmental standards and matching thermal load with electricity demand. These barriers increased the *complexity* of the CHP projects, and cased cost increases that threatened the *relative advantage* of the projects.

MIT Cogeneration

The following case illustrates how fuel supply issues, air quality regulations and interconnection charges add significant complexity and cost to a large CHP project. The Massachusetts Institute of Technology owns and operates a 20 MW natural gas-fired combustion turbine equipped with a heat-recovery steam generator. The plant opened in 1994, and was designed to generate enough electricity to supply the campus with most of its load while simultaneously providing enough steam to heat and cool the campus throughout the year. This CHP facility supplies the campus with 60 percent of it electricity needs, 80 percent of its heating needs, and 60 percent of its cooling needs. Roger Moore, the institute's Superintendent of Facilities described the numerous regulatory and project development obstacles that had to be overcome during the eight years that it took to design and permit the project.

From the beginning, the Institute's administration required the CHP project to have a long-term fuel supply contract to minimize the risk of fuel shortage or price increases. Before they would approve a project to make the Institute nearly energy independent, the administration wanted assurances that the plant would be highly reliable. Initial engineering studies showed that the thermal demand of the campus warranted a 20 MW CHP system, but procuring enough natural gas to fuel such a system was a potential limiting factor. Ensuring a fuel supply contract was initially problematic because the existing natural gas utility that supplied most of the residential and commercial gas customers in the area, Commonwealth Gas, could not accommodate such a large growth in demand. When the existing natural gas delivery infrastructure in Cambridge was not sufficient to serve the needs of the new plant, the project development team hired a consultant to search for a new source of fuel. The consultant investigated several gas delivery options, including importing liquefied natural gas (LNG). But none of the options guaranteed the high level of supply stability that the

Institute's administration required. A few natural gas distributors from nearby areas and states were considered, but none could supply the large quantity of fuel that the CHP plant would need. LNG, which could be delivered onsite in large enough quantities, mostly originates in Algeria, where political unrest made the Institute wary of the long-term stability of the supply. Eventually, the issue was resolved when a large industrial facility in another area of Cambridge closed down, freeing up enough existing local supply to meet the Institutes needs. In order to access this increased gas capacity, however, MIT had to build a one-mile gas pipeline at a cost of $1 million.

By June of 1989 MIT, had completed its CHP plant design and was prepared to initiate the environmental permitting process. The project development team encountered a major barrier when their air permit application was denied by the Massachusetts Department of Environmental Protection (DEP) for exceeding the maximum limit for nitrogen oxide (NOx) emissions. At that time, the best-available control technology, which MIT was required to implement under the federal Clean Air Act, used ammonia gas to reduce NOx emissions to 9 ppm. MIT was not comfortable storing large quantities of ammonia on site, however, so it proposed an emerging low-NOx combustion technology that would emit 15 ppm NOx but require no ammonia scrubbers. DEP was not comfortable approving this. It was not until Dr. Janus Beer, director of the MIT experimental combustion lab, became involved in the project that MIT could demonstrate that, based on trials in Sweden and Switzerland, .NOx emissions would be slightly elevated but the absence of ammonia from flu emissions would result in a net improvement in air quality. MIT eventually secured the necessary permits.

The third major obstacle that the MIT CHP development team encountered was negotiating an exit fee and standby charges with the electric utility Cambridge Electric Company (CELCO). In order to provide supplemental and backup power CELCO imposed a $7.8 million exit fee on MIT to cover what the utility claimed were stranded costs, or previous generation investments made by the utility to fulfill the anticipated demand of MIT. Since MIT was no longer a regular customer, CELCO claimed, the utility could not pay off the investments it had made on MIT's behalf. The Institute felt that this exit fee was extraneous, so it brought a formal complaint before the DTE to have the matter adjudicated. But the DTE ruled in favor of CELCO, citing the need to fund capacity as justification for such exit fees. MIT was still not satisfied, so it appealed its case to the Supreme Judicial Court of Massachusetts, where it eventually was relieved of all but $1.3 million of the exit fee.

In addition to the exit fee, CELCO required high standby charges to provide supplemental and emergency power to the Institute. In order for the utility to maintain enough generation and distribution capacity to meet MIT's needs in the event of an unscheduled plant closing, the utility would impose a $10/kw, or $200,000 charge every time the plant unexpectedly went offline. Even though the project management team felt that this standby charge was unnecessarily high, and that it had perhaps not even been determined by the actual cost of providing standby service, they did not feel that it was worth it to engage in another lengthy battle to fight the charge, so they accepted it and it still stands today.

