CARNEGIE MELLON UNIVERSITY

Electric Power Micro-grids: Opportunities and Challenges for an Emerging Distributed Energy Architecture

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Abstract

Distributed energy resources (DERs)[1] have become the focus of considerable research and investigation, as well as commercial interest in the U.S. and around the world. Despite a significant body of research that explores the potential benefits associated with DERs, several factors have combined to make progress toward serious adoption in the US very slow. These include: technical challenges; the absence of suppliers who can provide "turn-key" systems; real and perceived risks associated with the large-scale integration of DERs; the reluctance of legacy utilities to allow new entrants into markets in which, up until now, they have enjoyed a monopoly; and general deliberation and caution on the part of state utility regulators.

One emerging concept that holds considerable potential for improving the value of DERs is the micro-grid architecture, which builds on conventional continuous-use DER applications by aggregating and interconnecting small groups of customers onto a local grid. Some of the advantages of this kind of aggregation parallel the advantages of the centralized grid system – better resource utilization, increased redundancy and system robustness, and possible economies of scale. Other advantages include: increased levels of reliability, much greater net energy-use efficiency through the use of combined-heat-and-power applications, and increased customer choice and flexibility. Although progress has been made by both the regulatory and business community that has led to limited growth of conventional continuous-use DER applications, the micro-grid concept has yet to attract much commercial attention in the U.S.

Chapter 2 presents the results of the micro-grid customer engineering-economic model (MCEEM), developed by the author. In some cases, micro-grids can be good investments with current utility rate structures, reducing net present energy costs over a 25-year period by 5-10% in many of the cases studied and by over 20% in the best cases. The economic value of a micro-grid is shown to be greater for customers that have a value for highly-reliable electric power supply. The cost of natural gas and electricity is a significant factor in estimating the value of micro-grids, and continually rising natural gas prices may decrease their value, but other factors are also shown to be very significant. A sensitivity analysis reveals that the choice of micro-grid customer mix also has a large impact on

[1] Distributed energy resources can include generation, energy storage, and demand management. Distributed generation (DG) refers only to generation resources, such as engines and micro-turbines.

system economics, whereas climate plays only a modest role. Economies of scale are shown to be fairly modest for the scenarios studied, but micro-grids do show clear benefits over traditional single customer distributed generation (DG). If performance goals of current United States Department of Energy (US DOE) research programs for IC engines and micro-turbines are met, rates of return for micro-grid investments increase 10-20%.

In Chapter 3, the regulatory environment for micro-grids is examined using results from a survey of state regulatory officials conducted in Fall 2004. Only 17 of 27 participating states indicated that the installation and operation of a micro-grid is probably or definitely legal, and only under certain circumstances and subject to varying stipulations that make for an unattractive market environment. Among those 17 states, only 4 indicated that existing laws for the interconnection and operation of DERs would apply to micro-grid systems. No states have clear guidance for the regulatory oversight of micro-grid systems once they are installed, and most respondents indicated that such oversight would be conducted on a case-by-case basis. A series of recommendations for regulatory change are provided that could reduce uncertainty and lead to a much more hospitable environment for micro-grid market development.

Chapter 4 addresses the question of how electric utilities can best recover net costs from customer-generators. The problem of tariff design for customer-generators is introduced, with an overview of the competing goals of utility tariffs and the various mechanisms (i.e. tariff components) for cost-recovery. The various costs and benefits that customer-generators can impose on electric utilities are discussed, along with a framework for how both benefits and costs can and should be quantified and incorporated into the rate-setting process. Results from the MCEEM are presented that demonstrate how well (or poorly) different tariff components achieve the goals of a utility tariff, and the implications of these results are discussed. Standby rates are shown to increase customer peak period consumption by customer-generators, and represent a poor choice for cost-recovery in most cases. Increased demand charges are shown to be the best option for cost-recovery by utilities in most cases.

Chapter 5 examines the argument that a market based on DERs will have higher rates of innovation and new technology adoption than conventional, centralized supply. Data from the electricity industry are provided that demonstrate historically low rates of innovation and adoption. The characteristics that distinguish DERs from centralized supply – small size, dispersed resources, and modular design – are described, and relevant literature from the fields of economics and management science is discussed. This literature provides theoretical support for the claim that DERs will encourage greater innovative activity, but the claim is not tested empirically.

Acknowledgements

I would like to dedicate this thesis to my wife, Korin. She has been and continues to be a tremendous source of support, joy, and love. After all of the time she's spent listening to me and encouraging me she could probably write her own chapter on distributed energy resources, though I'm sure she shudders at the thought of it. Korin, I love you.

Granger Morgan deserves tremendous credit for the success of both my academic career and my relationship with Korin. Without his understanding and trust, this would have been a much harder road to travel. Granger's combination of intellect and wisdom make him unique, but it is his dedication that makes him an inspiration to me and so many others.

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EPP is so much like a family, and I'm so thankful that I've had the opportunity to spend time with so many sincere, motivated, and genuinely good people in the department. I have learned so much from my fellow graduate students, and shared many wonderful experiences in these short years. I will always remember my time in EPP fondly.

Finally, thank you to my friends and family for their ongoing support and love. I am unbelievably fortunate to be surrounded by so many wonderful people, and I hope you all realize how thankful I am to have you in my life.

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Chapter 1. Introduction

> *Several years ago the leadership at DTE tried to envision what the electric utility business would look like in a decade. One of our conclusions was that this industry would go through the same transformation that the computer business has experienced. There, mainframe computers gave way to desktops which gave way to laptops. We envisioned a day when the next step, distributed (or personal) generation, would play a major role.*
>
> – DTE Energy Chairman & CEO Anthony Earley Jr., 2005[2]

Distributed energy resources (DERs)[3] have become the focus of considerable research and investigation, as well as commercial interest in the U.S. and around the world. The US Department of Energy (US DOE) estimates that there were roughly 53 gigawatts of distributed generation in the US in 1998 (DOE 2000)[4]. This level of investment is the consequence of several major trends, including an increased value for reliable electric power; considerable improvements to both conventional DERs and important complementary technologies like solid-state controls; and an increased interest by policy-makers in encouraging competition and innovation in the electricity sector.

There is a substantial volume of research on the subject of DERs and their potential to provide various benefits to individual customers, the utility, and society. Some of the research on DERs is cited throughout this text, but two very useful reviews of the research related to DERs can be found in Iannucci et al. (2003) and Zerriffi (2004). A study by the California Energy Commission identified seventeen potential benefits and fifteen potential costs associated with DERs that have relevance to policy-making in the State (Gumerman et al. 2003). In their 2002 work *Small is Profitable*, Amory Lovins and others at the Rocky Mountain Institute catalogue over 200 benefits that can come from reducing the size of electrical resources (Lovins et al. 2002).

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[2] Quote from a presentation by Richard Seguin, Detroit Edison, IEPR Distribution Planning Workshop, April 29, 2005, as cited by CEC Report "Implementing CA's Loading Order for Electricity Resources" (CEC 2005).
[3] Distributed energy resources can include generation, energy storage, and demand management. Distributed generation (DG) refers only to generation resources, such as engines and micro-turbines.
[4] The Department of Energy defined distributed generation as generation of 50 MW or smaller. This is not the definition used in this thesis, but it does illustrate the large market that exists for small-scale electric power generation.

Among the most significant potential benefits of DERs are improved services and economic savings for customers, reduced environmental impact, avoided need for transmission and distribution capacity, increased competition and innovation, downward pressure on market prices, and improved utility system performance and security. Almost all of the purported benefits of DERs are contingent on utilizing the right kinds of resources in the right applications under the right conditions.

Although DERs are commercial products and they do not represent a substantial technological breakthrough (the most commonly adopted DER is essentially the same as a truck engine), they have received an uncommon level of attention from researchers. The biggest reason for this interest is that, from a technical and regulatory standpoint, the electric power industry has been managed in the same way for decades, and DERs pose significant risks and potential opportunities for an industry that is crucial to the US economy and way of life.

Despite a significant body of research that explores the potential benefits associated with DERs, several factors have combined to make progress toward widespread adoption in the US very slow. These include: technical challenges; the absence of suppliers who can provide "turn-key" systems; real and perceived risks associated with the large-scale integration of DERs; the reluctance of legacy utilities to allow new entrants into markets in which, up until now, they have enjoyed a monopoly; and general caution on the part of state utility regulators. As a consequence, there is a considerable burden of proof on advocates and researchers to demonstrate that DERs are worth the attention and focus of policy-makers.

There are various applications that DERs can be used for – the most common being back-up or standby power, which enables a customer to "keep the lights on" whenever the utility grid suffers a disturbance. Back-up generators represent the bulk of DER installations in the US, and they utilize resources such as diesel engines that are only designed to operate less than two hundred hours per year due to air quality concerns. DERs can also be used for continuous-use operation to provide most or all of the power to a single customer. In order to be cost-effective, continuous-use applications require the DER customer to be interconnected with the utility grid so that the customer can sell excess power to the utility and purchase power from the utility during peak periods or on-site system failures. It is the interconnection with and operation in parallel to the utility grid that has raised serious concerns for utilities and policy-makers, and the consequence has been the slow development and adoption of technical interconnection standards and interconnection procedures, as well as limitations on the number, size, and in some cases type of DER systems that can be interconnected.[5]

An emerging application for DERs is their use in a micro-grid system architecture, which builds on conventional continuous-use DER applications by aggregating and interconnecting small groups of customers on a local grid. Although the term "micro-grid" is used by different people to mean different things, I use the term throughout this paper to refer to a small group of customers, interconnected at low voltages on a local power grid with a single point of interconnection with the area electric power system (i.e. utility distribution grid). On-site distributed generation resources are integrated with the HVAC system to allow combined-heat-and-power applications, and the entire system (i.e. electricity and heat supply systems; interconnection switches) is managed with "smart controls" that ensure reliability and optimize operation to minimize costs.

The advantages of aggregation parallel the advantages of the centralized grid system – better resource utilization, increased redundancy and system robustness, and possible economies of scale. Like conventional DER applications, micro-grids are made more economical by interconnecting with the utility grid and consequently pose various technical challenges. Unlike conventional DER applications, micro-grids pose a perceived market threat to regulated electric utilities because electric power is exchanged from one customer to another within the micro-grid – a service that is currently restricted only to regulated utilities. The operation and control of resources on a micro-grid also represent increased internal technical challenges, in particular the optimal dispatch of multiple resources to multiple customers.

It is my belief that if DERs are ever going to reach their potential and yield the kinds of benefits that have been claimed, they will do so through the development and adoption of interconnected micro-grids with combined heat-and-power applications. The potential benefits that micro-grids could

[5] Interconnection rules are set separately for each state by their Public Utilities Commission (or equivalent). An updated overview of state-by-state rules is maintained by the Interstate Renewable Energy Council website, and can be found at www.irecusa.org/connect/statebystate.html (last visited May, 2006).

provide – reducing costs to customers, improving the efficiency of the energy supply, and driving competition and innovation – were the motivation for this work.

I have written the following chapters with several goals in mind. First, to shed light on the regulatory environment for electric power micro-grids, and identify both the major regulatory barriers to micro-grid development and some solutions that will facilitate this development. Second, to demonstrate that micro-grids can provide economic benefits to customers and are worth the attention of the regulatory community. Third, to provide potential investors and customers with a framework for analyzing the value that micro-grids can have, and insights into the primary factors that determine their value. Finally, to present and investigate one benefit that DERs may provide to society that has thus far been overlooked by analysts (even by the thorough work of the Amory Lovins and company) – the promotion of innovative activity and adoption of new technologies in a manner that large, centralized energy supply cannot.

The chapters of this thesis were written separately, and each is intended for academic publication. For this reason, there is some conceptual redundancy throughout the body of work, and the chapters do not always flow from one to the next. Each chapter should provide value independently and can be read separately.

Chapter 2, "A Customer-focused Assessment of Electric Power Micro-grids", provides a quantitative assessment of the value that micro-grids can have for individual groups of customers. This chapter introduces the micro-grid customer engineering-economic model (MCEEM), and provides results from the model, including: the value that micro-grids can have for different customer mixes in different locations across the US; the relative importance of different factors on micro-grid cost-effectiveness; the potential value of DER technology improvements; and a comparison of micro-grids with conventional DER applications. The robustness of these results is tested, subject to increased customer demand variability, and changing gas and electricity prices.

Chapter 3, "The Regulatory Environment for Interconnected Electric Power Micro-grids: Insights from State Regulatory Officials", provides an overview of the regulatory issues associated with micro-grids, drawing from a survey of state regulatory officials that was conducted by the author in Fall 2004. The results of the survey are discussed, and some of the most significant regulatory barriers are highlighted. The chapter concludes with some proposed solutions for facilitating micro-grid development.

Given the ongoing debate over rate-setting and cost-recovery methods for DER customers,[6] Chapter 4, "Utilities and Customer-Generators: The Effect of Tariff Design on Adoption and Management of Distributed Resources", addresses the question of how electric utilities can best recover net costs from customer-generators. This chapter introduces the problem of tariff design for customer-generators with an overview of the competing goals of utility tariffs and the various mechanisms (i.e. tariff components) for cost-recovery. The various costs and benefits that customer-generators can impose on electric utilities are discussed. A framework is proposed within which benefits and costs can be quantified and incorporated into the rate-setting process. Results from the MCEEM are presented that demonstrate how well (or poorly) different tariff components achieve the goals of a utility tariff, and the implications of these results are discussed.

Finally, in Chapter 5, "Innovation and Distributed Energy Resources: A Review of Relevant Literature", I investigate the argument that a market based on DERs will have higher rates of innovation and new technology adoption than conventional, centralized supply. Data from the

[6] The debate over the use of standby rates for DER customers has been held in academic literature and utility rate cases. Between May and November 2003, the Electricity Journal published three articles and one letter representing different perspectives on the subject of standby service and standby rates, ending with the aptly-titled piece "Standby rates issue is more nuanced than authors let on" (Casten 2003; Morrison 2003; Parmesano 2003a; Parmesano 2003b). The New York Public Service Commission (NYPSC) held a conference in Fall 2003 on the topic, pursuant to the NYPSC "Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms, and Conditions for the Provision of Electric Standby Service", Case 99-E-1470.

electricity industry are provided to demonstrate the historically low rates of innovation and adoption. The characteristics that distinguish DERs from centralized supply – small size, dispersed resources, and modular design – are described, and relevant literature from the fields of economics and management science is discussed.

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Chapter 2. A Customer-focused Assessment of Electric Power Micro-grids

2.1 Introduction

Electric power provision began as small independent grids serving just a few customers. Over the course of the past century, these small systems have grown and coalesced into a complex network served primarily by large generating plants whose power is distributed to customers via a high voltage transmission system and lower voltage distribution systems. While this architecture has served customers well, it faces several difficulties. First, there are limits to how reliable supply can be made and how well power quality can be controlled. Second, basic thermodynamics requires large central plants to dispose of enormous quantities of unused heat – typically half or more of all the heat they generate. As energy sources become scarce and more expensive, wasting that much heat is clearly not desirable, yet given the remote location of most generating plants there is rarely a viable alternative. Third, as restructuring has swept the industry, people have begun to think about whether there might be opportunities to introduce a competitive market, and the innovations that competition can bring, below the traditional distribution system at the customer level. All of these developments have sparked recent interest in distributed energy resources (DERs) which can serve single customers, and in micro-grids, which can serve a small group of co-located customers.

Although DERs offer numerous benefits, their adoption has been limited to emergency standby power and peak-shaving applications. As the demand for continuous-use DER applications continues to grow, technology innovations and learning curves can be expected to further improve their cost-effectiveness.

One emerging concept that holds potential to lower system costs and drive market penetration for DERs and associated energy services is that of the micro-grid. A micro-grid is a system architecture that builds on conventional DERs by assembling them into a small network that provides electric power, usually heat, and sometimes cooling to multiple co-located customers. By utilizing appropriate electronic controls and aggregating multiple customers, a micro-grid can combine some of the benefits of the traditional grid (e.g. aggregated demand, increased reliability, with the benefits of DERs (flexibility, customer control, increased efficiency through the use of waste heat).

First generation micro-grids rely on conventional DER technologies, particularly natural gas internal combustion engines and micro-turbines. In the future they may also make use of more advanced generating technologies such as fuel cells, or storage systems such as batteries or high-efficiency flywheels. The DERs are connected on a small internal network that typically has a single point of interconnection with the conventional power grid. Heat from the generators can be used for space conditioning, water heating, cooling, or industrial processes. Such applications are termed combined heating and power (CHP) or cooling and power (CCP).

In order to maximize system reliability, a micro-grid can be designed to operate as an island when the utility grid experiences outages, and the DERs can be arranged so as to ensure that critical loads on the micro-grid are not interrupted (Lasseter et al. 2002). Once distribution system automation becomes more sophisticated, micro-grids and other DERs could also be used to provide support for the utility grid in times of system stress (Zerriffi 2004).

The emergence of the micro-grid concept has coincided with considerable legislative and regulatory activity aimed at opening up electricity markets and encouraging innovation and flexibility. Such activity includes FERC Order 2006 relating to Standardization of Small Generator Interconnection Agreements and Procedures, Section 1254 of the Energy Policy Act of 2005, as well as various state rules (MI PSC Docket U-13745; MN PUC Docket E-999/CI-01-1023; NY Docket 02-E-1282; TX Project No. 21220; and WI Admin. Code Chapter PSC 119). Unfortunately, despite the potential benefits of micro-grids, little has been done to improve or even clarify the regulatory environment for micro-grid systems. Recent surveys of state regulatory officials in the U.S. have shown that micro-grids are still not formally defined in state regulatory law, and are typically subject to case-by-case interpretations of laws that were written primarily for the protection of utilities and their customers (Morgan and Zerriffi, 2002 ; King 2005).

In the regulatory context, micro-grids are primarily defined by how they make money, who they serve, and how they interact with the incumbent electric utility. In most states, "exclusive service territory" provisions can be used by incumbent utilities and others to discourage or prohibit micro-grids. Given this, and the fact that state Public Utility Commissions have a limited ability to innovate, but must wait to react to formal legal challenges, the most efficient way to clear these legal obstacles is likely to be new legislation [King and Morgan, 2003].

While there are free-standing micro-grids in parts of the developing world, interconnected micro-grids are still quite rare. This results from regulatory uncertainty, the fact that the concept is unfamiliar to most architects and builders, as well as from various technical complications (Lasseter et al. 2002; Feero et al. 2002; Hatziargyriou 2006). Today, there are just a handful of operational interconnected micro-grids in the United States and only modest numbers in other parts of the world. Many of these are demonstration projects (see Barnes et al. 2005 for an overview of several European demonstrations, and the New Energy and Industrial Technology Development Organization for information on Japanese demonstrations). However, there is considerable ongoing research into the micro-grid concept worldwide. Two research consortiums in particular have produced significant work on the technical and economic issues associated with electric power micro-grids: the Consortium for Electric Reliability Technology Solutions in the US, which is funded by the US Department of Energy (US DOE) and the California Energy Commission; and the European Project Cluster "Integration of RES and DG", which is funded by the European Commission.

Before investing significant effort in alleviating regulatory obstacles, we should ask whether and under what circumstances micro-grid systems can be valuable to customers, and where targeted investments in long-term research and development and short-term niche commercialization can be worthwhile. Accordingly, this chapter: 1) presents a method for optimizing the decision-making of potential micro-grid customers; 2) estimates the potential economic benefits that micro-grids can provide to customers; 3) determines the relative significance of different factors that affect the economic viability of individual micro-grid projects, including climate, customer mix, and system scale; and 4) assesses the potential impact that changes in energy markets or technology development may have on micro-grids.

This chapter begins with a description of the engineering-economic model used for evaluating micro-grids. In Section 2.3, I perform a baseline analysis estimating the net economic benefits of micro-grids for six different prototypical groups of customers in six US cities using real-world gas and electricity prices. In Section 2.4, the results of a sensitivity analysis are presented identifying the factors that drive the cost-effectiveness of micro-grids. In Section 2.5, I examine the potential benefits that could be gained from innovation in micro-grid technologies. In Section 2.6, I compare the value of the micro-grids architecture to that of traditional DER applications. Finally, I conclude with an overview of the results and their meaning for policy-makers and potential micro-grids customers.