Even after a host of delays and unexpected costs, the MIT administration decided to move forward with the project. This was primarily because the Institute calculated that the CHP plant would be profitable, with a return on investment of 18 percent and a simple payback of five years. The Institute was able to earn such substantial cost savings because it could simultaneously fulfill its steam and power needs, --and do so more cheaply and reliably than if it had continued to receive utility service. According to Mr. Moore, Cambridge experiences a major power outage four to five times a year, while MIT's CHP plant has gone up to seven years at a time without failing unexpectedly. Furthermore, because of the energy efficiency and clean technology employed by the plant, MIT has reduced the amount of criteria pollutants (carbon monoxide, nitrogen oxide, sulfur dioxide, ozone, lead, and particulate matter) associated with its electricity production by 40 percent and its overall carbon dioxide emissions by 32 percent.

Implementing the CHP plant at MIT took strong leadership, substantial up-front investment, and eight years of negotiating with regulators and energy utilities. Luckily, MIT had the capital, expertise, and drive to complete the project. The cogeneration plant has been such a good investment for MIT, that it is currently investigating the possibility of expanding their plant by an additional 15 MW of capacity to meet the growing heat and power needs of the Institute.

Harvard's Blackstone Plant

Another example of a capital-intensive, complex project is Harvard University's Blackstone power plant. In 2002 Harvard purchased the Blackstone Steam Plant from the electric utility NSTAR. The plant, originally built by the Cambridge Electric Company in 1901, had been used to generate electricity for Cambridge customers as well as steam for Harvard University. At the time that Harvard purchased the plant it was no longer generating electricity, but it was providing 80 percent of the University's buildings with heat from four antiquated boilers fueled by heating oil . Doug Schmidt, Blackstone Project Manager, was hired by Harvard's Engineering and Utilities Department in 2004 to oversee the implementation of a CHP facility at the Blackstone Plant. Mr. Schmidt described the motivation for the project and outlined the various barriers and benefits that the project has experienced thus far.

Harvard originally purchased the plant because it was dependent on the steam the plant produced to heat most of the buildings on the university's Cambridge and Allston campuses. At that time the plant and its ancillary buildings were suffering from 40 years of neglect and would require $40 million in building retrofits and equipment upgrades. Even though reliable and cost-effective steam production was the main driver for the project, the Harvard administration also saw this as an opportunity to fulfill the university's commitment to environmental sustainability. Therefore, the project was designed to include the replacement of two of the four fuel oil boilers with state-of-the-art natural gas boilers. Additionally as a means of regulating steam pressure from these boilers, Harvard elected to purchase a 5 MW microturbine to convert some of the mechanical energy of the steam into useful electricity.

Once it is operational, the turbine will use approximately two-thirds of the steam produced by the plant to generate enough electricity to provide the university with 11 percent of its peak demand. The decision to limit the capacity of the generator was based on a simple payback analysis that weighed the cost of the generator against the cost of electricity that the generator would offset and how often it would be in service. Since the primary purpose of the boilers is to make steam to heat Harvard's buildings, the plant dose not produce enough steam in the summer months to generate electricity with the microturbine. Even with an abbreviated operating season, the $2.5 million turbine is expected to pay itself off in 2.5 years based on the avoided cost of the 5 MW of electricity it will produce.

Unlike MIT, Harvard did not have much of a problem securing environmental permits because its state-of-the-art gas boilers are very clean, especially compared with the antiquated oil boilers they are replacing. Mr. Schmidt expects the Blackstone steam turbine to be operational by Summer 2008, although it will not go into full use until colder weather necessitates sufficient steam to power the turbine.

In short, the only barriers described by Mr. Schmidt were project management challenges related to thermal load and the age of the existing plant. However this case illustrates that even if permitting goes smoothly, DG projects can be extremely costly. Like MIT, Harvard's DG investment required leadership, substantial capital, and the desire to take on a complicated project to achieve social benefits. Millions of dollars were spent to retrofit the facility and its infrastructure to accommodate the cogeneration system. Realizing this project took four years of design, project analysis and construction. Harvard may have the available capital and initiative to make such this project work, but other smaller firms may not be able to handle such project management challenges. Furthermore, since Harvard's boilers operate only during cold-weather months, there is a limited window of time for its turbine to generate electricity and pay itself off.

Acushnet Company

This next case was chosen because it illustrates weaknesses in the current interconnection tariff structure. Before a firm can have an accurate picture of what their interconnection costs will be, they have to invest time and money to submit a thorough application and wait for the utility to make a grid-impacts determination. This makes it expensive to even investigate whether CHP could make financial sense for a firm.