2.2 Model Description

The results presented in this chapter are the output of what I call the micro-grid customer engineering-economic model (MCEEM). The model, constructed in Visual Basic, simulates the decision-making of rational micro-grid owners and operators who seek least-cost solutions. Conceptually, the model parallels the Distributed Energy Resources Customer Adoption Model (DER-CAM), created by researchers at Berkeley Labs (Marnay et al., 2001; Rubio, et al. 2001), in that it provides realistic estimates of the economic costs and benefits to micro-grid customers. Methodologically, it diverges from DER-CAM with respect to the construction of the model, the optimization routines utilized, and the specific sources and types of inputs used. Unlike DER-CAM, which integrates both capital and dispatch problems into one optimization routine, the MCEEM nests the hourly dispatch optimization within the configuration (generation mix) optimization, using the results of the former to inform the latter (Figure 1). While DER-CAM is constructed in the General Algebraic Modeling Systems software and makes use of conventional optimization methods, the optimizations within the MCEEM rely on comprehensive search loops to characterize the entire multi-dimensional space and identify the least-cost solutions. DER-CAM also includes various features, such as tiered pricing and an expanded equipment list that make it more flexible for work beyond the scope of the MCEEM.

The approach used in the MCEEM reduces some of the sub-optimality that comes from using a linear optimization method on a problem with various non-linearities and discontinuities, but it is also slower and less transparent.

Optimization routines created for this work were written for steady-state conditions (e.g. known, fixed prices, predictable demand, and technology specifications), but algorithms could be designed for dynamic conditions that allow a micro-grid to be responsive to changing hourly price signals, grid stability, etc. All results reported are in terms of net present values (NPV).

The MCEEM estimates the maximum cost-savings (if any) that a given customer will enjoy by installing and operating a micro-grid, as compared to buying all electricity from the distribution utility and providing space and water heating with a conventional heating system.

- Model inputs include: hourly electric and heating (water and space) demand profiles for a full year; equipment costs (capital and operation and maintenance) and specifications (capacity, heat-to-power ratio, efficiency curves; availability); and economic information (discount rates, gas and electricity rates and tariff structures).
- Model outputs include: lifecycle cost savings in net present value and internal rates of return (IRR); optimal micro-grid configuration (number, type, and capacity of generation assets, size of auxiliary boiler); system capital and annual operating costs (maintenance and fuel) for the generators and auxiliary boiler; and hourly production and buy/sell decisions.

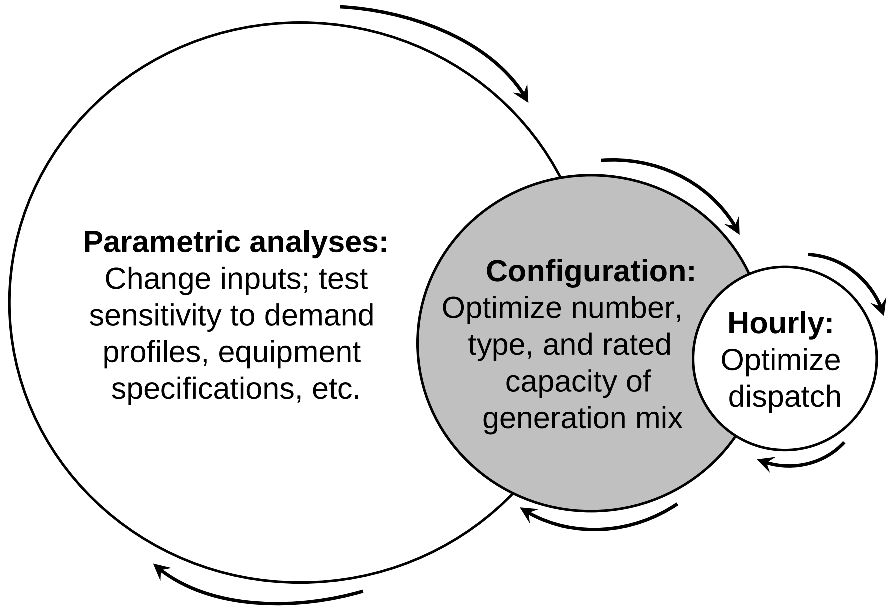


Figure 1. Illustration of the nested optimization routines used in the Micro-grid Customer Engineering Economic Model used for this analysis.

Equipment specifications (capital costs; operation and maintenance costs; efficiency curves) used in the model were provided directly by manufacturers and compiled by Oak Ridge National Lab (Oak Ridge National Lab 2004). All generating and heating equipment in the model is natural gas-fired.

In order to increase the robustness of the results and test the most significant determinants of economic success for micro-grids, the MCEEM was run for various mixes of customers in different locations. I use the term scenario to refer to a specific customer mix in a specific location. For a given scenario the model tests a series of configurations, and for each configuration the model optimizes micro-grid operation for a full year, subject to the constraints of the configuration.

The net present cost for each configuration is determined based on capital, operating (including fuel, operation and maintenance) and utility costs. A 10% discount rate is used and the system life is assumed to be 25 years. The configuration with the lowest net present cost is considered optimal and the cost for this configuration are compared with the net present cost of an identical conventional, non-generating customer mix over the same period to determine the NPV of installing a micro-grid. It is not assumed that a micro-grid will save money, so in some cases the optimal configuration is to install no micro-grid and purchase 100% of the electricity from the utility and supplying heating and cooling through conventional HVAC systems.

The model performs two optimizations: micro-grid configuration and design; and hourly dispatch (Figure 1). The inputs provided for parametric or sensitivity analyses are exogenous to the configuration optimization, and the parameters defined in the configuration optimization are exogenous to the hourly dispatch optimization.

2.2.1 Hourly dispatch optimization

The objective function in the hourly optimization is to minimize total system costs (*TC*, equation 1) subject to the equality constraint that electric demand must be met by micro-grid generation and/or utility supply (equation 2), and the inequality constraints that power dispatched from each generator must be non-negative and may not exceed rated capacity (equation 3), and the sum of the captured generator waste heat output and the auxiliary boiler heat must equal or exceed system heat demand (equation 4). Total cost is a function of generator dispatch (p_i, where i refers to a specific generator), power bought from the utility (p_{buy}), and heat produced by the auxiliary boiler (ht_b). The latter two variables are treated as slack variables, and all other parameters are treated as constants in the hourly optimization. This optimization is performed for each hour in a year.

The following formulation is a representation of the optimization routine:

Input parameters

Parameter

k = constant conversion factor for electric to thermal units (0.003413 MBTU/kWh)

n = number of generators on the system

P_e = price of electricity from the utility ($/kWh)

P_{gas} = price of natural gas ($/MBTU)

P_b = "buy-back" price of electricity paid by the utility ($/kWh)

λ = contribution to monthly demand charge

HPR_i= heat-to-power ratio

α_i, β_i, γ_i = coefficients of the generator efficiency curves

Cap_i = rated capacity of each generator (kWh)

Eff_{elec_i} = electrical efficiency at rated capacity

Eff_b = thermal efficiency for the auxiliary boiler

ht_{demand} = hourly heat demand (MBTU)

p_{demand} = hourly power demand (kWh)

Decision variables

ht_i = useful heat captured by each generator (MBTU)

ht_b = heat produced by the boiler (MBTU)

p_i = power produced by each generator (kWh)

p_{buy} = power bought from the utility (kWh)

p_{sell} = power sold to the utility (kWh)

Mathematical formulation

$$\min TC = \underbrace{\sum_{i=1}^{n} Cop_{gen_i}}_{\substack{generation\\cost}} + \underbrace{Cop_b}_{\substack{boiler\\cost}} + \underbrace{P_e \times p_{buy} - P_b \times p_{sell}}_{\substack{utility\\charges}} + \underbrace{\lambda}_{\substack{demand\\charge\\cont.}} \tag{1}$$

Subject to:

$$p_{demand} = p_{buy} - p_{sell} + \sum_{i=1}^{n} p_i \tag{2}$$

$$0 \le p_i \le AvCap_i \tag{3}$$

$$ht_{demand} \le ht_b + \sum_{i=1}^{n} ht_i \tag{4}$$

$$Cop_{gen_i}(p) = C_{ratedfuel_i}\left[\alpha_i + \beta_i \frac{p_i}{Cap_i} + \gamma_i \left(\frac{p_i}{Cap_i}\right)^2\right] + C_{maint_i} \times p_i \tag{5}$$

$$C_{ratedfuel_i} = \frac{Cap_i \times k \times P_{gas}}{Eff_{elec_i}} \tag{6}$$

$$Cop_b = \frac{ht_b \times P_{gas}}{Eff_b} \tag{7}$$

where $AvCap_i$ is available capacity for each generator and equals either Cap_i or 0 in each hour; ht_i is the available waste heat from each generator and equals p_i x HPR_i; $Cop_{gen\ i}$ (equation 5) is the operating cost of each generator; $Cratedfuel_i$ (equation 6) is the fuel cost of operating each generator; and Cop_b (equation 7) is the operating cost of the auxiliary boiler. The demand charge contribution λ is not considered part of the total hourly cost – it is a way to represent the contribution of hourly demand to the monthly utility demand charge in the optimization; λ is equal to either zero (when reducing demand will have no effect on the monthly demand charge) or DC/j where DC is the utility demand charge ($/kW) and j is the number of peak period hours in the month with equal or greater avoidable demand. Future demand is assumed to be predictable and used to inform the value of j within the optimization.

This optimization could best be solved using a quadratic programming approach, but since the optimization is run 8,760 times per configuration, that approach was abandoned due to computational constraints. Instead, the optimization is solved by checking each of the corner-points in the multi-dimensional space. A sample comparison showed that this method produces the optimal dispatch in most hours, and in others results are within 10% of the optimum. This level of sub-optimality has a small effect – probably less than a few percent – on the overall results.

Each hourly optimization is solved independently. Some conditions (heat and electricity demand, generator availability) change hourly, but most parameters are fixed as a function of the configuration. Treating each hour as independent simplifies the dispatch optimization by ignoring start-up and shut-down costs. While these costs are significant in large systems, they are generally small for DG units, especially internal combustion engines.

2.2.2 Configuration optimization

Since engines and micro-turbines experience non-linear economies of scale[7], the multi-dimensional space that defines the system configuration is very irregular and not conducive to traditional optimization routines. In order to avoid the problems posed by local minima and maxima, the MCEEM maps the entire cost surface of the multi-dimensional space, with the result that each scenario requires hundreds or thousands of different configurations to be modeled.

[7] Plots for installed capital cost as a function of rated capacity were derived from manufacturer's data (EIA 2003), and are presented in the Figure A1 in Appendix A.

The MCEEM allows between zero and ten generators per configuration, with a mix of natural-gas fired micro-turbines and engines. The maximum rated capacity for each generator on the system is limited only by technology constraints (e.g. micro-turbines are manufactured up to 600 kW) or demand (i.e. generation could not exceed maximum peak annual demand). Step size for generator capacity is limited to keep the analysis computationally feasible. It is assumed that a micro-grid customer will build the micro-grid in a configuration that minimizes the total system net present cost (*NPC*):

$$\min NPC = DF \times \left(\underbrace{\sum_{h=1}^{8760} TC_h}_{\substack{\text{sum of}\\ \text{hourly}\\ \text{costs}}} + \underbrace{\sum_{m=1}^{12} p_{peak_m} \times DC}_{\substack{\text{monthly}\\ \text{demand}\\ \text{charges}}} \right) + \underbrace{\sum_{i=1}^{n} Ccap_{gen_i} + Ccap_{boiler} + Ccap_{int}}_{\substack{\text{capital}\\ \text{infrastructure}\\ \text{costs}}} \tag{8}$$

Where *TC* is the total operating cost in each hour (equation 1); *DF* is the discount factor; p_{peak} is the peak demand for each month; *DC* is the utility demand charge; $Ccap_{gen}$ is the capital cost for each generator on the system; $Ccap_{boiler}$ is the capital cost of the auxiliary boiler; and $Ccap_{int}$ is the cost of interconnecting with the utility grid.

2.2.3 Scenario analysis

Since the goal of this work is to assess the economics of micro-grids for a variety of customers and conditions, 36 different micro-grid scenarios were devised by considering six different micro-grid applications (Table 1) in six different US locations (Table 2).

Table 1. Description of Micro-grid Customer Mixes Modeled	
Customer mix	Description
High-rise office	One large building (630,000 ft^2 total) that includes mostly office space, with some restaurant and retail space, and a parking garage
Hospital complex	Five buildings (414,000 ft^2 total), including one large hospital building, two small hospital buildings, one small office building, and one large hotel or other residential building, and a parking area
Indoor Mall	One large commercial building (590,000 ft^2 total) that includes a movie theatre, retail and restaurant space, and a parking garage
Office complex	Five buildings (1,018,000 ft^2 total) that include mostly office space, with some food and retail space, as well as a parking garage
Strip mall	Four separate small commercial buildings (400,000 ft^2 total) that include mostly retail space, along with a large supermarket, a movie theatre, restaurants, and a parking area
Urban commercial / residential mix	Three buildings (120,000 ft^2 total), including one large hotel building, two commercial buildings, and a parking area

Table 2. Description of Micro-grid Locations Modeled	
Location	Description*
Miami, FL	Warm, humid (200 HDD, 55 inches of precipitation annually)
San Diego, CA	Warm, dry (1,076 HDD, 12.5 inches)
Little Rock, AR	Moderate, humid (3,155 HDD, 55 inches)
Richmond, VA	Moderate, somewhat humid (3,963 HDD, 45 inches)
Minneapolis, MN	Cold, somewhat humid (7,891 HDD, 32.5 inches)
Burlington, VT	Cold, somewhat dry (7,903 HDD, 27.5 inches)

* HDD refers to annual heating degree days – a common metric for comparing climate in different places. In this case, HDD are quoted from the Department of Energy's typical meteorological year (TMY) data.

Hourly electric and heat demand profiles were generated for each scenario using the DOE-2.1 back-end of Oak Ridge National Lab's (ORNL) BCHP Screening Tool (ORNL 2004). Each building on the micro-grid was modeled separately and the results were aggregated. These demand profiles became inputs for the MCEEM. Tables 3 and 4 summarize the demand associated with different customer mixes (averaged over all six locations) and micro-grids in different locations (averaged over all six customer mixes).

Table 3. Comparison of Demand Characteristics for Different Customer Mixes

	High-rise building	Hospital complex	Indoor Mall	Office complex	Strip mall	Urban mix
Avg. demand, kW	897	1,177	979	1,426	682	197
Peak demand, kW	2,855	2,073	2,393	4,517	1632	437
Avg. electric density (W / ft^2)	1.380	2.843	1.659	1.401	1.705	1.642
Avg. heat density (W_{th} / ft^2)	0.273	1.310	0.210	0.309	0.427	1.233

Table 4. Comparison of Demand Characteristics for Micro-grids in Different Locations

	Miami	San Diego	Little Rock	Richmond	Minneapolis	Burlington
Avg. demand, kW	1,119	894	918	864	794	766
Peak demand, kW	2,458	2,128	2,483	2,387	2,272	2,170
Avg. electric density (W / ft^2)	2.103	1.680	1.726	1.624	1.492	1.440
Avg. heat density (W_{th} / ft^2)	0.254	0.270	0.373	0.449	0.722	0.706

The validity and realism of DOE-2 model demand profiles were verified by comparing model results to real-world consumption data gathered by the US DOE Commercial Building Energy Survey (EIA 2003), presented in Table 5. The robustness of this method is tested again later in the chapter with an analysis that explores how variations from the values estimated by the DOE-2 model might affect the results of the baseline analysis.

Table 5. Comparison of Model Estimated Demand and Surveyed Real-world Demand

	Load factor (25^{th} – 75^{th} percentile)		Electricity density (mean Watts / ft^2)	
Building type	Real world average*	MCEEM demand profiles	Real world average*	MCEEM demand profiles
Hospital / health care	34 – 74 %	52 – 66 %	3.03	2.84
Indoor mall	33 – 68 %	38 – 47 %	1.35	1.66
Strip mall	21 – 44 %	39 – 49 %	1.35	1.71
Urban mix	36 – 59 %	41 – 54 %	1.74	1.64
Office / high-rise	39 – 74 %	28 – 38 %	2.16	1.40

* Data representing real world averages come from the Department of Energy Commercial Building Energy Survey (EIA 2003).

2.3 Baseline Results

I first estimate what a micro-grid would be worth to potential customers in an open marketplace. In this analysis, real-world technologies, gas and electric rates, and consumers are considered, and micro-grid owners/operators are assumed to make economically optimal decisions about installation and operation. It is assumed that the micro-grids have automatic controls that optimize production and consumption under changing conditions. This analysis was conducted from 2003-2004, so the inputs and results are representative of that timeframe.

Table 6. Natural Gas and Electric Power Rates for Commercial Customers

City	Natural gas rates* ($/MBTU)	Electric rates** ($/kWh) summer / winter	Demand charges ($/peak kW) summer / winter
Miami, FL	$ 10.50	$0.050 / $0.050	$8.00 / $8.00
San Diego, CA	$ 7.75	$0.115 / $0.110	$16.00 / $14.00
Little Rock, AR	$ 8.50	$0.020 / $0.015	$8.50 / $7.50
Richmond, VA	$9.75	$0.025 / $0.020	$14.00 / $3.00
Minneapolis, MN	$ 7.50	$0.035 / $0.065	$9.50 / $6.50
Burlington, VT	$ 8.25	$0.070 / $0.075	$11.00 / $13.50

* Commercial gas prices – Energy Information Administration, 2003 data
** Rates provided by local utilities in each area, accordingly: Burlington – Miami – Florida Power & Light; San Diego – San Diego Gas & Electric; Little Rock – Entergy Energy; Richmond – Dominion Power; Minneapolis – Xcel Energy; Burlington Municipal Electric Department. All rates are from 2003.

Electricity rates are based on 2003 commercial tariffs provided by area electric power utilities, and gas prices are based on US Energy Information Administration data for 2003 (Table 6). It is assumed that micro-grid customers face the same rates as normal commercial customers, but details of the tariff structures (e.g. tiered pricing, ratcheting) were not included in this analysis.

It is unclear what kind of rates a real micro-grid would face. In some states, utilities are required to grant tariffs to customer-generators that are competitive or even favorable compared with those granted to conventional customers. On the other hand, due to a lack of specific regulatory law or guidance for micro-grid systems, these tariffs may not be applicable and utilities may be able to create tariff structures ad-hoc. The buy-back rate paid by the utility for power exported from the micro-grid is assumed to be $0.03, based on typical utility tariffs.

The results of the baseline analysis are shown in Table 7. The conclusions are mixed. The model predicts that typical customers will not choose to install micro-grids in Little Rock, AK, Richmond, VA, and Miami, FL. In Minneapolis, MN the optimal micro-grid would meet a small fraction of the electricity demand. These systems are profitable primarily by serving baseload electric and heat demand and as peak-shaving systems. Micro-grids in Burlington, VT for the hospital complex, urban mix, and office complex applications have reasonable value, saving approximately 8%, 7% and 6.5% of the total energy costs (in NPV) over the life of the project and providing more than 60% of the annual electricity consumption. In San Diego, CA where electricity prices are very high, micro-grids can yield exceptional value with an overall savings of more than 18-26%, and rates of return well above 20%. These systems meet most of the customer demand, requiring their customers to purchase electricity only during routine maintenance or if the micro-grid experiences a failure.

Table 7. Results from Baseline Analysis

City	Customer mix	Installed capacity (kW)	Savings* ($)	Savings** (%)	Monthly savings* ($)	Internal rate of return	Electricity purchased (%)
Miami, FL	*None of the micro-grids in Miami, FL are cost-effective in the baseline analysis*						
San Diego, CA	Office Complex	4,200	$ 5,019,000	25.7%	$ 45,611	25.6%	4%
	Strip Mall	1,600	$ 1,627,000	18.9%	$ 14,780	22.2%	8%
	Hospital Complex	2,000	$ 3,453,000	23.7%	$ 31,382	31.7%	4%
	High-rise	2,700	$ 2,697,000	21.9%	$ 24,503	22.3%	3%
	Indoor Mall	2,350	$ 2,575,000	20.5%	$ 23,398	22.5%	2%
	Urban Mix	350	$ 478,000	17.5%	$ 4,345	21.4%	6%
Little Rock, AR	*None of the micro-grids in Little Rock, AR are cost-effective in the baseline analysis*						
Richmond, VA	*None of the micro-grids in Little Rock, AR are cost-effective in the baseline analysis*						
Minneapolis, MN	Office Complex	150	$ 14,000	0.1%	$ 125	10.8%	96%
	Strip Mall	100	$ 10,000	0.2%	$ 89	10.9%	93%
	Hospital Complex	400	$ 141,000	1.8%	$ 1,283	13.2%	79%
	High-rise	50	$ 5,000	0.1%	$ 43	10.9%	98%
	Indoor Mall	100	$ 4,000	0.1%	$ 33	10.3%	96%
	Urban Mix	50	$ 11,000	0.7%	$ 99	12.0%	87%
Burlington, VT	Office Complex	3,500	$ 856,000	6.4%	$ 7,779	13.5%	39%
	Strip Mall	300	$ 139,000	2.3%	$ 1,259	14.1%	82%
	Hospital Complex	1,600	$ 796,000	7.7%	$ 7,233	16.1%	37%
	High-rise	1,550	$ 340,000	4.1%	$ 3,092	12.8%	59%
	Indoor Mall	350	$ 152,000	1.8%	$ 1,384	13.9%	88%
	Urban Mix	200	$ 140,000	6.9%	$ 1,272	16.1%	43%

* Net present energy costs saved by installing a micro-grid, using a 10% discount rate and a project lifetime of 25 years.
** Percentage of total energy lifetime costs (in net present value) saved by installing a micro-grid.

These results indicate that although micro-grids are not cost attractive to all customers in all locations, they can be very cost attractive in certain circumstances. As discussed later in the chapter, customers that have special needs or a high value for reliability or power quality will find micro-grids more attractive, but those considerations are not included in the present analysis.

I will further explore why certain applications show better economic returns than others in a later section, but the baseline results demonstrate clearly that both natural gas and electricity prices are important drivers. In fact, state average "spark spreads" – the margin between average electricity prices and average natural gas prices – do have some explanatory power here. Based on 2003 EIA data for commercial customers, California and Vermont had the 3rd and 4th highest average spark spreads, respectively. On the other hand, Minnesota ranked 36th, Florida 41st, Arkansas 45th and Virginia 49th. States with fairly high spark spreads (e.g. all of the northeast, AK, HI, NV, TX, and PA) will likely show strong positive results similar to those of California and Vermont.

It is important to note that "spark spread" is not a sufficient explanation for the results, as some regions and customer mixes are more sensitive to changes in electricity prices than gas prices. Also, as will be discussed, customer mix plays a very significant role; for example, the Minneapolis hospital complex provides the same savings (1.8%) as the Burlington indoor mall (1.8%), despite the fact that Burlington has a much higher spark spread than Minneapolis.

The link between energy prices and micro-grid value is not surprising, but it does mean that if micro-grids customers were able to procure lower natural gas prices through contracts or state-mandated tariff arrangements, they could be even more attractive. Such a scenario is not unlikely, considering that large industrial and utility customers are often able to negotiate lower rates. Regulators in both New York and New Jersey have required natural gas companies to analyze the impact that customer-generators have on their distribution costs, and possibly offer lower rates (NJBPU 2003; NYPSC 2003). On the other hand, if utilities are given the ability to set discriminatory rates for customer-generators, then micro-grids will be made less attractive. Rising natural gas prices will also have a significant affect on the value of micro-grids, as will be discussed later.

2.3.1 Valuing reliability

The pursuit of highly reliable, high-quality power is expected to be one of the primary motives for early micro-grid adopters. Many types of customers – especially those that provide critical medical, emergency, security, financial, or communications services – presently invest in back-up generation capacity that is rarely utilized. These customers, along with select industrial and commercial customers, explicitly or implicitly value highly reliable electric service and are among the most likely candidates for early adoption.

A 2001 review of 117 recent documents on electric reliability valuation (Eto et al. 2001) describes several different ways to estimate the value of reliability, and provides data from various sources on the cost of electricity failures. Clemmensen (1993) estimates that 1.5 to three percent of every manufacturing sales dollar is spent correcting power quality problems. Estimates for the total cost to the economy of power quality and reliability problems ranged from $15-30 billion, to $25 billion, $50 billion, $150 billion, and $400 billion per year. One study suggested that more than $1 billion is spent annually on uninterruptible power supplies, and another estimates over $5 billion on power quality equipment and services.

A micro-grid can be designed and operated to maximize reliability or improve power quality under various states of instability (Lasseter et al. 2002). Customers with a high value for reliability and/or power quality will make decisions differently than those modeled in the baseline analysis, depending on the shape of their demand curve for high quality, highly reliable electric power. These customers are likely to install larger systems than ordinary customers and the economics is likely to be more favorable.

In order to understand how this value for reliability could affect the value of a micro-grid, I considered customers that would install generating capacity for back-up power regardless of whether it's organized in a micro-grid. For these kinds of the customers, it is assumed that the "cost to compare" is the same as a conventional customer but with the added expense of back-up generating capacity. I tested two cases: in the first, it is assumed that the customer would install back-up capacity equal to average hourly demand; in the second, it is assumed that the customer would install back-up capacity equal to average peak period demand. The former is typical of a customer with few critical loads, while the latter is typical of a customer with large critical loads.

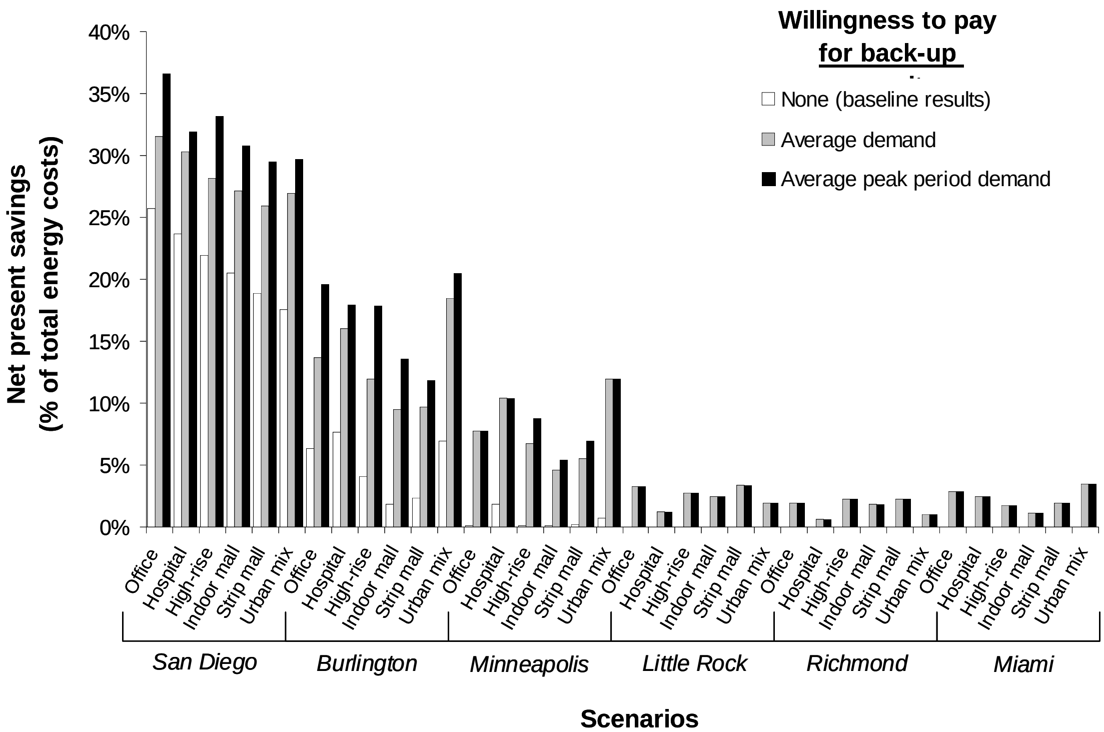


Figure 2. A comparison of the economic savings from installing and operating a micro-grid, for customers with different willingness to pay for back-up capacity. Customers that have a high value for reliability are more likely to install back-up capacity to protect critical loads. Such customers will experience a greater value from installing a micro-grid.

Figure 2 demonstrates the effect that customer value for reliability and power quality has on the economic value of micro-grids. Customers that are willing to buy back-up capacity for reliability purposes experienced higher returns in all 36 scenarios. In many scenarios – including those in Little Rock, Miami, and Richmond – a willingness to pay for reliability changed the economics enough to motivate customers to invest in micro-grids when they otherwise would not.

The results presented in Figure 2 are representative for customers that value having back-up or stand-by power in the case of a transmission or distribution system failure. Generally, as customer value for reliability (or power quality) increases, the relative economic value of a micro-grid increases. However, this trend may tail off for customers, or more likely very specific loads, that require "super-reliable" power. For highly essential loads, customers may require fuel storage, redundancy, uninterruptible power supplies, and/or other assurances of power reliability and quality.

2.3.2 Combined cooling and power

One proposed way to improve the value of a micro-grid is to use generator waste heat to reduce cooling loads through the use of absorption or adsorption chillers or desiccants (Bailey, et al. 2002; Wang and Oliveira 2005). Modern conventional chillers have coefficients of performance (COP, which is the ratio of MBTU output to input) of between 5 and 6 (Rocky Mountain Institute 1997). Traditional single-effect adsorption and absorption chillers only have COPs equal to roughly 0.6-0.7 (Bailey, et al. 2002; Wang and Oliveira 2005), which means that for every kW of useful heat that is captured for CCP, roughly 0.1-0.2 kW of cooling from the chiller is avoided. By contrast, boilers are only 75-85% efficient, so for every kW of useful heat captured 1.2-1.3 kW of heating is avoided.

First-order calculations suggest that because of the difference in efficiencies between a conventional chiller and an absorption or adsorption chiller, conventional CCP applications will likely have a modest effect on the economics of a micro-grid. During hours with very large cooling loads, using CCP can reduce the electricity demand by roughly 10%, which is the same as effectively increasing the operating efficiency of the DERs by 1/10th. This kind of improvement is enough to slightly improve the economics for micro-grid scenarios that are already cost-effective and change decisions that are close, but is not likely to significantly alter decision-making.

CCP may still prove very valuable for customers that require a lot of cooling – especially if multiple-effect chillers continue to improve. The next generation of multiple-effect absorption chillers have COPs of up to 1.3 (Rocky Mountain Institute 1997), which could have a significant effect on the value of CCP in micro-grids.

2.3.3 Provision of Ancillary Services

Although the primary role of a micro-grid is to meet the electricity and heating needs of its customers, it can also provide value to grid operators through the provision of ancillary services such as voltage support and operating reserves. The value that these services have to a utility may depend on the details of the local grid, and establishing that value may require bi-lateral contractual agreements. In many parts of the country, particularly where these services are most highly valued due to generation and distribution capacity constraints, the provision of ancillary services has been formalized through the creation of open markets. Table 8 shows information for ancillary service markets managed by three different Independent System Operators (ISO).

Table 8. Ancillary Services Market Clearing Price
(average hourly $/MW, 2004)[8]

ISO	Regulation	Synchronous spinning reserves	Non-spinning operating reserves
NYISO	$ 22.60	$ 2.40	$ 0.30
PJM	$ 32.60*	$ 7.40	$ 0.23
ERCOT	$ 10.30	$ 7.60	$ 2.40

* Regulation data is from PJM's mid-Atlantic zone

[8] Although 2005 energy market prices increased considerably over 2004, ancillary service market prices for the first half of 2005 do not show a consistent increase.

In the case of spinning and operating reserves, micro-grid owners/operators may be able to generate extra revenue by bidding their excess capacity into these markets. The precise value that market participation will depend on how much and how frequently the micro-grid has excess capacity, and the going price on the regional market. Also, the clearing price is likely to drop if many customers with DERs begin participating in these markets, so relying on ancillary markets for considerable revenue could be very risky. Nonetheless, providing ancillary services in this way could further improve the economics of micro-grids while also making the local grid more robust.

Table 9 shows some first-order estimations of the value that ancillary service market participation could have for micro-grid owners/operators. This data represents the value that a micro-grid owner/operator would experience if all excess capacity was sold into an ancillary service market. All of the baseline conditions were maintained, and it was assumed that micro-grid operators could accurately predict on-site demand and therefore sell any excess capacity on day-ahead markets. In reality, the value of participating in ancillary service markets will vary considerably by locale, so selling capacity in the New York City area will yield much higher returns than those presented here, but selling capacity in rural Idaho will yield much lower returns.

Table 9. Impact of Participation in Ancillary Services Markets, Select Results (Savings in $'s, Savings in %, and Internal Rate of Return)

City	Customer mix	Baseline	Non-spinning reserves (assume $0.30/MWh)	Spinning reserves (assume $7/MWh)
San Diego,	Hospital Complex	$3,453,000	$3,470,000	$3,853,000
CA		24.2%	24.3%	27.0%
		31.7%	33.6%	35.9%
	High-rise	$2,697,000	2,734,000	$3,569,000
		21.9%	22.2%	29.0%
		22.3%	22.4%	26.0%
	Indoor Mall	$2,575,000	$2,603,000	$3,212,000
		20.5%	20.7%	25.5%
		22.5%	22.6%	25.4%
	Urban Mix	$478,000	$481,000	$544,000
		17.5%	17.6%	19.9%
		21.4%	21.5%	22.9%
Minneapolis,	Hospital Complex	$141,000	$144,000	$208,000
MN		1.8%	1.8%	2.6%
		13.2%	13.2%	14.6%
	High-rise	$5,000	$6,000	$19,000
		0.1%	0.1%	0.3%
		10.9%	11.0%	13.4%
	Indoor Mall	$4,000	$5,000	$31,000
		0.1%	0.1%	0.5%
		10.3%	10.4%	12.8%
	Urban Mix	$11,000	$11,000	$20,000
		0.7%	0.7%	1.2%
		12.0%	12.1%	13.5%
Burlington,	Hospital Complex	$796,000	$815,000	$1,242,000
VT		7.7%	7.9%	12.0%
		16.1%	16.2%	19.3%
	High-rise	$340,000	$366,000	$947,000
		4.0%	4.4%	11.3%
		12.8%	11.3%	17.6%
	Indoor Mall	$152,000	$157,000	$261,000
		1.8%	1.9%	3.1%
		13.9%	14.0%	16.5%
	Urban Mix	$140,000	$142,000	$183,000
		6.9%	7.0%	9.0%
		16.1%	16.2%	17.8%

* Assume $7.00/MWh for spinning reserves
** Assume $0.30/MWh for non-spinning reserves

2.3.4 Uncertainty

Any analysis that estimates the value of a new technology necessarily involves uncertainties. Three sources of uncertainty are addressed here: variability of customer demand, the cost of interconnection with the grid, and changing utility prices over time.

The results in the baseline analysis are meant to be representative for different customer classes in different locations. One criticism of using energy modeling programs like DOE-2.1 to estimate hourly demand is that they do not account for exceptional fluctuations due to extreme weather, consumer spikes, etc. In order to test the robustness of the method used here, all of the scenarios in the baseline were re-modeled with increased hourly variability. Variability was incorporated into the demand profiles by altering hourly demand to randomly fall within +/- 10%, 25%, and 50% of the original demand. For example, a 10% increase in variability was incorporated by multiplying demand in each hour by (0.9 + (RAND) * 0.2). These adjusted demand profiles were then input into the MCEEM, using the same assumptions as in the baseline analysis.

Table 10 shows that if consumption is more volatile than expected, the value of micro-grids may increase slightly. This is true because greater variability leads to greater demand peaks, which increases the value of the micro-grid as a peak-shaver. Trends were similar for all six cities.

Table 10. Impact of Increased Demand Variability on Baseline Results

Scenarios	Increased variability*	Savings (%)	Internal Rate of Return (%)	Electricity purchased (%)
San Diego	0% (baseline)	21.4 %	24.3 %	4.5 %
all six customer	10 %	22.7 %	25.1 %	4.9 %
mixes (averaged)	25 %	24.3 %	25.3 %	3.7 %
	50 %	25.1 %	25.1 %	4.5 %
Burlington	0% (baseline)	4.9 %	14.4 %	57.9 %
all six customer	10 %	5.6 %	15.0 %	59.9 %
mixes (averaged)	25 %	6.5 %	15.3 %	58.9 %
	50 %	7.6 %	15.1 %	52.9 %

* Variability was incorporated into the demand profiles by altering hourly demand to randomly fall within +/- 10%, 25%, and 50% of the original estimate.

The cost of interconnecting with the area electric power system depends on various factors, including the type and size of generation equipment, how the micro-grid plans to operate, and the condition of the area grid near the micro-grid. These costs can vary widely, especially if utilities are granted the freedom by regulators to set costs and "gold-plate" equipment.

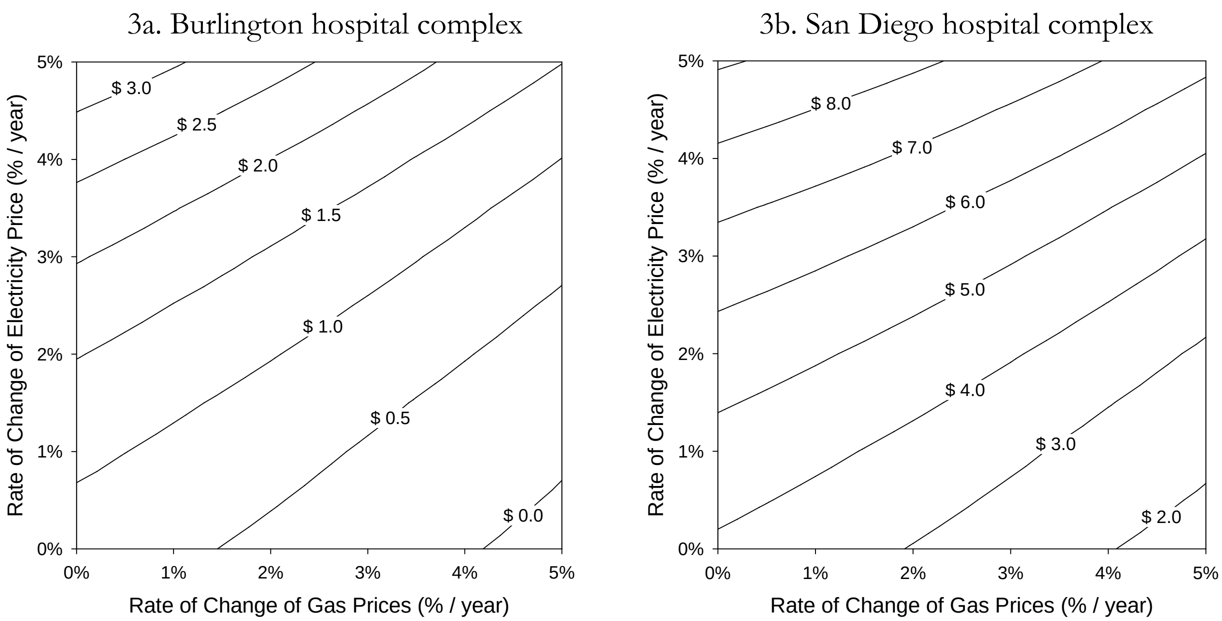
In order to estimate the cost of interconnection, data from nearly one hundred proposed interconnection projects on PJM Interconnect were compiled and analyzed (PJM 2005). Only new projects were considered, and the sample includes a variety of different sizes, locations, and generator types. In order to reduce selection bias, the sample includes both projects that were approved and withdrawn. Table 11 presents the results of the study. The average cost for approved interconnection projects was less than $25,000 per megawatt. Those projects that were withdrawn did so presumably because of cost, and most of the additional costs were due to substantial system upgrade costs that resulted from locating in a sensitive or congested area of the grid.