Acushnet Company operates a golf ball manufacturing facility in New Bedford, Massachusetts. Acushnet sought a CHP system to more efficiently meet its hot water, steam and electricity needs. Acushnet's objective was to reduce operating costs by matching the plant's thermal load with the output of a CHP system. The final decision to invest in DG was made by the company's Capital Committee based on a life-cycle payback analysis. A 2 MW natural gas-fired reciprocating engine with exhaust gas and jacket cooling heat transfer equipment was ultimately selected to match the thermal load of the plant with its electricity demand. This CHP system now supplies the plant with 45 percent of its electricity demand and 65 percent of its heat and hot water needs.

Bob Espindola, Energy Systems Project Manager at Acushnet, reported that that the major barrier to developing this project was negotiating the grid interconnection with NSTAR. Mr. Espindola explained that it took 6 months for NSTAR to investigate and report the findings of a grid impacts study that said that Acushnet would be responsible for installing an air core reactor to mitigate the ground fault current potential of the generator. The purchase and installation of this air core reactor added an additional $140,000 onto the cost of the $2.8 million project. At that point in the project development stage Acushnet had already invested considerable time and capital in their CHP project and they were committed to seeing it through.

Mr. Espindola suggested that a more streamlined and unbiased approached to interconnection would use an independent third party to conduct the grid impact study. He speculated that since the current grid impact evaluation is performed by the utility and there is no mandate for transparency, there is an opportunity for the utility to protect their throughput interests by stalling DG projects and adding to project costs. He further suggested that it would be helpful if DG project proponents had a clear idea of what grid upgrades they would be required to complete and what standby charges they would be responsible for at an earlier stage in the project development. It was not until Acushnet had hired outside consultants and NSTAR had completed their grid impact study that Acushnet was informed of its grid upgrade obligation and standby charges.

South Boston Artist Studios

Not all DG projects use proven technologies like those employed by MIT, Harvard and Acushnet. Some DG developers choose to push DG innovation even further to meet their specifics needs or goals. Second Street Associates (SSA) is a developer of green residential buildings in Boston. Mark Anstey, Chief Engineer and Project Manager for SSA, described their recent efforts to implement a DG project at an artist live-work studio in South Boston. The Distillery, a converted 19^{th} century rum factory, has been used by artists since 1984. SSA recently acquired the property and is in the process of implementing several green features including a groundwater cooling system, heliostats that will automatically track the sun with mirrors to direct sunlight into the building, and a CHP system powered by vegetable oil. Mr. Anstey reported no technical or regulatory barriers, only project development challenges related to the innovative fuel source.

In 2006, SSA received a grant from the Massachusetts Technology Council (MTC) to complete a feasibility study for the use of used vegetable oil, or yellow grease, to power a 45 kW diesel generator CHP system. Mr. Anstey described this as a demonstration project to show that yellow grease could be used for DG. To his knowledge, yellow grease has been successfully used as a transportation fuel in a diesel engine, but never as a fuel source for DG. The main driver behind the decision to pursue DG, and this fuel source in particular, was to reduce greenhouse gas emissions. Not only does such a project maximize fuel efficiency by capturing waste heat, but, because the fuel is made from organic material that sequestered carbon during its life-cycle, the net carbon emissions are less than from fossil fuels. Additionally, such renewable energy DG can earn renewable energy credits, which can be sold to increase the profitability of the endeavor.

The one barrier that has forced SSA to place the project on hold temporarily is that the manufacturer of the diesel engine they plan on using will not extend their warrantee to cover this new fuel source. The manufacturer would warrantee for use with biodiesel or pure vegetable oil, but not used vegetable oil. Mr. Anstey indicated that SSA will continue to work with the manufacturer to resolve the issue.

Since SSA's DG project has not been fully implemented, Mr. Anstey could not say for certain whether utility interconnection or standby charges would be a barrier. However since the Distillery is located on a radial distribution network, and the planned DG system is only 45 kW, interconnection may not be too complicated.

Mr. Anstey also mentioned that he is involved in the development of a similar project at Iggy's Bread of the World in Cambridge. Iggy's is a wholesale and retail bakery that is developing a DG project that will use biodiesel to power a 45 kW generator. Mr. Anstey indicated that Iggy's owner Igor Ivanovic is pursuing this project as a part of his sustainable business model. He speculated that the project would likely be operational in the near future. Upon review of the feasibility study for this project completed in 2005, I can see that a potential problem is the cost of biodiesel relative to the cost of electricity. According to the report, based on the range of prices observed for pure biodiesel, the $187,000 project could have a simple payback of between 5 and 35 years (Lyons 2005). This fuel price uncertainty and wide-ranging return on investment would likely be unfavorable to many potential investors, but Mr. Ivanovic's commitment to innovation and sustainability make him tolerant of the risk.