Micro-grid customers could avoid many of the interconnection costs, depending on how much power they export and whether the area distribution system is equipped for bi-directional flow of power. Nonetheless, barring discriminatory action by utilities or exceptional circumstances, interconnection costs for micro-grids should be relatively small – in the range of 1-3% of the installed cost of the system.

Table 11. Empirical Assessment of Interconnection Costs for Projects on the PJM Interconnect

	# of Project samples	Average project size (MW)	Average project cost ($)	Average cost ($/MW)
Small projects (< 25 megawatts)	30	11	$ 434,000	$ 41,400
Approved	16	10	$ 239,000	$ 23,200
Withdrawn	14	11	$ 657,000	$ 61,500
Large projects (> 25 megawatts)	63	407	$ 15,904,000	$ 39,100
Approved	29	350	$ 7,984,000	$ 22,800
Withdrawn	34	456	$ 22,659,000	$ 46,700

A third source of uncertainty that could considerably affect the economics of micro-grid systems is the rising price of electricity and natural gas. The price of natural gas has risen dramatically since 2000, and it is extremely difficult to predict future trends. In many areas of the U.S., especially those best suited to micro-grids, the price of gas heavily influences or even sets the price for electricity.



Figures 3 a-b. The effect of increasing gas and electricity price on micro-grid value in a) Burlington hospital complex and b) San Diego hospital complex. Contours represent millions of $'s in net present value using a 10% discount rate over 25 years.

The results presented in Figure 3 reflect MCEEM output using inputs from the baseline analysis, but adjusting gas and electricity prices over time. It is assumed that customers make micro-grid design decisions based on the prices used in the baseline analysis, and that as prices change over time customers are not able to buy or sell capacity. It is also assumed that only consumption charges change over time, not demand charges.

If electricity and gas prices both increase at the same rate over time, the lifetime value of the micro-grid actually increase because the micro-grid is operated as a combined heat-and-power application. If gas prices rise but electricity prices remain steady, micro-grids become comparatively more expensive to operate and they lose their value. In both the San Diego and Burlington hospital scenarios, the economics of a micro-grid remains steady when the price of electricity increases roughly 60% as fast as the price of natural gas (Figure 3).

US DOE EIA data from 2000-2005 indicate that average natural gas prices have increased by roughly 10-15% per year, whereas electricity prices increased by only 3-4% per year. If this trend was to continue and a cheaper fuel substitute did not emerge, the micro-grid scenarios modeled in this analysis would become much less valuable. However, it is not clear that gas prices will continue to increase at such high rates. Even more importantly, electricity prices have been kept artificially low due to price caps and lags in the approval of new tariffs. Electricity prices in some North East states have recently experienced dramatic increases, and similar increases are likely elsewhere as more price caps come off.

2.4 Sensitivity to Demand Behavior

In this section I examine the following hypotheses: 1) cold climates are better suited to micro-grids, because waste heat can be better utilized; 2) customers with relatively flat demand profiles will be able to better utilize generation assets and get better returns on a micro-grid investment; and 3) larger customers will enjoy the economies of scale (both in efficiency and capital cost) that are known to exist for distributed generation.

Here prices are set to national average values based on 2003 DOE EIA data: $8.00 per MBTU of natural gas, and $0.08 per kWh for electricity (see Table 12 for a comparison of the inputs for baseline and sensitivity analyses). Demand profiles for heat and electricity are normalized to have the same average hourly electric demand of 1,000 kW. Demand shape was maintained so the different micro-grid scenarios could be usefully compared, but any economies of scale could be isolated.

Table 12. Comparison of Inputs for the Baseline and Sensitivity Analyses

	Electricity rates**	Gas rates	Load shape	Avg. hourly demand	Discount rate
Baseline analysis	Regional 2003 utility rates	Regional 2003 gas prices	Based on DOE-2 model output	Based on DOE-2 model output	10%
Sensitivity analysis	$0.08 / kWh (2003 national average)	$8.25 / MBTU (2003 national average)	Based on DOE-2 model output	Normalized to 1 MW	5%*

* A lower discount rate was used in the sensitivity analysis because the 10% discount rate used in the baseline analysis yielded poor results for many scenarios, which could not be meaningfully compared.
** Demand charges were included in the baseline analysis. Demand charges were not used in the sensitivity analysis.

Figure 4 shows a bubble plot of NPV savings (as a percent of total NPV energy costs) for each of the 36 micro-grid scenarios. Note that climate has a considerably smaller impact on micro-grid value than customer mix. There is only a small general trend toward greater savings in colder climates.

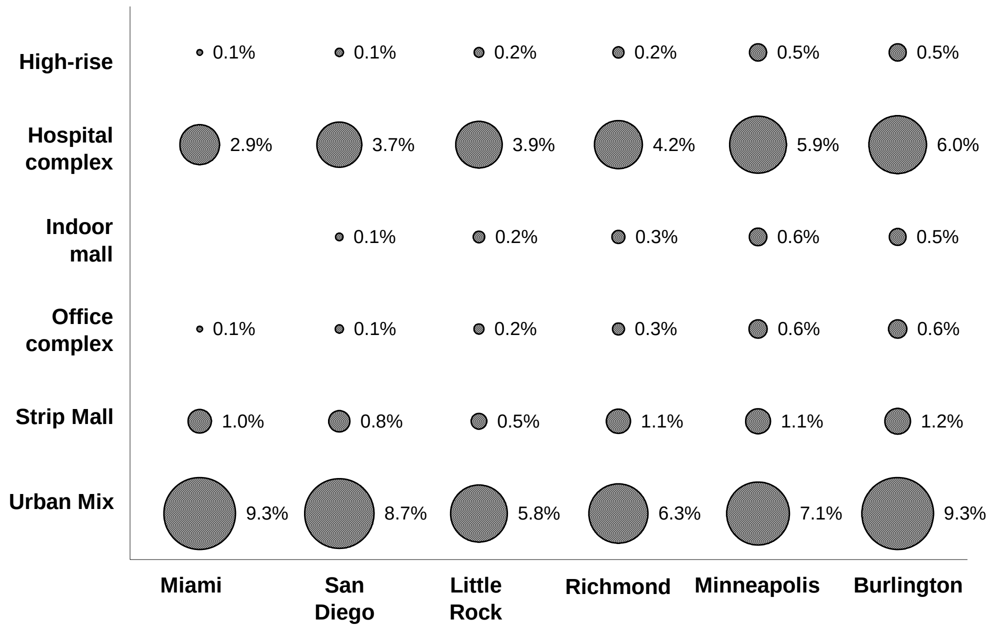
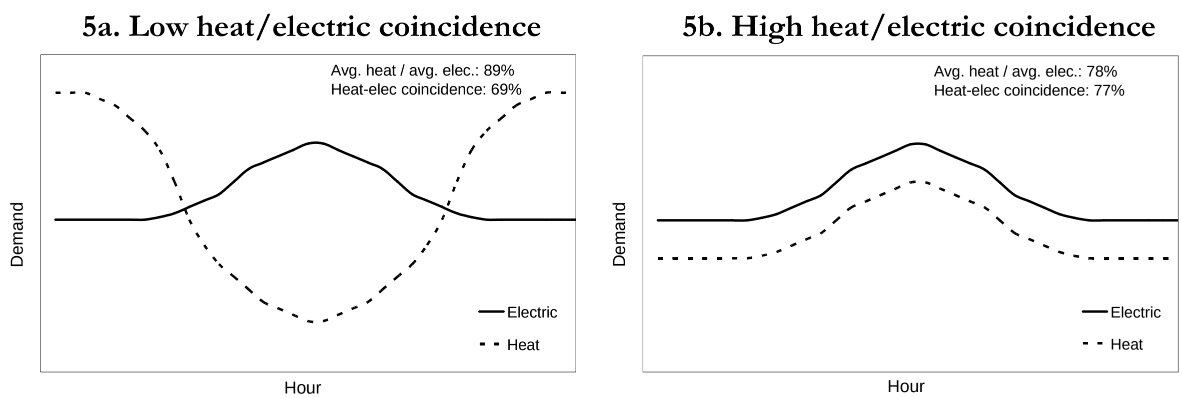


Figure 4. Results from sensitivity analysis, comparing the relative importance of climate and customer mix. Bubble area represents total lifetime energy cost savings.

In order to understand why some micro-grid applications are better investments than others, the respective shapes of both the hourly electric and heat demand must be considered. Flat demand allows better utilization of the generation assets, whereas matching heat and electricity demand allows the generation assets to operate at a higher overall efficiency. I have used two indices, load factor and heat/electric demand coincidence, to characterize demand behavior. Load factor is the ratio of average electric demand to peak electric demand. A low load factor suggests considerable demand variability, and a load factor of 1.0 indicates flat electricity demand. Heat/electric coincidence describes how well electric and heating demand match up on an hourly basis, and can be described as:

$$\text{heat/electric coincidence} = \frac{\sum_{i=1}^{8,760} \min\{kW_{thi}, kW_{ei}\}}{\sum_{i=1}^{8,760} kW_{ei}}$$

where kW_e is electricity demand and kW_{th} is heat demand in kilowatt equivalence. This is more effective than using the ratio of average heat demand to average electric demand because it more accurately captures how often the waste heat from the generators can be used to meet heat demand. This is illustrated in Figure 5. The consumer in a) has a much higher average ratio of heat to electric demand than the consumer in b) – 89% and 78%, respectively. However, the consumer in a) has a worse average heat/electric coincidence than the consumer in b) – 69% to 77%, respectively.



Figures 5a – 5b. An illustration of the importance of using correct indices to characterize demand behavior. Although the consumer in 5a has a much higher average ratio of heat to electricity demand than the consumer in 5b (89% and 78%, respectively), the consumer in 5a still has a worse avg. heat / electric coincidence than the consumer in 5b (69% to 77%, respectively).

Tables 13 and 14 show the average load factor and heat/electric coincidence for the scenarios used in this analysis, organized by city and customer mix respectively.

Table 13. Comparison of Demand Characteristics for Micro-grids in Different Locations

	Miami	San Diego	Little Rock	Richmond	Minneapolis	Burlington
Load factor	45.5 %	42.0 %	37.0 %	36.2 %	34.9 %	35.3 %
Heat/electric coincidence	24.1 %	32.7 %	39.4 %	45.4 %	58.1 %	59.8 %

Table 14. Comparison of Demand Characteristics for Different Customer Mixes

	High-rise building	Hospital complex	Indoor Mall	Office complex	Strip mall	Urban mix
Load factor	31.4 %	56.8 %	40.9 %	31.5 %	41.7 %	45.1 %
Heat/electric coincidence	17.8 %	43.3 %	13.1 %	18.8 %	23.0 %	59.0 %

Figure 6 shows that as heat/electric demand coincidence increases, the general trend is an increase in savings. A plot of load factor versus savings shows no obvious trend (Figure 7). At higher load factors the plot seems to contradict our expectations. This is because customers with low load factors (and high peaks) do actually have higher overall costs than customers with high load factors; however, this is true for conventional customers just as it is true for micro-grid customers, so load factor has a fairly small impact on the value of the micro-grid. This effect is demonstrated more clearly later in the chapter.

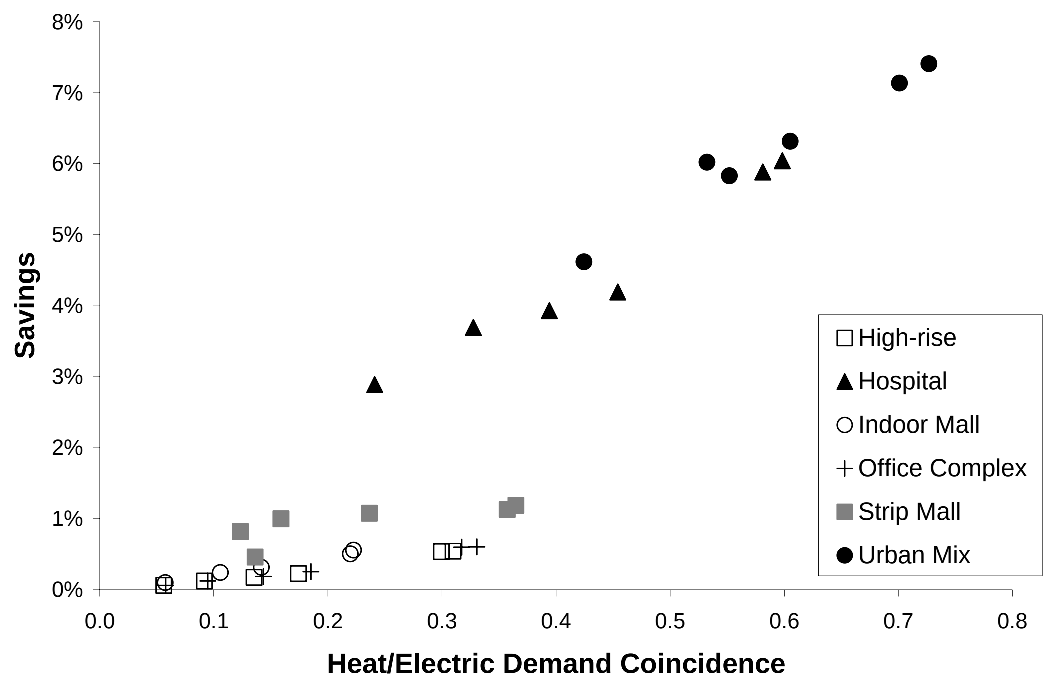


Figure 6. A plot of heat/electric demand coincidence vs. micro-grid savings for all 36 scenarios modeled.

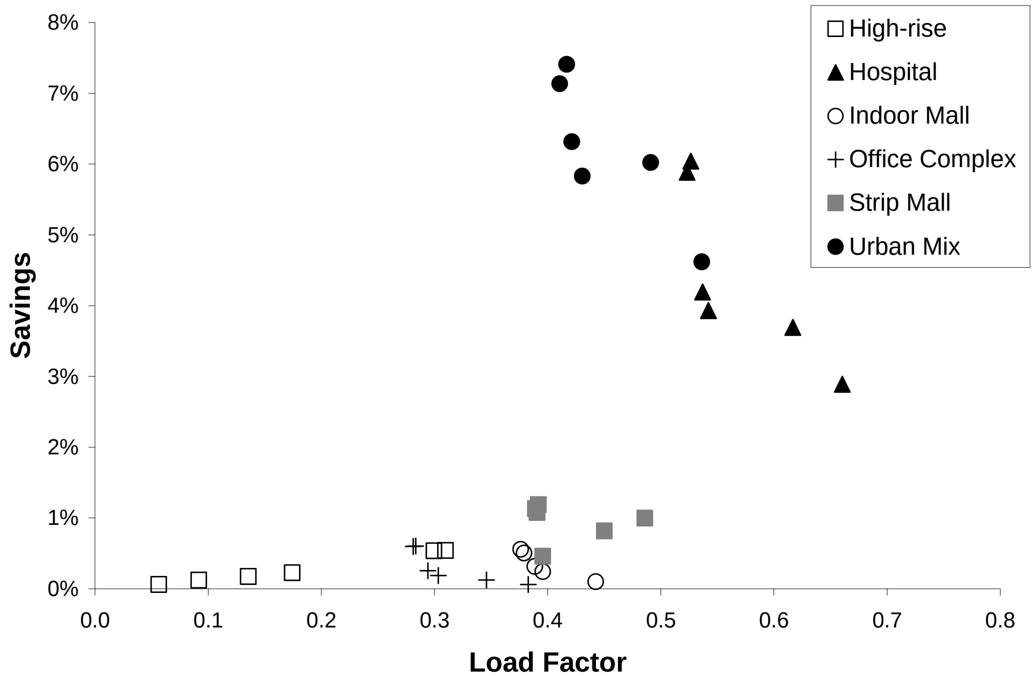


Figure 7. A plot of load factor vs. micro-grid savings for all 36 scenarios modeled.

There are two reasons why one would expect to see economies of scale in micro-grids. First, internal combustion engines have lower installed costs and higher electrical efficiencies as they increase in size (Strachan 2000). Second, commercial generators are not sold in every size, so small systems are more likely to install over-sized equipment that is economically sub-optimal. In contrast, large systems have greater flexibility in how the micro-grid is designed. There are also reasons why micro-grids may not experience economies of scale. Micro-turbines show no economy of scale either in electrical efficiency or in capital cost. Also, if reliability is a central concern, larger micro-grids may be designed with *more* generators, not necessarily *larger* generators, so the system would experience few if any economies of scale from individual generators.

Table 15. Micro-grid Value as a Function of Average Hourly System Demand (Savings in $'s, Savings in %, and Internal Rate of Return)

	Average hourly system demand			
	500 kW	1000 kW	1500 kW	2000 kW
Total average	$118,500	$265,600	$447,700	$635,300
	1.83%	2.08%	2.35%	2.51%
	8.61%	10.39%	11.57%	11.62%
High-rise average	$7,700	$31,500	$59,000	$89,000
	0.13%	0.28%	0.35%	0.39%
	5.60%	7.08%	7.90%	7.95%
Hospital complex	$256,600	$544,800	$927,600	$1,313,100
average	4.15%	4.44%	5.04%	5.36%
	14.14%	15.50%	17.59%	16.56%
Indoor mall average	$4,700	$30,900	$64,400	$104,800
	0.08%	0.29%	0.40%	0.49%
	3.52%	7.52%	10.00%	10.05%
Office complex	$9,200	$35,400	$65,000	$102,200
average	0.15%	0.30%	0.38%	0.44%
	5.79%	7.28%	7.81%	7.84%
Strip mall average	$36,800	$106,300	$193,500	$273,600
	0.65%	0.94%	1.14%	1.21%
	8.19%	10.11%	10.16%	10.62%
Urban mix average	$395,800	$844,600	$1,376,600	$1,928,800
	5.81%	6.22%	6.78%	7.13%
	14.44%	14.85%	15.98%	16.73%

Table 15 shows that larger customers require larger investments and yield much larger returns. However, in percentage terms the improvement for large systems, though positive, is relatively modest. Since investors are more likely to be interested in percent savings or rates of return than overall NPV, these results indicate that system size is a much smaller driver of cost-effectiveness than demand behavior. This investigation involved systems between 500 and 2000 kW, but there is likely a considerable diseconomy of scale for very small micro-grids (e.g. under 50 kW), at which point otherwise insignificant capital expenditures take on greater significance.

Because hourly demand profiles are fairly complicated and reflects numerous qualities of the micro-grid being modeled (e.g. location, customer mix, and size), a regression model was used to evaluate the significance of different indices used to characterize demand behavior (Table 16).

Table 16. Simple Linear Regression of Micro-grid Value (net present value % savings)			
Variable	Parameter estimate	Standard error	P-value
Intercept	-0.0279	0.00258	< 0.0001
Average_demand	5.08×10^{-06}	6.848×10^{-07}	< 0.0001
Coincidence	0.138	0.00293	< 0.0001
Load_factor	0.0349	0.00549	< 0.0001
Climate_zone	-0.00140	1.08×10^{-04}	< 0.0001

N = 144; Adjusted R^2 = 0.969

A 1% increase in coincidence or in load factor results in an increase in NPV percent savings of 0.138 and 0.0349, respectively. The average demand variable is measured in kW, so an increase in average demand of 1000 kW results in an increase in NPV percent savings of 0.0051. The climate zone variable is measured in EPA climate zones from 1 (very hot) to 18 (very cold). A change of one climate zone would be expected to yield a change in NPV percent savings of 0.140. This is a much smaller impact than expected, and since most of the U.S. is within 10 climate zones it means that the difference between building a micro-grid in Dallas, TX (climate zone 5) and Minneapolis, MN (climate zone 15) is only a savings of an additional 1.5% of total energy costs.

The value of a micro-grid is by far most sensitive to the heat/electric demand coincidence, followed by the load factor and climate zone, and finally average demand. It is important to note that climate zone is positively correlated with heat/electric coincidence (0.51) and negatively correlated with load factor (-0.37). This explains in part why climate zone alone has a fairly weak influence on micro-grid value: colder climates can make better use of waste heat, but increased seasonal variation leads to poor resource utilization.

2.5 Value of Research and Development

The US DOE initiated the Advanced Integrated Micro-turbine Systems Program (AIMS) in 2000, and the Advanced Reciprocating Engine Systems Project (ARES) began a year later. These two programs continue in the US DOE Office of Electricity Delivery and Energy Reliability. The stated goals for both programs include: higher efficiency, lower emissions, lower capital cost, improved durability and reliability, and fuel flexibility.

The specific, quantified program goals for both ARES and AIMS are ambitious (Table 17). DOE's expectation is that they will be achieved through developments such as: new designs for gas compression, combustion, and heat recovery; development of advanced materials; integration of sensors and controls; standardization of plug-and-play grid interconnection; and low-cost manufacturing methods. (AIMS 2000; ARES 2001)

Table 17. Selected DOE Distributed Energy Program Goals

	Electrical efficiency	Operation and maintenance cost ($/kWh)	Installed cost ($/kW)
Advanced Reciprocating Engine Systems program goals	50%	$0.010	$400-$450 /kW
Commercially-available engines	30-40%	$0.011-$0.015	$750-$1,500
Advanced Integrated Micro-turbine Systems program goals	40%	n/a	$500 / kW
Commercially-available micro-turbines	30%	$0.0075 - $0.010	$1300-$1700

I asked: 1) can technological improvements have a substantive impact on the economics of micro-grids? 2) which, if any, improvements will have the most benefit? and 3) do the benefits depend on the micro-grid application? Scenarios were modeled exactly as in the baseline analysis, except for changes that reflect the improvements being analyzed. The five improvements were: higher electrical efficiency; lower capital costs; lower operation and maintenance (O&M) costs; all three

ARES/AIMS goals (the combination of efficiency, capital cost, and O&M improvements); and improved peak availability. Although improved availability is mentioned among the ARES and AIMS program goals, the specific goal is not quantified. In the baseline analysis, DG generators operate with 99% availability during peak hours (engines and micro-turbines operate at 93% and 90% availability overall, respectively); in the upgraded scenarios, generators are modeled with 100% peak period availability. This upgrade represents better inspection and maintenance rather than technology improvements.

A subset of the baseline scenarios was modeled. The trends in the results for the high-rise scenarios (Table 18) are representative of other customer mixes.

Each of the upgrades has a positive impact in at least one location. When all of ARES/AIMS upgrades are modeled, customers are predicted to install larger systems that yield much better returns. Notably, the value of achieving the ARES/AIMS goals is super-additive, so improving efficiency, lowering capital costs, and reducing O&M costs have a reinforcing effect, and the DOE programs are right to pursue these improvements together.

The O&M upgrade shows the smallest value, because the improvement only applies to engines and reflects only a slight change from current specifications.

Table 18. Impact of Technology Upgrades on Micro-grid Value, High-rise Scenarios

City	Upgrade	Savings ($)	Savings (%)	Internal rate of return	Installed capacity	% Electricity bought
Miami, FL	None	$ 0	-	-	0	100%
	Low Capital Cost	$ 25,800	0.3%	14.1%	150	99%
	ARES/AIMS goals	$ 46,000	0.6%	14.4%	250	98%
	High-efficiency, Low O&M, and High Availability upgrades had no effect					
San Diego, CA	None	$ 2,697,000	21.9%	22.3%	2,700	3%
	High-efficiency	$ 4,046,100	32.9%	29.0%	2,600	0.6%
	Low Capital Cost	$ 3,571,900	29.0%	33.4%	2,600	1%
	Low O&M	$ 2,807,300	22.8%	23.4%	2,600	5%
	ARES/AIMS goals	$ 5,182,400	42.4%	43.3%	2,600	0.5%
	High Availability	$ 3,948,600	32.1%	32.1%	2,400	5%
Little Rock, AR	None	$ 0	-	-	0	100%
	Low Capital Cost	$ 24,200	0.6%	13.8%	150	99%
	ARES/AIMS goals	$ 44,400	1.1%	13.5%	300	99%
	High-efficiency, Low O&M, and High Availability upgrades had no effect					
Richmond, VA	None	$ 0	-	-	0	100%
	Low Capital Cost	$ 12,700	0.3%	12.1%	150	99%
	ARES/AIMS goals	$ 17,500	0.4%	12.8%	150	99%
	High-efficiency, Low O&M, and High Availability upgrades had no effect					
Minneapolis, MN	None	$ 4,700	0.1%	10.9%	50	98%
	High-efficiency	$ 14,100	0.2%	11.3%	100	94%
	Low Capital Cost	$ 294,500	4.8%	21.4%	600	82%
	Low O&M	$ 4,700	0.1%	10.9%	50	98%
	ARES/AIMS goals	$ 418,700	6.8%	21.7%	800	71%
	High Availability	$ 6,400	0.1%	10.4%	100	96%
Burlington, VT	None	$ 340,200	4.1%	12.8%	1,550	59%
	High-efficiency	$ 1,010,700	12.0%	16.4%	2,000	20%
	Low Capital Cost	$ 904,800	10.8%	18.2%	2,000	44%
	Low O&M	$ 435,300	5.2%	13.8%	1,500	59%
	ARES/AIMS goals	$1,841,500	21.9%	23.9%	2,350	18%
	High Availability	$ 802,300	9.6%	16.9%	1,750	44%

* Net present energy costs saved by installing a micro-grid, using a 10% discount rate and a project lifetime of 25 years.
** Percentage of total energy lifetime costs (in net present value) saved by installing a micro-grid.

Capital cost reductions will not only improve the economics of micro-grids, but also promote the installation of larger systems. This may be important in areas where utility transmission and distribution is congested, because larger micro-grid systems can more easily provide ancillary services during disturbances and peak-shaving during periods of high demand. This is demonstrated by the fact that the systems in Little Rock, Miami, and Richmond yield IRRs well above 10%, but still only generate 1-2% of their own power. In these cases, the DERs are operated less as a micro-grid and more as a peak-shaving, back-up system.

The electrical efficiency upgrade has the greatest impact in areas where micro-grids are already fairly cost-effective. For example, in both the Burlington and San Diego high-rise, increased electrical efficiency results in higher NPV percent savings of 8% and 11%, respectively. In contrast, the efficiency upgrade has almost no impact in Minneapolis, Little Rock, Miami, and Richmond.

2.6. Micro-grids vs. Traditional Distributed Generation Applications

In order to compare a micro-grid with conventional DG applications (those that serve only a single customer), each customer mix was modeled using the MCEEM. In the case of conventional DER systems, each individual building within a micro-grid was modeled separately and treated as an independent decision-maker, unable to exchange power or heat with its neighbors. All of the baseline assumptions were maintained, but only the multi-building scenarios were modeled.

Table 19. Comparison of Micro-grids to Traditional DG Applications in San Diego

Customer mix		Savings* ($)	Savings** (%)	Internal rate of return	% of electricity purchased
Hospital complex	Micro-grid	$3,453,400	24%	32%	4%
	Traditional DG	$2,380,800	16%	22%	5%
	Added Value	**$1,072,700**	**8%**	**10%**	**-1%**
Office complex	Micro-grid	$5,019,400	26%	26%	4%
	Traditional DG	$2,234,300	11%	15%	8%
	Added Value	**$2,785,000**	**15%**	**11%**	**-4%**
Strip mall	Micro-grid	$1,626,500	19%	22%	8%
	Traditional DG	$812,700	9%	16%	12%
	Added Value	**$813,800**	**10%**	**6%**	**-4%**
Urban mix	Micro-grid	$478,100	18%	21%	6%
	Traditional DG	$364,100	13%	17%	10%
	Added Value	**$114,000**	**5%**	**4%**	**-4%**

* Net present energy costs saved by installing a micro-grid, using a 10% discount rate and a project lifetime of 25 years.
** Percentage of total energy lifetime costs (in net present value) saved by installing a micro-grid.

Table 19 presents the results for different sets of customers in San Diego. Traditional DER applications did perform well, generally showing favorable returns. However, when customers are organized into a micro-grid, the overall economic picture improves. On average, system NPV savings increase from an average of 12% to 22% (on average, $1.2 million); internal rates of return increase from 17.5% to 25.25%, and average purchases from the grid fall from 8.75% to 5.5%.

The value of aggregating customers onto a micro-grid will depend heavily on the mix of customers, system design, and local gas and electric rates. Likewise, various policy and administrative barriers may prevent clusters of consumers from coordinating to install and operate a micro-grid system. However, this analysis presents clear evidence that the micro-grid design produces substantial benefits and deserves consideration from policy-makers, manufacturers, the R&D community, and customers.

2.7 Conclusions

In the US, considerable attention has been devoted to conventional distributed energy resources (DERs) over the past decade. The US DOE estimated that there were roughly 53 gigawatts of distributed generation in the US in 1998, which reflects an interest by customers seeking the reliability benefits of DERs. Regulatory progress has been made to allow and encourage the adoption and development of conventional DER applications. This chapter has explored the circumstances under which interconnected micro-grids with combined heat and power can be cost-effective, and how the value of a micro-grid compares with that of conventional DER applications. The results suggest that policy-makers should begin to address some of the regulatory obstacles that are preventing micro-grid development, particularly while there is regulatory attention being given to conventional DER applications. The legal standing of micro-grids and the terms under which they can be installed, interconnected, and operated should be clarified so that regulatory risk and legal uncertainties do not continue to swamp the economics of micro-grid projects that would otherwise be profitable.

This chapter has shown that micro-grids can provide economic value to some customers, with the potential to save as much as 20-25% of the total system energy costs over a project lifetime. Micro-grids will be most attractive in areas with relatively high electricity prices and/or low natural gas prices. Micro-grid cost-effectiveness is not contingent on a very large spark spread (electricity / natural gas price differential); for example, model results show a positive value for micro-grids in Minneapolis, even though Minnesota ranks 39th in the US in spark spread.

In cases where customers have a higher value for electric reliability, or corresponding willingness to pay for back-up capacity, the economics improves – in some cases making micro-grids cost-effective where they would otherwise not be. If utility electricity and gas prices increase at the same rate over time, micro-grid value actually increases. In the more cost-effective cases, if electricity prices increase at 60% of the pace of natural gas prices, micro-grid value stays steady over time. Recent dramatic increases in natural gas prices may reduce the viability of micro-grids, unless electricity prices also rise due to these higher fuel prices and the removal of price caps in certain regions.

Results from sensitivity analyses reveal that the choice of micro-grid customer mix has a much greater impact on system economics than climate. A good mix of customers will result in higher coincident heat and electricity demand, which enables better use of waste heat and increased overall system efficiency and cost savings. The effect of climate is less significant than expected, and results suggest that although micro-grids in colder climates are able to make better use of waste heat, increased demand variation in cold climates leads to poor resource utilization.

Economies of scale were shown to be fairly modest in the range considered here, although the economic performance of micro-grids is superior to that of traditional distributed generation applications. In areas where conventional distributed generation applications are already cost-effective, such as San Diego, micro-grids can provide considerable value to customers. By grouping customers and aggregating demand, customers are able to install larger systems and operate them more frequently and efficiently.

If targets for technology improvement within the Department of Energy research and development programs are realized, the economics of micro-grid systems improves dramatically, increasing rates of return by 10-20%. Reductions in capital cost were determined to be the most important program goal, followed by increased system efficiency.

A comparison of conventional DER applications and micro-grids shows that, for the same set of customers, aggregating customers and generation resources into a micro-grid can provide substantial economic value to the customer.

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Chapter 3. The Regulatory Environment for Interconnected Electric Power Micro-grids: Insights from State Regulatory Officials

3.1 Introduction

Distributed energy resources (DERs)[9] have become the focus of considerable inquiry in the U.S. and around the world. There is a growing body of research that indicates that DERs are not only a reasonable investment for certain types of customers (particularly those that value high reliability and flexibility), but could also provide net benefits to the area's legacy utility and its customers while improving energy use efficiency and environmental quality (IEA 2002; Bailey et al. 2003; Pepermans et al. 2005; Stovall Hadley et al. 2005)

Capturing the full range of benefits that DERs can provide depends heavily on their design and implementation. Generally, the economic and environmental quality benefits associated with DERs require the use of combined-heat-and-power (CHP) or combined-cooling-and-power (CCP) applications that capture "waste heat" from on-site generators to provide space and water heating (Meyers and Hu 2001; Strachan and Dowlatabadi 2002; Gulli 2004) or cooling using absorption chillers or dessicants (Bailey, et al. 2002; Wang and Oliveira 2005). The provision of high reliability may depend on the integration of DERs with energy management systems and complementary technologies such as uninterruptible power supplies, automated controls, etc. (Willis and Scott 2000). The benefits to utilities, including ancillary services and obviated T&D improvements, depend on the location of the DERs on the system and require advanced controls and integration with the utility system (Lasseter et al. 2002).

[9] Distributed energy resources can include generation, energy storage, and demand management. Distributed generation (DG) refers only to generation resources, such as engines and micro-turbines.

The cost-effectiveness of DERs can also depend on the size and type of installation, due to economies of scale. The economies of scale for DERs result from two phenomena: 1) reduced installed equipment costs and increased operating efficiency of large generating equipment, and 2) improved asset utilization from more flat, predictable demand profiles. These phenomena are supported by theory (Willis and Scott 2000) and empirical study (Strachan 2000).

In order to best capture the full potential of DERs, a new system architecture known as the micro-grid has been developed.[10] A micro-grid uses distributed generation with cogeneration to provide electricity and heat to multiple customers connected on a local network. The micro-grid is generally interconnected with the local utility through a single point of common coupling, operates in parallel with the area grid, and is capable of automatically and instantaneously responding to stimuli from the area utility to either disconnect or provide support during disturbances. Generation and demand on a micro-grid are integrated in a manner that allows customers to shed or otherwise manage loads in such a way as to optimize the performance, cost, and reliability of the micro-grid system during grid disturbances (Kueck, Staunton et al. 2003).

Micro-grids can interconnect at high voltages and participate in regional energy and ancillary service markets, but it is more likely that smaller systems will interconnect at distribution voltages and buy and sell power through the distribution utility. It is also possible for micro-grids to operate independently from the central distribution system. In remote areas of the world where there may not be a central grid or interconnection may be cost-prohibitive, this application makes considerable sense (for an example, see Mendez et al. 2003). However, this design does present technical and

[10] The micro-grid concept is more thoroughly explored in publications by the Consortium for Electric Reliability Technology Solutions (CERTS), available on-line at http://certs.lbl.gov/CERTS_P_DER.html .

economic challenges if customers demand reliable power (Tanrioven 2005), and from a regulatory standpoint this design is less of a concern than interconnected systems.

While the micro-grid architecture is designed to build on and maximize the value of DERs, it is sufficiently different from traditional DER applications that the regulatory environment is still clouded in considerable uncertainty. There has been progress by state governments, independent system operators, and even federal regulators to facilitate the development and adoption of traditional DER applications, but most regulatory officials are still unfamiliar with the micro-grid concept and uncertain about how policy developments relate to this new architecture.

This new technology and its market and regulatory barriers have been the focus of considerable international research. The first international micro-grid symposium was held in 2005[11], and attracted over 30 organizations from 11 countries to discuss technical and market issues related to micro-grids. The European Commission has funded a micro-grid research project as part of its Cluster Integration program, which organized over 100 partners and nearly $40 million to investigate issues related to energy-efficiency and DER technologies. The micro-grid project includes partners from France, Germany, Greece, the Netherlands, Portugal, Spain, and the UK, and has resulted in nearly 50 presentations and publications, and numerous test facilities.[12] In Japan, several demonstration projects have been initiated by electric utilities and the government's New Energy and Industrial Technology Development Organization (NEDO).

[11] The 2005 Symposium on Micro-grids was held 17 June 2005 in Berkeley, CA. The Symposium was organized by CERTS. For more information, visit http://der.lbl.gov/CERTSmicrogrids.html.
[12] Visit http://microgrids.power.ece.ntua.gr/micro/default.php for more information and access to publications.

Investigative work funded by the European Commission (Pudjianto and Strbac 2005; ELEP 2005) reveals similarities between the US and EU member state policies for DERs: there has been significant regulatory progress in the EU on technical interconnection requirements and administrative interconnection procedures, but fairly little work to address other barriers. Very little regulatory attention has been given to micro-grids in particular, but the legal distinctions between micro-grids and conventional DERs in Europe seem to be less significant than in the US. The focus throughout the remainder of this study will be on US regulatory policies for micro-grids, but comparisons to the international perspective will be made where possible and/or valuable.

This chapter builds upon previous work by Morgan and Zerriffi (2002) to explore the legality of micro-grids. Morgan and Zerriffi concluded (on the basis of a survey of 8 then-current and former state regulators associated with the EPRI Advisory Board) that regulatory barriers exist that can inhibit the installation of micro-grids, and that it is generally not legal to install or operate an independent electric power micro-grid.

Efforts to clarify and resolve some of the regulatory barriers (King and Morgan 2003) revealed that the regulatory environment for micro-grids in the US is more nuanced and complex than previously thought. Regulators across the country have different notions of what a micro-grid is and how it might operate, and their opinions may depend on how the micro-grid concept is framed. When framed as a small independent power producer, a micro-grid may yield a different reaction than when it is framed as a large distributed generator, or placed in the context of energy services or demand management. Section 2 outlines various applications of the micro-grid concept and their differences. Providing this taxonomy is necessary in order to remove the preconceptions and misunderstandings that exist about micro-grids, especially in the regulatory community.

In Fall 2004, a more extensive survey of state regulators was conducted to better understand the regulatory environment for micro-grids. Regulatory officials, including Commissioners, Directors and General Counsels, from every state were contacted (almost 250 individuals) and at least one response was received from 27 different states (see Table B1 in Appendix B). The survey sought to more fully explore the nature of the regulatory uncertainties that exist, and provide respondents with a better context within which to think about micro-grids. The survey method and resulting insights are discussed in Section 3.3. Section 3.4 provides a summary of recommendations for regulatory changes.

3.2 Micro-grid Ownership Models

In order to keep the task manageable, the survey explicitly defined micro-grids as a single concept. However, many regulators observed either explicitly or implicitly that all micro-grid applications are not the same in the eyes of the law. Moreover, the differences among micro-grids that matter most to regulators are not in the technical details of the micro-grid installation and operation, but rather in the micro-grid ownership and business practices – that is, in how they make money.

When asking questions about the regulatory environment for micro-grids, regulators generally have a single, predominant conceptual ownership or business model in mind as they answer. When this model is challenged and new models are explored, nuances appear and the regulatory environment becomes even more muddled – but possibly more open.

I propose the existence of five different models that can be used to categorize micro-grids by their ownership and business practices. The use of such models should help reduce confusion and facilitate policy discussion and development. The five models are:

1) *Utility model* – the distribution utility owns and manages the micro-grid to reduce customer costs and provide special services (e.g. high power quality and reliability) to customers on the system.
2) *Landlord model* – a single landlord installs a micro-grid on-site and provides power and/or heat to tenants under a contractual lease agreement.
3) *Co-op model* – multiple individuals or firms cooperatively own and manage a micro-grid to serve their own electric and/or heating needs. Customers voluntarily join the micro-grid and are served under contract.
4) *Customer-generator model* – a single individual or firm owns and manages the system, serving the electric and/or heating needs of itself and its neighbors. Neighbors voluntarily join the micro-grid and are served under contract.
5) *District heating model* – an independent firm owns and manages the micro-grid and sells power and heat to multiple customers. Customers voluntarily join the micro-grid and are served under contract.

Depending on the state in which a micro-grid is located, these models may be considered very different by regulators. Generally, the Utility and Landlord models are viewed most favorably by regulators and the District Heating model is viewed least favorably. These opinions are often supported by regulatory law, and they reflect the risks (real and perceived) that different types of systems pose to legacy utilities and their customers.

Another distinction that can be made among different micro-grids is the way in which they interconnect with the local utility. Micro-grid interconnection can be classified as one of three types: islanded; interconnected at distribution voltages; and interconnected at transmission voltages. In this context, an islanded micro-grid refers to the creation of a system that is never interconnected with the area grid. A permanently islanded micro-grid would be granted much greater flexibility by state regulators and might not even be subject to regulation in some states. This case is fairly uninteresting and is not discussed further.