The experience of SSA and Iggy's bakery shows that DG innovators are willing to take risks for the sake of enhanced environmental performance. Even though the relative advantage of the fuel choice is not well understood, these entrepreneurs are willing to develop DG as a way to increase energy efficiency and reduce greenhouse gas emissions. Due to the novelty of the technology and fuel price uncertainty, however, DG from biofuels is not an immediately suitable method for bringing DG up to scale in the state.

Although the limited number of cases presented here cannot hope to illustrate all of the opportunities, limitations and challenges of CHP development, they do paint a picture of the range of CHP project opportunities from large institutions to industrial facilities to artist live-work space. They also illustrate how issues surrounding interconnection and project management challenges continue to make CHP development problematic. The unresolved interconnection issue of standby charges and non-transparent grid impact analysis make CHP developers wary of utilities efforts to thwart their DG projects. If CHP development is going to continue to be as complex and time consuming as illustrated in these cases, then measures should be taken to make CHP more profitable relative to traditional power procurement if the state really wants to promote CHP as a sustainable energy alternative.

THE ROAD AHEAD

The future for DG in Massachusetts is bright. The state has shown that it is committed to expending resources to help energy customers pursue alternative energy resources. The political and economic climate is turning toward DG to contribute to mitigating climate change and decreasing energy costs. The MTC's DG Collaborative, along with the DPU have begun to address some of the most important technical and regulatory barriers to large-scale CHP deployment, but project costs and the complexities of implementation continue to hinder CHP development. In order to facilitate greater adoption of CHP and DG generally, Massachusetts should provide greater incentives and market mechanisms to promote CHP as well as relieve as much of the complexity as possible from CHP investment and implementation.

Provide Incentives to Increase the *Relative Advantage* of CHP

As discussed in this thesis, CHP can be cost-effective for some customers, but project management barriers and interconnection challenges still deter potential adopters from pursuing it because the *relative advantage* of CHP over traditional electricity procurement is either not persuasive, or not obvious. CHP has inherent challenges, but greater incentives could be put in place to attract more customers in order to achieve the system and environmental benefits that widespread CHP could provide. For example, while CHP customers can enjoy the cost savings of their fuel-efficient system, they receive very little of the societal benefits of reduced greenhouse gas emissions and reduced need for generation and transmission expansion. In order to increase the relative advantage of DG, Massachusetts should enact policies that reward DG customers for contributing to system benefits and increased environmental quality. By internalizing the external benefits of DG, Massachusetts could create better incentives to promote DG.

One way Massachusetts could internalize the external benefits of DG is to create an Alternative Portfolio Standard (APS) so that CHP can earn and sell generation credits. Doing so would create a revenue stream for CHP customers by allowing them to earn credits for the electricity they produce that they can then sell on an open market. By requiring utilities to purchase these credits, the state would create a mechanism that captures the external benefits that utilities and ratepayers enjoy and reward DG customers. Pennsylvania and Connecticut already have an APS that rewards CHP as well as energy efficiency and several states– Colorado, Hawaii, Nevada, North Carolina, North Dakota and Washington–include CHP in their Renewable Portfolio Standard (RPS) (EPA 2008). It is not advisable to include CHP in an RPS though, since then CHP would compete directly with renewable energy technologies instead of being promoted along side them.

Net metering is another example of a current state policy that could be amended to further promote CHP over traditional electricity generation. Currently, DG customers with a generation capacity of less than 60 kW can sell surplus electricity that they produce but do not immediately consume to the utility for other customers to purchase. The customers are compensated for the amount of power they provide back to the grid at the average monthly market price. This provides a revenue stream for small DG customers, but does not help medium and large DG customers. But as shown in the above cases, CHP often works best for medium and large sized customers with the thermal load to warrant the investment in CHP and the institutional capacity to complete such a complex project. Massachusetts should remove the 60 kW cap on who can participate in net metering, or at least increase the ceiling to 2 MW like Colorado, Connecticut and New Jersey have done.