The distinction between distribution and transmission voltage interconnection does warrant some discussion. From a regulatory standpoint, interconnection at high voltages does not necessarily result in different rules; however, it does generally indicate participation in the wholesale market. Participation in wholesale markets would result in new regulatory components, particularly those introduced by system operators (e.g. PJM, MISO) and federal regulators (e.g. FERC). The rules and regulations imposed by system operators and federal regulators are not within the scope of this investigation, but both FERC and many ISOs have taken steps to develop and adopt standardized interconnection rules and procedures.[13]

The remainder of this chapter focuses on the regulatory environment for micro-grids that are interconnected with the local distribution utility at distribution voltages. This focus reflects the available expertise of the regulatory officials who participated, and the expectation that most interconnected micro-grids will have neither the interest nor the technical capabilities to participate in the wholesale market.

[13] Representatives at FERC and system operators were not contacted for this survey. However, many state regulators did mention federal and regional rules when discussing the legality of micro-grids at transmission voltages.

3.3 The Regulatory Environment for Micro-grids

3.3.1 Survey methodology

In September and October 2004, nearly 250 members or senior staff representing every state Public Utilities Commission or Public Service Board were contacted by e-mail or phone requesting that they participate in an on-line survey. Follow-up contacts were made in states where no one had yet agreed to participate. The survey was reviewed and approved by Carnegie Mellon University's Institutional Review Board prior to the release of the survey. The survey period lasted nearly 5 months, and the result was 33 responses from 26 different states plus the District of Columbia.

The survey consisted of 4 informational questions and 20 questions related to the regulatory environment for micro-grids. Most of these questions were open-ended, and respondents were asked to answer questions as they relate to their home state, and base their answers on specific regulatory rules or laws when possible. Respondents were given some background about the micro-grid concept and some context for the survey. Respondents were asked to consider micro-grids that are between 500 kW and 20 MW in size, utilize various generation sources (including natural gas engines and micro-turbines), and operate as a "collection of interconnected electric power sources that provide power and heat to multiple customers near the point of consumption."

Survey questions fell into three categories: the legality of micro-grids; interactions between micro-grids and utilities; and regulatory oversight of micro-grids and micro-grid firms. Questions about the legality of micro-grids focused on the relevance of size, ownership and management, and interconnection voltage levels. Questions about customer-utility interactions focused on service territories, interconnection procedures, technical interconnection requirements, and tariffs. Questions about regulatory oversight focused on whether and how the State should oversee micro-grid operation, micro-grid interactions with customers (e.g. billing, dispute resolution), and provision of information to the State. The complete survey, along with a list of respondents and their responses are available in Appendix B.

3.3.2 The legality of micro-grids

Whether a firm or group of customers has the legal right to build and operate a micro-grid depends primarily on one issue: whether a micro-grid is defined or perceived to be a public utility. If a micro-grid is interpreted as a public utility it stands little chance of being permitted to operate, especially within the service territory of another public utility.[14] Further, the administrative and financial burden of being designated a public utility is likely to be prohibitive for micro-grid owners.

If a micro-grid can avoid *public utility* status, there are areas of the country where it has the right to operate. Respondents from seventeen of the twenty-seven participating states gave the opinion that a micro-grid owner definitely or probably has the right to install and operate. Respondents from five states indicated that micro-grids are illegal, and this opinion usually followed the assertion that any micro-grid would necessarily be considered a public utility. Respondents from five states indicated that the legality is unclear. A state-by-state breakdown of these results is provided in Table 20.

Table 20. Responses to Questions About Micro-grid Legality

If a group of customers wants to build a micro-grid that is interconnected with the area grid at *distribution voltages*, are there any circumstances under which it is legal?		
Yes / probably	No / probably not	Uncertain or unclear
17 states	5 states	5 states
AK, DE, FL, GA, IA, IL, MI, MN, MO, NY, OR, PA, TX, UT, VT, WI, WY	IN, LA, MA, SC, WA	AL, DC, NJ, OH, SD

[14] In some states there are exceptions for cooperative or municipal utilities. For example, in MN a municipal utility can exist within another utility service territory, but the original serving utility must be compensated.

In states where micro-grid owners might have a legal right to install and operate, there are still various limitations on the structure of the micro-grid and the nature of its business. Three stipulations were most commonly cited for systems that want to operate with non-utility status:

1) The micro-grid owner(s)/operator(s) must be the primary consumer(s) of the electricity.
2) Micro-grid customers must be on or contiguous to the site where power is generated.[15]
3) A micro-grid may serve only a limited number of customers.[16]

At least one of these stipulations is applicable in every state, although some states have more restrictive language than others. In almost every case these stipulations allow a micro-grid to be owned and operated under the Utility model or Landlord model. The stipulations become more important and more restrictive for micro-grids developed in the Co-op model, the Customer-generator model, and the District Heating model because there are multiple customers located on separate parcels of land. Micro-grids developed in the District Heating model are most likely to be judged a public utility because the owner/operator may consume little or none of the power on the system.[17]

According to respondents, neither the interconnection voltage nor the size (generation capacity) is considered to be an important determinant of the legal rights of a micro-grid to operate. Many respondents recognized that a micro-grid could face additional rules or regulations from FERC or regional system operators (PJM, MISO, etc.) if it interconnected at transmission voltages. Two

[15] The definition of "contiguous" varies. For example, in GA and NJ a group of customers are not considered contiguous if they are separated by an easement, public thoroughfare (road, etc), or utility-owned right-of-way.
[16] For example, IA sets an upper limit of 5 customers, AK has a limit of 10, and MN has a limit of 25.
[17] This opinion was given by respondents in AL, IA, IL, NJ, NY, OH, OR, SD, TX, VT, WA, and WY.

respondents also judged that interconnection at transmission voltages could increase the likelihood that a micro-grid was considered a public utility, but it was unclear.

Similar issues exist outside of the US. For example, electricity suppliers in both the UK and Greece are required to have state-granted supply licenses. Exemptions exist in the UK for generators that meet only their own demand or supply less than 2.5 MW directly to other customers. In Greece, exemptions exist for very small systems (less than 20 kW) and research facilities. In the Netherlands, small networks like micro-grids can be built and operated, subject to certain technical and energy-efficiency conditions, and the stipulation that no more than 500 residential customers are served (Pudjianto et al., 2005b).[18]

3.3.3 Uncertainty as a barrier to micro-grid development

Despite the fact that micro-grids might have a legal right to exist in many states, there are still many barriers to micro-grid development that stem from regulatory ambiguity. A prospective micro-grid faces considerable uncertainty with regard to where and how it can be built and operated under the existing regulatory environment. This uncertainty poses a large financial risk for entrepreneurs; such risks can swamp an investment decision and lead to chronic underinvestment for even highly cost-effective applications.

There is consensus among regulatory officials that the current regulatory environment for micro-grids is at best murky. The survey of regulatory officials explored three sources of uncertainty for micro-grid projects: the existence and relevance of utility service territories; utility services and tariffs; and interconnection procedures and technical requirements. The paragraphs that follow

[18] These small networks must be granted an exemption, as per Article 15 of the Electricity Act of 1998.

explore the nature of these uncertainties. In Section 6, I discuss steps that regulatory authorities can take to clarify the regulatory status for electric power micro-grids.

Service territories

Distribution utilities have traditionally been granted monopoly power to provide service to customers within pre-defined service territories. These territories were created to sustain what was considered a natural monopoly designed to avoid redundant wires crossing a city or town. Service territories reduced the utility's financial risks by guaranteeing a customer base through which capital investments could be recovered, and gave customers assurance that they would receive electric service.

Service territories exist in some form in every state that participated in this study. Some states have pockets where multiple distribution companies can compete, but this is rare. The existence of unique service territories was the primary reason given for why micro-grids might not be legal. Even in states where micro-grids have a legal right to operate, utilities are likely to oppose them and use service territories as a justification for blocking development. Such opposition is manifested in legal challenges, which can take years to settle and yield considerable costs and risks to those proposing to install a system.

One example is the 1997 proposal by Pennsylvania Enterprises, Inc. (PEI) to build a micro-grid, or 'power park' at an industrial park site in Archbald, PA. The local utility, PPL, argued before the PA PUC that the PEI Power Park constituted a public utility and should not be allowed to provide services to customers in the PPL service territory. In September 1998 the PUC issued a declaratory order that PEI Power Park was not a public utility, and could proceed.[19] Ground was broken on the project in November 1998 and PEI already had customer commitments. However, PPL continued to oppose the project. Under continuing legal threats by PPL in civil court, and the fear of ruining their relationship with the local utility (from which PEI had to purchase standby and supplemental power), PEI abandoned its plans to directly supply electricity to its customers.[20]

In the UK, the distribution systems are operated by Distribution Network Operators (DNOs), which are granted monopoly service territories by the national regulatory agency. Unless DNO's invest in micro-grids themselves, considerable growth is considered unlikely (Pudjianto et al., 2005b). In the Netherlands, micro-grids can exist with the service territories of so-called "network operators", but market competition rules actually make it more difficult for a utility to own a micro-grid.

Utility tariffs

In recent years many public utilities have developed tariff arrangements to meet the needs of customer-generators that employ traditional distributed generation. In some states these tariffs are required by the regulatory authority. In states where it is not mandatory, there are utilities that have developed them voluntarily.

State law may require utilities to develop tariffs but often it does not dictate how (e.g. rates, applications) or to whom tariffs should apply. In cases such as this, or in states where utilities voluntarily develop customer-generator tariffs, the utilities have wide latitude over the tariff design

[19] A petition for a declaratory order was filed by PG Energy, Inc., then-owners of PEI Power Corporation, at docket 00981405. The Pennsylvania PUC issued its order on September 3, 1998.
[20] This account is based on phone discussions with employees of PEI Power Corporation in June 2004, and news releases published between 1996 and 1999 on the PRNewsWire.

and its applicability. The resulting tariff structures give the utility maximum flexibility, enabling them to refuse service to customers on fairly loose grounds. Such flexibility undermines the general rights of DER customers by making the applicability relatively arbitrary, and creates an uncertain regulatory environment for prospective DER customers.

The uncertainty discussed above is compounded by the question of whether customer-generator tariff arrangements are even applicable to micro-grids. According to survey responses, most states (25 of the 27 participating states) have tariff arrangements (mandatory or voluntary) for customer-generators. Among regulators in these states, less than half gave the opinion that the tariff arrangements would definitely or probably apply to micro-grids. In cases where utilities have great flexibility in the application of these tariffs, the utilities may be the ultimate judge of whether such customer-generator tariffs apply to micro-grids. In cases like this, a utility is unlikely to grant favorable tariffs to micro-grids that directly compete with the utility for customers.

Interconnection procedures and technical requirements

An economically viable micro-grid must be interconnected with the area electric grid and allowed to purchase and possibly sell electricity. Utilities have been reluctant to let distributed energy resources interconnect with the grid, citing safety and system stability concerns. While these concerns are sometimes justified, system operators and regulatory authorities have found ways to alleviate these concerns by formalizing the interconnection process in a manner that fairly places responsibilities and burdens of proof on both customer-generators and the utility.

When designed correctly, these procedures lay out the timeline and responsibilities for both parties, as well as contingencies if either party fails to meet its obligations. They provide customer-generators with the assurance that if they meet certain pre-defined standards they will be able to interconnect within a reasonable amount of time. They provide utilities with the assurance that customer-generators will not have an adverse impact on their system or their customers.

Recent national and regional developments in this area include IEEE P1547, FERC's proposed Standardization of Small Generator Interconnection Agreements and Procedures, and PJM's ongoing work on small generation interconnection standards. On the state level, the National Association of Regulatory Utility Commissioners (NARUC) published model interconnection procedures in October 2003, and survey results suggest that most states have interconnection procedures and technical requirements in some form that apply to distributed energy resources (see Table 21). The Texas Distributed Generation Interconnection Manual is a particularly good model for clear, standardized interconnection procedures.

Table 21. Applicability of State DER Interconnection Rules to Micro-grids*
(total # of states, out of 27 total respondents)

	Have applicable rules for traditional DERs?	Would these rules that apply to DERs also apply to micro-grids?				
		Yes	Probably	Probably Not	No	Unclear / Respondent Unsure
Tariff Arrangements	25	7	4	7	1	6
Interconnection Procedures	24	9	4	3	3	5
Technical Interconnection Requirements	19	7	4	4	0	4

* A state-by-state breakdown of these results is provided in Appendix B.

Despite progress in most states on the technical and procedural requirements for traditional distributed energy resources, it is not clear that this translates into regulatory clarity for micro-grids.

Among 24 states that reportedly have some interconnection procedures for DERs, respondents from 13 states believe these procedures would definitely or probably apply to micro-grids; 6 states indicated that these procedures would definitely or probably not apply to micro-grids; and 5 states indicated that it was unclear. Among respondents from the 19 states that have technical interconnection requirements, 11 respondents believed that such requirements would definitely or probably extend to micro-grids in their states; 4 indicated that they would probably not extend to micro-grids; and 4 were unsure.

Responses from regulatory officials paint a muddy picture for parties interested in constructing an interconnected micro-grid. Interconnection procedures and technical requirements are often not designed well or not easily enforceable. In an effort to limit the risk to utility customers and line-workers, utilities are sometimes given the power to increase the rigor and cost of interconnection studies – generally at the expense of the customer-generator. This places all of the burden of proof on the customer-generator and can result in overly stringent and/or overly expensive interconnection requirements. (Alderfer et al., 2000)

It is the responsibility of regulators to ensure that interconnection procedures and technical interconnection requirements are designed and enforced in a manner that is fair and reasonable for both parties. If implemented in a balanced manner, many of the model standards that have been developed by NARUC, PJM, etc. seem to accomplish this successfully.

Table 21 demonstrates that although states are generally making progress in addressing the barriers to DER development, there is still substantial uncertainty for micro-grids. Even this picture is incomplete. Among the 27 states involved in the study, *only 4 states* – Georgia, Missouri, Pennsylvania, and Minnesota – indicated that 1) micro-grids may be legal under some circumstances; 2) there are existing tariff arrangements, interconnection procedures, and technical interconnection requirements for traditional DERs; and 3) all of these stipulations would definitely or probably apply to micro-grids.

A recent review of European policies for DER interconnection (ELEP 2005) concludes that the European community suffers from considerable uncertainty and opacity that "underlines the urgent need for a novel, consistent and pan-European approach to DG interconnection issues." This report does not address micro-grids in particular, but the uncertainty in interconnection policy is considered a barrier to all DER applications. Individual nations, most notably the Netherlands, have imposed regulations that favor interconnection for DERs so there are success stories and a working framework for progress.

3.3.4 Regulatory oversight of micro-grids

Before regulators allow micro-grids to be installed and operated, most want some assurance that micro-grids will have a positive impact on society, and that they will not be able to operate in a regulatory loophole that enables them to mistreat their customers or sidestep environmental laws and participation in social programs. These assurances traditionally come in the form of regulatory controls. In the case of owner-customer interactions, they may also be provided by contractual agreements. This section addresses whether and to what extent micro-grids are or could be subject to regulatory oversight.

Micro-grid customer interactions

One of the roles of the regulatory community is to ensure that the public is protected against unreasonable rates, bad service, and negligence that results in safety or human health risks. It is a matter of interpretation whether this responsibility applies to customers that willingly agree to the provision of electricity and heat from an independent micro-grid. Although some regulators have expressed concern over the manner in which micro-grid firms might provide service to its customers, it is unclear how this relationship is defined in regulatory law.

A micro-grid, by definition, involves multiple customers and essential services for electricity and heating. When one also considers that customers may not fully understand the technical aspects or risks associated with energy quality and reliability, it is clear that the State has an interest in providing guidance, if not legal requirements, for how a micro-grid is managed and operated. The dynamic between the micro-grid owner/operator and its customers will depend on which type of micro-grid is installed (e.g. Landlord model, Co-op model, District Heating model), but there are several issues that deserve consideration. They include but are not limited to: rate-setting; billing and collection; dispute resolution; insurance holdings; credit; and demand management for reliability.

Many of these issues are currently handled in rules designed for public utilities. In the survey, regulators from several states suggested that these rules would likely apply to micro-grids. However, since micro-grids are most likely to operate without public utility status in most states, the relevance of such laws is unclear. Respondents from a few states indicated that consumer protection laws would probably apply, but did not know what this meant in terms of specific requirements. Most respondents indicated that such issues would be handled on a case-by-case basis, subject to interpretation by the regulatory authority. This implies that customers may face high transaction costs and potentially significant delays.

While protection for micro-grid customers is important, it is likely that ad-hoc requirements set by the regulatory authority would be inefficient for both the micro-grid and regulators, and would likely lead to requirements that are either overly stringent or focus too much attention on certain issues such as rate-setting. On the other hand, adopting broad, uniform standards – especially if they are based on current rules for public utilities – may be very burdensome and limit the ability of micro-grids to cater to specific customer needs.

The Dutch Electricity Act of 1998 seems to provide balance between protecting micro-grid customers and enabling flexibility and innovation. Micro-grid systems that are exempted by Article 15 of the Act face technical and administrative requirements, but are generally freed from many of the price, operational and administrative regulations faced by utilities (Pudjianto et al., 2005b).

Environmental and siting laws

When asked about environmental and siting laws, most respondents indicated that it was outside of their jurisdiction and they were reluctant to offer much interpretation of the law in this area. Environmental issues are typically handled by a state environmental protection agency and/or local air quality regulator. Siting is often handled by local agencies, especially when the proposed plants are fairly small.[21] Despite the lack of jurisdiction, questions and concerns about the environmental

[21] For example, power plants that are smaller than 25 MW are exempt from state regulation in Iowa and Oregon. Plants under 75 MW are exempt from state regulation in Florida and South Carolina. Plants under 100 MW are exempt from state regulation in Wisconsin.

impacts of micro-grids did arise in conversations with regulators and it is worth some discussion here.

Micro-grids with CHP have three important impacts on environmental and human health quality. First, they move the production of electric power and its resulting emissions nearer to population centers, which may increase the harmful effects of certain air pollutants (e.g. SOx, NOx, PM). Second, by capturing heat from the generators, they displace combustion from gas boilers and water-heaters and possibly reduce cooling loads through the use of adsorption chillers or dessicants. Third, they alter the traditional emissions control regime by replacing large, customized, centralized plants with small, off-the-shelf, distributed plants.

The proximity of DERs to population centers is and should be a concern to regulators (Gulli 2004; Heath et al. 2005). The increased risk associated with localized emissions from DERs can, depending on the design, be offset by the use of CHP applications that not only improve overall efficiency but also obviate the use of gas-fired boiler systems (Strachan and Farrell 2004). DERs and micro-grids can also make use of environmentally benign fuel sources, and provide opportunities for clean generating technologies such as photovoltaics, small-scale wind turbines, and fuel cells.

The dispersed nature of DERs presents some pragmatic concerns about the ability of micro-grids to control emissions in response to future regulatory action. Large plants may be easier to monitor and control because they are fewer in number, but the regulation of multiple sources in the automobile and aerospace industries has been effective thanks to the presence of pre-designed, pre-fabricated, off-the-shelf technologies. This may be a useful model for emission control in micro-grids, since the cost-effectiveness of these systems will depend on the mass-production of their components. As more stringent emissions controls are required, generator manufacturers will have to develop and adopt design changes to make next-generation equipment that is compliant with new aggressive air quality targets.

Public programs

Many states have public programs known as public benefit trusts that are designed to encourage energy-efficiency, provide support to older and low-income households, encourage research and development, etc. These programs are funded through small usage fees that are levied against utility customers, and money is awarded through the State.

If micro-grid customers are granted the right to operate without utility status, they may not be legally required to participate in these programs. This is a small problem if micro-grids remain a niche, but as micro-grids market penetration increases, regulators may want to require micro-grid customers to participate in public programs and make micro-grid customers eligible to receive benefits from these programs.

3.4 Recommended Regulatory Changes

An uncertain regulatory environment poses an unnecessary barrier to the development and adoption of micro-grid systems. Regulators and legislators should create new rules and laws and make changes to existing ones so that micro-grids systems can participate and compete in a new market for energy and energy services. These changes need to be effective, while still limiting system risk and protecting the rights of both the micro-grid and the utility customers. The following are a set of regulatory changes that can be adopted to facilitate measured, low-risk micro-grid development. These changes can be written into law by legislators or created within rules by regulatory agencies.

Policymakers are encouraged to adopt these changes now, while there is considerable activity in the arena of distributed energy resources.

Formalize the definition and legal rights of micro-grids

Micro-grid owners should have the right to provide electricity and heat to interested co-located customers. Micro-grids should have the right to buy from and sell to the local electric utility, and negotiate bilateral agreements with the utility to provide ancillary services. Micro-grids should have the right to buy and sell on the wholesale market. Regulatory law may want to recognize different types of micro-grids (e.g. landlord model, co-op model) and customize licensing and interconnection procedures for each type.

Require utility tariffs for micro-grids

Utilities should be required to develop and submit tariff structures that specifically apply to micro-grids. Like other tariffs, these should be subject to review and scrutiny by state PUC/PSCs. Regulators should not allow tariffs to be punitive or discriminatory, and for reasons articulated in the next chapter tariffs should not include standby fees based on installed capacity. Such fees do not provide micro-grid operators with any incentive to design or manage their system optimally to reduce the utility burden. Standby fees should instead be replaced by demand charges and emergency standby rates, which incent micro-grid operators to adopt measures that are economically sensible and mutually beneficial, including internal redundancy, demand response measures, and aggressive maintenance schedules.

Adopt standardized interconnection procedures that are applicable to micro-grids

Regulators should consult the model interconnection procedures developed by NARUC and implemented in many states, and make these types of procedures applicable to micro-grids. Timelines, procedural steps, and the responsibilities of both parties should be clearly laid out.[22] These procedures should be mandatory, not voluntary, and utilities should not be able to impose additional studies without clear justification. Additionally, PUC/PSCs should develop and maintain a list of interconnection and generation equipment that is pre-certified.[23] Micro-grids that use this pre-certified equipment should be granted expedited processing.

Limit system and utility risk

Regulators should adopt standardized minimum technical interconnection requirements that are applicable to micro-grids. In many cases, this may only involve an extension of existing DER requirements to micro-grids. Technical requirements – and associated equipment requirements – should not be subject to much interpretation or expansion by the utility without approval from regulators.

If regulators are concerned about the system impacts of emerging micro-grid growth, they may choose to initially limit the number or size of interconnected micro-grids. However, these limits should be set based on demonstrable deleterious system impacts, not politics.[24] Regulators should also promote tariff design that encourages micro-grid development in areas of the grid that are congested or experiencing rapid demand growth.

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[22] The Texas Distributed Generation Interconnection Manual, most recently revised and published by the PUC of Texas in May 2002, is a good model for clear, standardized interconnection procedures.

[23] See the California PUC (http://www.energy.ca.gov/distgen/interconnection/certification.html) and the New York PSC (http://www.dps.state.ny.us/SIRDevices.PDF) for examples of pre-certified equipment lists.

[24] For example, Texas DG interconnection laws apply to customers with 10 MW of capacity or less, and proposed FERC interconnection procedures for small generators will apply to systems with 20 MW of capacity or less.

Micro-grid owners and operators should be required to provide utilities with information that will affect planning. Utilities should receive information about capacity, system design, and location well before a micro-grid is constructed and interconnected. Utilities should also receive advanced notice of planned micro-grid outages due to maintenance, upgrades, etc.[25]

Formalize the responsibilities of micro-grid owners

Regulators should construct clear rules or guidelines for how micro-grid owners interact with their customers. States may want to require licensing procedures for billing, collecting, dispute resolution, insurance, credit, etc. These procedures should be limited in scope so as to reduce cost and administrative burdens for the micro-grid and the State. Regulators should look for precedent and guidelines from rules and requirements that exist for similar systems, such as district energy plants and energy service companies (ESCOs). There are district energy systems in 38 states[26] and in most cases these systems serve a small, contiguous group of customers and strongly resemble the structure of a micro-grid. The energy services industry is a multi-billion industry in the U.S. that is active across the country (Osborn, Goldman et al. 2002) and although ESCOs usually serve individual customers based on contractual agreements, these services often include installation and management of infrastructure (HVAC equipment, building improvements, etc.), and may provide a useful model for insurance and credit requirements.

The State should develop model contract language to encourage bilateral contracts between micro-grid owners and micro-grid customers, and to ensure that such contracts are clear and

[25] This type of information exchange is typically defined within the "maintenance power" component of current utility tariffs for customer-generators.
[26] According to the International District Energy Association, http://www.districtenergy.org/city_system_list.htm.

understandable for consumers. According to survey respondents, the use of contracts could reduce the need for regulatory oversight. This reduced oversight can save the customers and the State valuable time and money.

Micro-grid operators should provide information to utilities and the State both prior to and during operation. This information should include installation plans (schedules, capacities, expected demand, etc.) as well as operational plans (scheduled maintenance outages, estimates of unscheduled outages) that can be used by utilities and system operators when making plans for new capacity upgrades or additions.

Micro-grids should be required to participate in public programs such as Public Benefit Funds, and both the owners and the customers should be eligible for benefits from such programs. Provision of information to the utilities and the State for public programs should be mandatory.

One relevant international model for regulation of micro-grids is the Dutch Electricity Act of 1998, which seems to provide balance between protecting micro-grid customers and enabling flexibility and innovation. Micro-grid systems face technical and administrative requirements, but are generally freed from many of the price, operational and administrative regulations faced by utilities. (Strbac et al. 2005)

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Chapter 4. Utilities and Customer-Generators: The Effect of Tariff Design on Adoption and Management of Distributed Resources

4.1 Introduction

Electric utilities have historically viewed customer-generators – those who have their own on-site generation – as financial, technical, and safety risks. As regulated monopolies, vertically-integrated utilities and distribution companies have been presented with both the obligations and the benefits of providing universal service, and customer-generators have been perceived largely as a potential disruption to the security and predictability of utility services and a threat to their monopoly position (see Alderfer et al. 2000 and Johnson 2003 for relevant case studies and interviews).

In recent years, a legislative and regulatory focus on competition and customer choice, together with a demand for higher reliability and power quality, and growing awareness of the value that distributed energy resources (DERs) can have for a healthy grid, has led to industry restructuring that allows a greater role for customer-generators. Following the lead of large states such as Texas and New York and organizations such as the National Association of Regulatory Utility Commissioners (NARUC), the Federal Energy Regulatory Commission (FERC) and numerous states regulatory commissions have adopted standards and procedures that allow customer-generators with as much as 10 or 20 MW of capacity to interconnect with the local distribution system.

As regulatory changes have opened the door for interconnection of more and larger DER systems, the financial stakes for utilities and their customers have increased. The result is a set of new issues concerning the rights and responsibilities of both utilities and customer-generators. As with industry restructuring in general, the emergence of competitive DER options forces regulators to balance various trade-offs. In this case, the trade-off is between stability and fairness to the utility on one hand and innovation, competition, and choice on the other.

At the heart of this transition is the pragmatic consideration of tariff design. Proper tariff design has several competing goals that have significance both for the utility and its customers. In this chapter, I re-visit the goals of utility tariffs, and evaluate the tariff components that are most commonly employed for customer-generators. I explore three questions: 1) what, if any, are the extra costs that customer-generators impose on utilities; 2) what, if any, are the benefits that customer-generators may impart to the utility and its conventional customers; and 3) what is the most effective, economically efficient, and socially appropriate method for utilities to recover any net costs from customer-generators?

After briefly explaining the basic analytical approach, in Section 2 I review and extend the goals of utility tariffs and discuss tariff components commonly employed for customer-generators. Section 3 examines the costs and benefits that customer-generators impose on utilities. In Section 4, I present the results of a model that demonstrate how various tariff components affect the profitability and decision-making of customer-generators, and how this decision-making consequently affects the utility. Finally, the results of the study are summarized and a set of recommendations are provided for utilities and the regulatory community.

4.1.1 Analytic method

Analytical results for this study have been produced using the micro-grid customer engineering-economic model (MCEEM), described in Chapter 2, to identify optimal short-term and long-term customer-generator decisions in response to various endogenous and exogenous factors. The MCEEM was originally designed to model only micro-grid systems, but can be used to model any small system with multiple generators. The natural gas rate used throughout this chapter ($10/MBTU) was updated from those used in Chapter 2, to reflect increases over the past few years.

Generally, a micro-grid is a small network of distributed energy resources coordinated in a grid-like fashion to provide electric power (and commonly heating and/or cooling) to multiple co-located customers. Micro-grids are usually interconnected with the utility grid at distribution voltages, and can operate either in parallel with the grid or as an island.[27]

The MCEEM assumes that customer-generators will operate their DERs so as to minimize total energy (electrical and heating) costs over the life of the project. The MCEEM optimizes both hourly dispatch and long-term capital investment (i.e. capacity installation) decisions to maximize present value for the customer. Customer-generators do not operate their DERs in a binary (on/off) fashion, but make hourly decisions based on internal heat and electricity demand, utility gas and electricity prices and on-site equipment constraints (e.g. capacity limits, availability) and efficiency curves. Capital investment decisions concerning the number, type, and capacity of generators to

[27] There is no single authoritative technical or regulatory definition of a micro-grid. Recent work discussed in Chapter 3 has shown that the regulatory definition and legal status of a micro-grid depends on various factors, such as ownership, number of customers served, etc. A questionnaire of the 2005 Micro-grid Symposium attendees did not yield a consensus definition, but showed general agreement of the important characteristics, all of which are included in the definition provided here. Questionnaire responses are on-line at http://der.lbl.gov/CERTSmicrogrids.html.

install are also optimized, and since customers are not required to install any minimum level of capacity, they may choose not to install a micro-grid at all.[28]

Analyses presented in Chapter 2 demonstrated that micro-grids can be more profitable than conventional DG projects, and that profitability depends on the application (e.g., customer configuration), local utility tariffs, and location (climate) of installation. For this analysis, two different applications – a hospital complex and a high-rise – were modeled in two different locations – Minneapolis, MN and San Diego, CA.[29] Multiple scenarios were modeled in an effort to make the results of the analysis more generalizeable and robust; these particular scenarios were chosen because they capture most of the variation of the results from chapter 2.

4.2 Utility Tariffs – Purpose and Components

In principle, public utility rates serve two simple functions: to recover utility costs with a fair return, and to provide socially optimal price signals to customers. In practice, utility rate design is often highly contentious and involves a great deal of muddling through. This problem persists in regions with traditional, vertically-integrated utilities as well as regions with restructured retail markets. In regions with restructured retail markets, generation companies set rates in a competitive environment, but regulators still have a great deal of control because generating firms often have market power and legislators have been afraid to allow generating companies to set rates without caps or contingencies. Also, distribution companies are still granted regulated monopolies, so rate components dedicated to electric power distribution and direct customer services are still regulated under the traditional framework. These distribution companies also often operate as the "provider

[28] More detail about the MCEEM is available in (King and Morgan 2006b).
[29] Hourly electric and heat demand profiles were generated for each scenario using the DOE-2.1 back-end of ORNL's BCHP Screening Tool (ORNL 2004). Each building on the micro-grid was modeled separately and the results were aggregated. These demand profiles became inputs for the MCEEM.

of last resort", responsible for meeting customer demand in case market suppliers default or leave the market.

Legal and scholarly debates in the first half of the 20^{th} century focused on the kinds of costs that should be recoverable (i.e. the rate base), the rates of return that utilities should receive on their investments, whether and how customers should be grouped, and the competing goals of equity and efficiency (Bonbright et al. 1988, Kahn 1988). More recent debates explore how best to reflect long-run marginal costs so that customers would face price signals that were socially optimal. Although some of these issues remain unresolved, scholars have reached a general consensus on the competing criteria for "fair return" by public utilities. These criteria are characterized by the goals they are meant to achieve:

1) Attract capital for the utility. If utility investors do not receive a reasonable return, it is possible that future capital investment will dry up and the utility will not be able to carry out its function.
2) Encourage efficient management practices. Rate design should incent utilities to minimize costs wherever possible, in turn keeping consumer prices down.
3) Promote socially optimal consumer choices. Prices that do not accurately reflect the cost of service can encourage customers to over- or under-consume, resulting in a net social economic loss.
4) Ensure fairness to investors. Since the State confers unique and important rights and responsibilities on public utilities, utility investors expect the State to protect their interests and allow a fair return on investment.

5) Provide a stable and predictable rate level. Fluctuating rate levels inhibit efficient long-term decision-making by customers and impose an administrative burden on the utility.

Throughout this chapter, I refer to these criteria when assessing the appropriateness and efficacy of different tariff components for customer-generators. In addition to these traditional criteria for fair return to public utilities, I propose that two additional goals deserve attention in the context of rate-making for customer-generators:

6) Encourage efficient management and use of customer-generator resources. Rates should reflect the total costs imposed by customer-generators on the utility, and provide customers with an incentive to install and manage their DERs so as to limit these costs.

7) Compensate customers for services rendered to the utility. Unlike conventional customers,[30] customer-generators can provide services to the utility (e.g. power, ancillary services, voltage support) to the utility, for which they deserve remuneration.

In addition to the goals discussed above, regulators may find that the public interest is best served through promotion of DERs or other technologies. For example, regulators may want to promote renewable resources to reduce environmental impacts or encourage the market for DERs to induce innovation and competition. Rate theory argues against manipulating rates to promote social interests because it can result in inefficient consumption and unexpected outcomes (Bonbright et al. 1988, Kahn 1988). However, since tariffs are rarely strictly cost-based, and regulators face practical

[30] The term "conventional customer" will be used throughout to describe customers with no DERs installed on-site and no utility-operated automatic load control or load shedding.. When comparisons are made, hourly conventional customer demand is identical to customer-generator demand.

constraints on their time and methods for implementing various legislative mandates, tariffs are often used to achieve multiple purposes. This is apparent in several states, where regulators have reduced or eliminated certain tariff components for DER systems that meet specified efficiency or environmental criteria. However, in this analysis only the costs and benefits that customer-generators impose directly on utilities will be considered.

An excellent review of existing rules and rate structures for customer-generators was recently completed for the National Renewable Energy Laboratory (Johnston et al. 2005). This work provides a thorough summary of current and proposed ratemaking policy in ten different states, and lays out important issues that have been or should be considered by regulators.

The remainder of this section presents different utility tariff components, including how they are applied and whether and how they meet the criteria listed above – both in theory and in practice.

4.2.1 Energy consumption charges

Energy consumption charges are based on aggregate monthly energy (kilowatt-hour, or kWh) consumption, and are included in all tariffs. Rates vary considerably throughout the country and across different customer classes. Residential customers typically have much higher rates than commercial or industrial customers. Energy rates are updated periodically (e.g. annually) to adjust for changes in fuel and other costs, and like all utility rates they are subject to review by state regulatory authorities.

In theory, energy charges are meant to be cost-based to give customers accurate price signals and recover costs for utilities. From the standpoint of economic efficiency, energy rates should perfectly reflect the short-run marginal cost of energy production and delivery for each customer. In practice, various technical, administrative, and cost considerations prevent this. For example, capital investments represent a considerable percentage of the overall cost of operating an electric utility, and regulators allow utilities to recover a portion of these costs via energy charges. Other costs, such as system administration, insurance, taxes, etc. are also commonly bundled into energy charges. Such bundling is generally considered necessary to ensure that utilities can receive a fair return and continue to attract capital and fulfill their obligations to customers.

Customers are grouped into classes (e.g., industrial, commercial, residential) that theoretically have similar consumption patterns and similar costs. In a conventional tariff, costs are averaged over time, and energy rates do not vary based on time of day. Prices do change seasonally to reflect variations in the cost of fuel or system congestion.

Some customers are offered time-of-use pricing schemes, which include "tiers" for different blocks of time during the day to reflect the higher cost of generating and supplying power during times of high demand. Time-of-use rates are a reasonable compromise between efficient consumer rationing and manageable and predictable rate levels, but they don't capture the full time-dependent variability in costs.

4.2.2 Demand Charges

Demand charges are assessed against a customer's maximum monthly kilowatt (kW) demand, and they are typically included in the tariff structures for commercial and industrial customers. Generally, the demand charges paid by a customer is the product of the demand rate ($/kW) set by the utility and the highest average hour or quarter-hour of demand (kW). In many cases, only demand that occurs during peak system periods is considered.[31]

Operation during system peak periods is more expensive because peak generators are less efficient, and transmission and distribution (T&D) losses are higher due to congestion. Most importantly, since peak period infrastructure only operates a small fraction of the year, the capital costs per kWh served are very high. Demand charges are designed to address these costs and in theory they serve two functions: enable utilities to recover the extra costs associated with installing and operating peak generation and T&D capacity, and provide an incentive for consumer rationing during these expensive peak system periods.

Demand charges do recover costs for the utility, but they fail as an efficient mechanism for consumer rationing on two accounts. First, customer peak demand is only probabilistically coincident with the overall system peak, which means customers may pay prices that do not fairly reflect the actual costs they impose on the system. Second, although demand charges are designed to recover both capital and operating costs associated with peak supply, they don't necessarily provide customers with an incentive to reduce aggregate consumption during peak periods.

4.2.3 Standby charges

Standby charges, also known as "reservation fees", are unique to customer-generators, and they are most commonly assessed per kilowatt of installed nameplate capacity. A quick survey of public

[31] Every utility has their own definition of system peak periods for rate-setting, but they are commonly weekday work hours. In this analysis, "system peak period" is defined as 7 AM to 9 PM on non-holiday weekdays.

utilities across the country reveals that nearly 75% of utilities that have published tariffs for customer-generators utilize some form of standby charge.[32]

Standby charges serve the singular purpose of recovering the cost that the utility has to bear for the risk of serving a customer whose demand may suddenly spike when their on-site generation resources fail. Commonly, the charge is fairly high (typically $3-8/kW per month, varying widely across the country), and it is justified by the utility claim that for every kW of customer-generation, the utility must have one kW of standby power available.

In practice, standby charges often recover costs that far exceed the risk that customer-generators impose on the utility – a topic to be explored in Section 4.3. Further, these charges provide no incentive for customers to either consume or operate efficiently because standby charges cannot be mitigated through better system design or operation, or improved demand management.

4.2.4 Exit fees

Exit fees are typically assessed as one-time charges, or additional per-kWh charges. Exit fees are most commonly associated with industry restructuring, and their purpose is to recover the stranded costs associated with infrastructure that the utility has already financed but that no longer generates revenue for the utility.

[32] In some cases, utilities allow customers to contract for standby capacity that is less than 100% of their installed capacity. In others, standby rates are set based on the expected system performance. In these cases, customers have some incentive to make decisions that are economically efficient for the entire system, but this chapter will focus on the more common practice of charging customers based on installed capacity.

Exit fees are not yet a substantial concern for customer-generators, but there are some cases where utilities have invoked the concept of stranded costs to justify charging exit fees. Exit fees imposed on customer-generators have the effect of discouraging investment in DERs and do nothing to encourage efficient consumption or resource operation.

Whether stranded cost recovery is justified depends on the details of the grid system being discussed. However, one can argue that the geographic regions where DERs are most likely to be cost-effective are the same regions that most suffer from congested T&D systems and growing electricity demand. In these areas, DERs are likely to provide relief and positive value, not strand costs (Shirley et al. 2002, Dossey 2005).

4.3 Utility Costs and Benefits Associated with DER Customer-generators

In addition to possibly imposing costs on a traditional utility, DERs may also provide a number of benefits. In July 2004, the California Energy Commission prepared a qualitative but thorough assessment of the various costs and benefits associated with DERs in response to the California Public Utilities Commission new rulemaking, R.04-03-017 (Gumerman et al. 2003). The CEC findings revealed 15 different costs, and 17 different potential benefits (see Appendix C, Figure C-3). Here, only those costs and benefits that are significant and immediately relevant to the question of rate-setting are examined.