Another market mechanism that could increase the profitability of DG is to build a small congestion charge into the retail electricity price and use the revenue from that fee to reward DG developers. New England currently uses a Locational Marginal Pricing (LMP) scheme that determines the retail price of electricity based on the cost of generating and delivering a unit of power to a particular place at a particular time. By factoring in the real cost of generation, transmission and distribution, LMP sends a price signal to consumers in load constrained areas to use less electricity and also makes it more attractive to energy developers to provide generation or transmission to serve those areas. If the state wanted to more aggressively promote alternatives to traditional generation and transmission infrastructure expansion, they could impose an additional fee in certain areas and redirect funds collected to promote or even subsidize DG within those areas.

In addition to making CHP more attractive to energy customers, the state must also make CHP more attractive to electric utilities. Under the current energy paradigm in Massachusetts, DG threatens to infringe upon utility profits because it is a substitute for grid-supplied electricity. Until the state changes rate structures to decouple utility profits from sales throughput, electric utilities will have little incentive to cooperate with DG development. But if a decoupling scheme were worked out that actually gave utility shareholders an incentive to permit DG on their distribution lines, we might actually see utilities taking the initiative to actively market DG to their customers. Since utilities would have the most insight into where and how to strategically install CHP to achieve system benefits, and they will likely not cooperate with this unless decoupling is carried out, decoupling should be one of the top priorities of state to promote CHP, DG, and sustainable energy generally.

Streamline, Standardize and Aggregate to Relieve *Complexity*, and Resolve *Compatibility*

CHP should not be subject to the same method of air quality permitting as traditional generation. Instead, a more streamlined permitting process with pre-approved, manufacturer guaranteed emissions ratings would decrease the complexity and cost of regulation. Also, emissions should be determined based on usable energy output, instead of fuel input. Doing so would reward the most efficient generators, including CHP. Additionally, CHP units should be given emissions credits for the boiler and furnace fuel combustion that is offset when steam is produced as a byproduct of electricity generation. Doing so would properly take into account the fuel efficiency of CHP, while still limiting the quantity of pollutants emitted to level that do not threaten human health.

Interconnection and CHP project management are very complex and require expertise to navigate. Although to some extent these challenges are inherent to DG, steps could be taken to make the development process run more smoothly. For example, it is unclear whether the existing DG interconnection tariff will induce DG installations that will contribute to significantly reducing carbon emissions. Since the uniform interconnection standards were adopted, the trend has been toward numerous solar PV DG systems with small capacity. While these pose minimal risk to the safety and reliability of the grid, they also are not significantly altering our course toward climate change or contributing to grid system benefits. The existing tariff may have been agreeable to the utilities, but perhaps regulatory action is needed to amend the tariff to make it more agreeable to potential DG customers. The tariff could be revised to be made more transparent and predictable. For example, grid impact studies should be conducted by independent third parties, and clear guidelines should be given for when customers would be responsible for paying for distribution upgrades. Doing so might allow curious developers to have a better idea of what costs and actions would be expected of them should they chose to pursue DG.

In order to overcome compatibility barriers to DG development, the state should promote programs to make DG more consistent with traditional business models and take regulatory action to reconcile DG with the goals of energy utilities. DG can be very capital intensive, with payback periods that are longer than other potential investment options. The revenue enhancement mechanisms described above can help increase the return on DG investment, but other financial products are needed that match the risk and payback profile of DG. For example, a public or private entity could use a large revolving fund to finance DG investment. This entity could work closely with energy service companies to analyze the cost, risk and performance profile of each DG investment. With third-party financing, DG would not have to compete against other company goals for limited capital. In fact, the Cambridge Energy Alliance (CEA), a non-profit public-private partnership headed by the Kendall Foundation, is working on developing just such a program to implement widespread energy efficiency measures, possibly including DG (Ribiero 2007). Boston and other cities are developing similar programs, and savvy lenders could even create comparable financial products to serve DG customers. The state should help coordinate and provide technical assistance to such programs.

In fact, utilities would be the ideal third party to aggregate and coordinate DG development since they know the technical capabilities of their distribution systems and power needs of their customers. Utilities could determine precisely where DG makes the most sense to maximize system benefits and help energy customers navigate the interconnection process.

The time is right for state policies to accelerate CHP development to reduce greenhouse gas emissions and help curb escalating energy costs. There is still ample opportunity to move toward Lovins' soft energy path. By identifying and addressing the specific barriers to CHP development, Massachusetts can lay the groundwork for greater deployment of distributed energy resources. By dealing with the biggest barriers to CHP, utility throughput incentive, interconnection and complexity, Massachusetts can make all types of DG easier and more cost effective to implement.

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