4.3.1 Costs of providing standby service

The federal Public Utility Regulatory Policies Act (PURPA) prescribes the provision of three types of service to customer-generators: supplemental power; maintenance power; and backup (or standby) power. Supplemental power is provided to customers that do not install capacity to meet

100% of their demand, and it refers to the demand that exceeds on-site production capability. Maintenance power is provided to meet demand during scheduled outages. Back-up power is provided to meet demand during unscheduled outages. While the term "standby service" commonly refers to both maintenance and backup power, the focus of this section is on back-up power, since there is relative consensus on pricing for maintenance and supplemental power. All three types of service may include consumption charges, demand charges, and/or standby charges.

When a customer-generator experiences an unscheduled outage, the utility must have the necessary generation, transmission, and distribution resources to provide uninterrupted service to the customer. The "fair return" criteria discussed earlier suggest that the costs associated with these services should be recoverable,[33] but calculating these costs can be very challenging. The true cost of providing standby power depends on the utility's costs, existing infrastructure, the location and demand profile of the customer, etc. These complicating factors create an asymmetry of information, which gives utilities an advantage over customer-generators and regulators in rate-setting disputes.

One way to estimate the cost of standby generation is to use market prices for various types of ancillary services, such as synchronous or non-synchronous spinning reserves. These ancillary services are a reasonable proxy for the type of services that a utility will need to procure for customer-generators on its system. These services do not represent the cost of providing actual power, but rather the cost of having access to the resources when necessary. Table 22 presents the cost of various ancillary services in regions across the U.S.

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[33] Kahn (1988) argues that only non-marginal costs should be recovered through rates, but utility case law history shows that regulators consider it a right of utilities to recover sunk costs.

Table 22. Ancillary Services Market Clearing Prices, 2004 ($/MW)[34]

ISO	Regulation	Synchronous spinning reserves	Non-spinning operating reserves
NYISO	$ 22.60	$ 2.40	$ 0.30
PJM	$ 32.60*	$ 7.40	$ 0.23
ERCOT	$ 10.30	$ 7.60	$ 2.40

* Regulation data is from PJM's mid-Atlantic zone

Estimating the contribution that an individual customer makes to the costs of a T&D system is difficult, and will depend on the particular details of each case. When a section of the distribution network is uniquely dedicated to one customer, the associated costs are typically the responsibility of the new customer, whether that customer has on-site generation or not. The remainder of the customer's impact on T&D costs cannot be calculated without utility-specific information, but as soon as there are more than a small number of such customers with generators, one can show that the system does not need 100% standby T&D capacity for each customer-generator.[35]

The need for both generation and T&D reserve capacity (and any associated costs) should be estimated within the context of a large system serving multiple customer-generators. Large system operators do not require complete system redundancy, and it is unreasonable to expect this kind of robustness from customer-generators. The true cost that a customer-generator imposes on the utility will depend not only on the number of generators and the risk of failure for each generator on the

[34] Although 2005 energy market prices increased considerably over 2004, data from ancillary service market prices for the first half of 2005 do not show a consistent increase.

[35] Regulatory community should be concerned with "order effects", in which early adopting customer-generators are forced to pay a much greater penalty than late adopters. This problem is handled effectively, if not elegantly, by ISOs when determining the cost that a new power plant will have on T&D system costs. Typically, ISO's develop an estimate of the additional costs that a new plant will impose on the system, but wait a period of time (6-24 months) to see how new projects will affect these costs (through cost sharing, or multiplicative effects) before finalizing the full cost estimate. In the case of customer-generators, regulators could require that the total costs imposed by a customer-generator not be calculated until a grace period has passed during which new customer-generators may have joined the system. In the meantime, regulators could allow some cost-recovery based on estimates of system growth, anticipated interconnections, etc.

customer's system, but also the number and failure probability of other customer-generators interconnected to the utility network.

To demonstrate this point, I constructed a simple numeric model to test how the need for utility standby capacity is affected by a) the number of customer DERs on the system, and b) the forced outage rate of individual customer generators. The model calculates the probability that multiple simultaneous failures will occur, for a given number of interconnected DERs at a given outage rate. Based on these calculations, the model determines the amount of standby capacity (as a % of total DER capacity) the utility needs to have in order to ensure that the system has sufficient generation resources 99.999% of the time. For simplicity, all of the DERs are assumed to be equal in size and have an equal forced outage rate, and DER failures are assumed to be independent (i.e. there are no common failure modes).

While this calculation is not for a real system, the trends are representative and illustrative. If as many as 100 generators interconnect with the utility network, and each has a forced outage rate of 5% - a reasonable rate for most DER technologies – the system only requires 20% redundancy. Clearly, a utility system with many customer-generators will not require 100% redundancy, and the need for standby decreases as the number of interconnected DERs increases. Moreover, if customers can improve the reliability of their generation assets, the need for redundancy by the utility is further reduced.

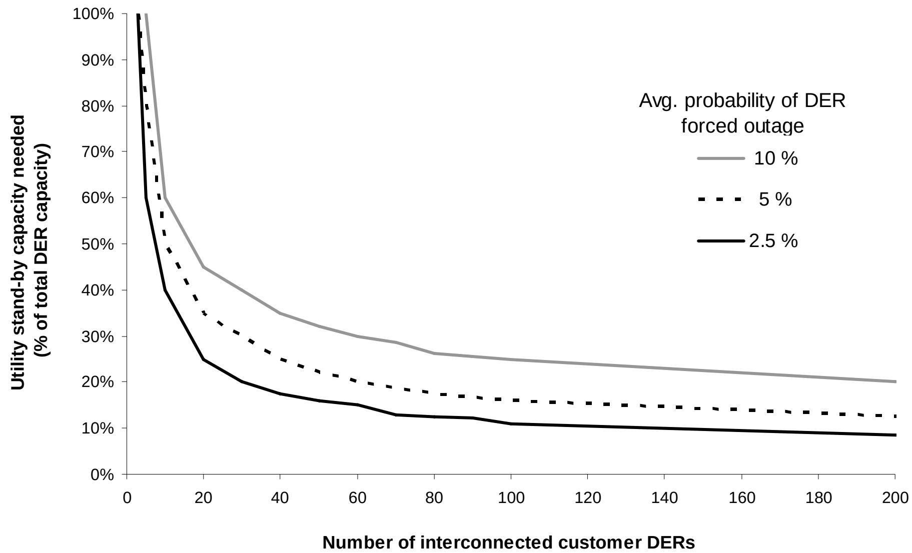


Figure 8. The amount of standby capacity a utility needs depends on both the number of interconnected customer generators and their availability (rate of forced outage). As the number of DERs increases, the probability of a coincident failure declines. Similarly, as customer-generator availability increases, the probability of coincident failures declines and less utility standby capacity is needed.[36]

These conclusions are contingent on the absence of common failure modes. If some unforeseen force does cause multiple DERs to fail simultaneously, the utility could find itself with insufficient standby capacity. The most plausible common failure modes are faulty equipment design and fuel interruptions. If there is a heterogeneous mix (i.e. different types, models, capacities) of DERs installed by customer-generators, the probability of the former should be quite low. The possibility of a fuel interruption, though very unlikely, is more of a threat to utilities. However, utilities can shift this risk to customer-generators by including contractual stipulations stating that, for example, wholesale spot market rates will be assessed during localized natural gas distribution system failures.

[36] It is assumed that DER failures are not correlated. The data presented in Figure 8 are predicated on five nines (99.999%) of reliability, so the utility will only require additional capacity 0.001% of the time. This is far more robust than the "n-1" standard for centralized generation.

In addition to improving the reliability of DERs, customer-generators can also reduce the need for utility standby capacity through the provision of "physical assurance".[37] Physical assurance refers to the ability of customer-generators to reduce demand automatically when a forced outage occurs on their system, and it is usually achieved by integrating interconnection switches and controls with on-site demand management. The concept of physical assurance has already gained attention in several states because it provides customer flexibility while managing utility risk (Johnston et al. 2005). Utilities and regulators should educate customer-generators about various physical assurance strategies, and provide some incentive for their adoption.

4.3.2 Stranded costs

The argument above suggests that the expected standby costs imposed by customer-generators depend on the probability of coincident failures throughout the system. However, utilities may argue that, regardless of its current usage, an investment was made into generation and T&D capacity on behalf of the now-departing customer and that these costs are now stranded.

The issue of stranded costs has drawn much attention in the context of industry restructuring and may find its way into the debate over DERs. However, very few utilities currently impose exit fees on customer-generators. As for the merits of such an argument, there are several possible reasons why utilities have not sought stranded costs from customer-generators: 1) customer-generators are typically small enough that they hardly register a blip on system investment plans; 2) in many cases, given the vintage of electric power infrastructure in most of the country, investments have long been

[37] The California PUC has defined physical assurance as "…the application of devices and equipment that interrupt a distributed generation (DG) customer's normal load when DG does not perform as contracted. An equal amount of customer load to the DG capacity would be interrupted to prevent adverse consequences to the distribution system and to other customers." CPUC Decision No. 03-02-068 Order Instituting Rulemaking into Distributed Generation. Rulemaking No. 99-10-025, Feb. 27th, 2003.

recovered; and/or 3) the regions where DERs make the most sense are also high-growth and/or high-congestion areas in which infrastructure investment is rarely "stranded", and customer-generators can provide positive, not negative, value for the utility.

4.3.3 Benefits of distributed energy resources

Many arguments on behalf of DERs and micro-grids have focused on the potential for improved services and economic savings (Carlson and Hedman 2004, Bailey et al. 2002, King and Morgan 2006, Pepermans 2005, Poore et al. 2002) for customers. Other arguments center on the benefits that DERs may have to society through reduced environmental impact (Strachan and Farrell 2004, IEA 2002, Pudjianto and Strbac 2005)[38], reduced need to build additional power system infrastructure (Shirley 2002, Evans 2005), increased competition and innovation (cite IEA), downward pressure on market prices (Kosanovic and Beebe 2005), improved utility system performance (Evans 2005), or improved system security (Zerriffi and Dowlatabadi 2002). These benefits deserve attention from policy-makers and may justify various actions to encourage the adoption of DERs. However, rate theorists argue that these kinds of external benefits should be accounted for separately and warn that bundling these kinds of impacts into rate-setting can yield unforeseen consequences and inefficient behavior (Bonbright et al. 1988, Kahn 1988). For this reason, this section will restrict its examination to those qualities of DERs that directly offset utility costs and therefore warrant consideration during rate-setting.[39]

[38] Most analyses that reveal net environmental benefits for distributed energy resources assume the utilization of combined-heat-and-power (CHP) applications or renewable energy technologies.
[39] This approach is supported by regulatory bodies. According to the Johnston et al., in 2001 the NYPSC set guidelines for standby rates, writing that rates should reflect the cost of standby, and "should provide neither a barrier nor an unwarranted incentive" for DERs adoption.

There are three primary benefits that customer-generators can provide that directly offset costs: 1) the provision of ancillary and other services; 2) the availability of interruptible loads; and 3) reduced peak demand, enabling better utilization of, and reduced demand for, generation and T&D assets.

Depending on how the system is designed, a customer-generator can provide the utility with various ancillary services, including operating reserves, regulation and load balancing, and voltage support (Joos et al. 2000, Kueck 2003). As controls and automation for utility distribution systems improve, customer-generators will also be able to create local islands in order to provide emergency service to nearby utility customers during grid disruptions. While the value of ancillary services and emergency support may be significant, it is highly variable and probably best captured either through bilateral contracts between the customer-generator and the utility, or participation by customer-generators in organized ancillary service markets.

Certain DER applications, such as micro-grids, are well-suited to offer interruptible load contracts to the utility. Generally, the micro-grid architecture is expected to include intelligent controls to manage internal loads, as well as a tiered design to prioritize loads during islanding (Lasseter et al. 2002). The value of interruptible loads to the utility system is reflected in the lower rates offered to conventional customers willing to shed load upon request.[40] Regulators should require utilities to offer lower-rate interruptible load tariffs to customer-generators, and these tariffs should reflect the full value of this service.

[40] For example, in 2001 the New York ISO found itself short of the necessary reserve margins, and initiated a program to promote DERs and curtailable loads. Customers that could reduce load up to 15 times per year for a maximum of 50 hours were given subsidies of $150 per kW. The 2003 version of the NY program rewarded participants with payments of $10-$70 per kW, depending on location. Information available on the New York State Energy Research and Development (NYSERDA) website, www.nyserda.org/incentives.asp.

Results from the MCEEM indicate that profitable micro-grid applications will have flatter demand profiles and consume less power during peak system periods than conventional customers. This provides value to the utility in two ways – by reducing the energy supply infrastructure necessary to meet peaks, and by allowing the utility to get a better return on its assets. This value is observable in the lower rates that many utilities already offer to customers with flat profiles, and also in the efforts by merchant energy providers in restructured states to cherry-pick customers with flat profiles from incumbent utilities.

Table 23. Comparison of Peak Period Consumption for Customer-generators Versus Conventional Customers, as Estimated Using the MCEEM

	Percentage of total customer-generator kWh purchased from the utility during peak utility periods					
Micro-grid Scenario	Conventional Customer	Micro-grid customers, organized by profitability (NPV)				
		< $1 million	$1-2 million	$2-3 million	$3-4 million	$4+ million
Minneapolis Hospital	52 %	53 %	49 %	43 %	38 %	32 %
San Diego Hospital	52 %	53 %	50 %	40 %	28 %	25 %
Minneapolis High-Rise	78 %	72 %	51 %	40 %	35 %	31 %
San Diego High-Rise	80 %	71 %	50 %	41 %	28 %	N/A

Table 23 demonstrates the relationship between micro-grid profitability and peak demand. Profitable micro-grid systems import less electricity from the utility during peak hours than conventional customers. This trend is the result of three different underlying causes: customer-generators are encouraged to produce during peak hours by utility demand charges; CHP applications make it more efficient for customer-generators to produce power when heat demand is high, which is disproportionately during peak operating hours; and part-load efficiency curves make it more expensive to operate generators below rated capacity during off-peak hours.

Figure 9a.

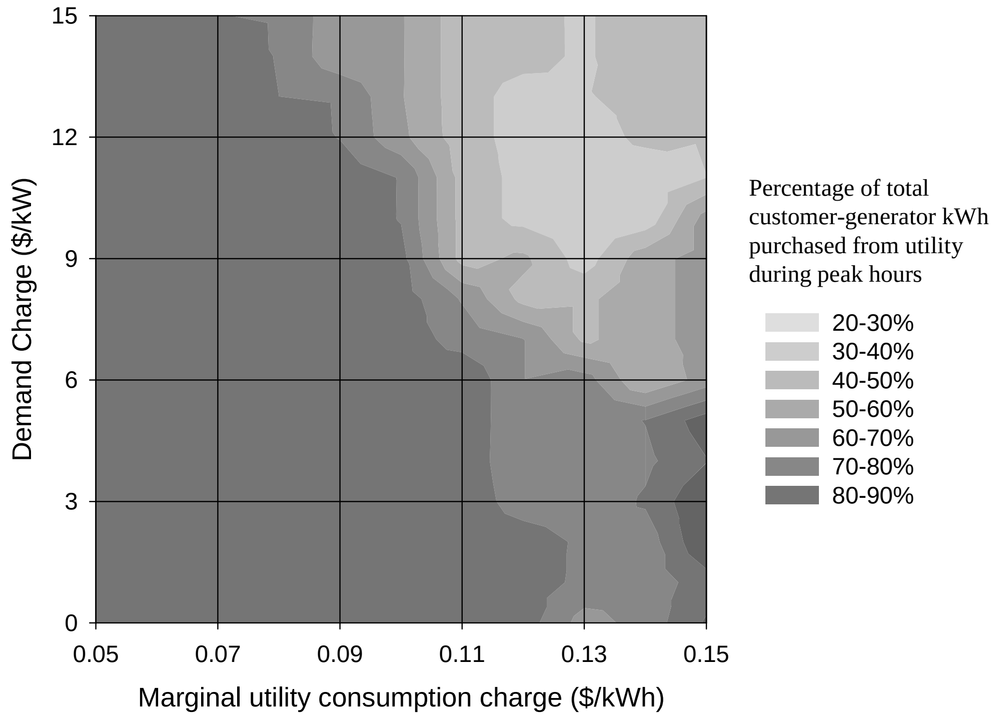


Figure 9b.

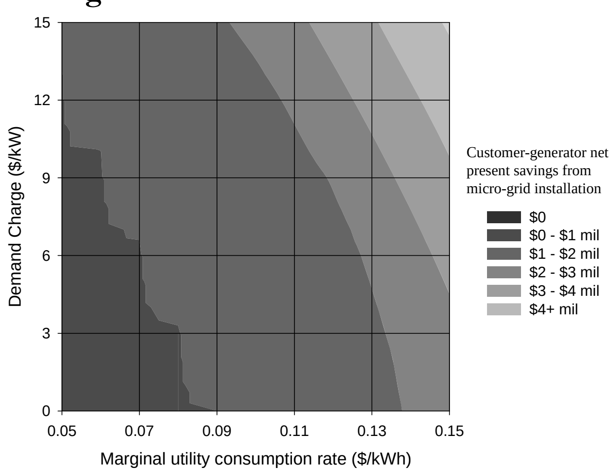
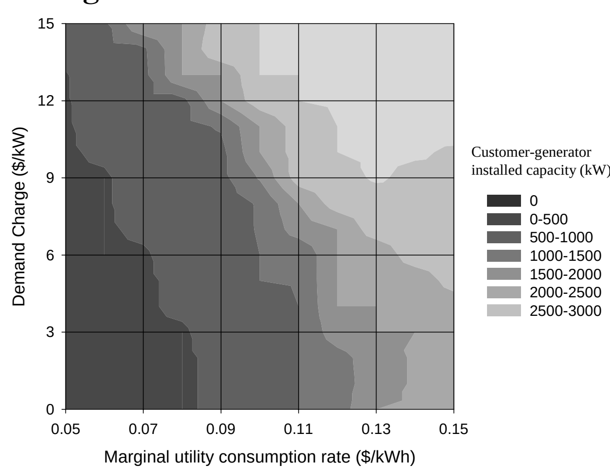


Figure 9c.



Figures 9a - 9c.[41] Peak period consumption (a), present value savings (b) and capacity installation (c) for a micro-grid in a Minneapolis high-rise as a function of utility rates. Contours in (a) represent the percentage of annual power consumption by the customer-generator from the utility that occurs during peak periods. When prices are low, it is not cost-effective to install or operate a micro-grid. As prices increase, the micro-grid becomes more profitable, and customer-generators install more capacity and consume proportionately less power from the utility during peak periods.

[41] Marginal consumption rates refer to the rates for the "last" kWh consumed by the customer. Utilities often set rates based on blocks of consumption, so the first 1000 kWh consumed will cost less per kWh than the second 1000 kWh, and so on. This pricing is designed to reflect economies of scale in generation. In this analysis, we ignore block pricing, and assume that consumption rates are fixed, so marginal rate equal average rate.

Figure 9a shows how changes in demand charge and consumption charge affect consumption by customer-generators during utility peak system periods. As rates increase, it becomes increasingly profitable to install a micro-grid (see Figure 9b), so customer-generators install more capacity (see Figure 9c). Contours represent the percentage of annual power consumption from the utility by the customer-generator that occurs during peak periods. The trends here are representative for the range of customer-generators studied (see Appendix C), and demonstrate that customer-generators have flatter demand profiles than conventional customers. The small peaks and valleys in Figure 9a are the consequence of small shifts in the type and level of capacity installed by the customer-generator, and the effect that this has on hourly dispatch decisions. For example, as the consumption rate increases from $0.13 to $0.15 per kWh, it becomes profitable to install more system peakers, which can be utilized efficiently during off-peak, low-demand hours. As a consequence, off-peak on-site production increases, off-peak purchases from the utility decrease, and the ratio of peak to off-peak purchases from the utility (as seen in Figure 9a) increases.

While DERs may benefit the utility, the quantification of these benefits must be determined in each case. Just as the costs associated with DER interconnection are often determined during feasibility and impact studies, the benefits should also be considered in utility- or customer-funded studies prior to interconnection. Such a strategy has already been adopted by the Minnesota PUC, which has created various credits for customer-generators that can demonstrate that their system meets certain criteria (MN PUC 2004).

4.4 Effectiveness and Efficiency of Different Tariff Components

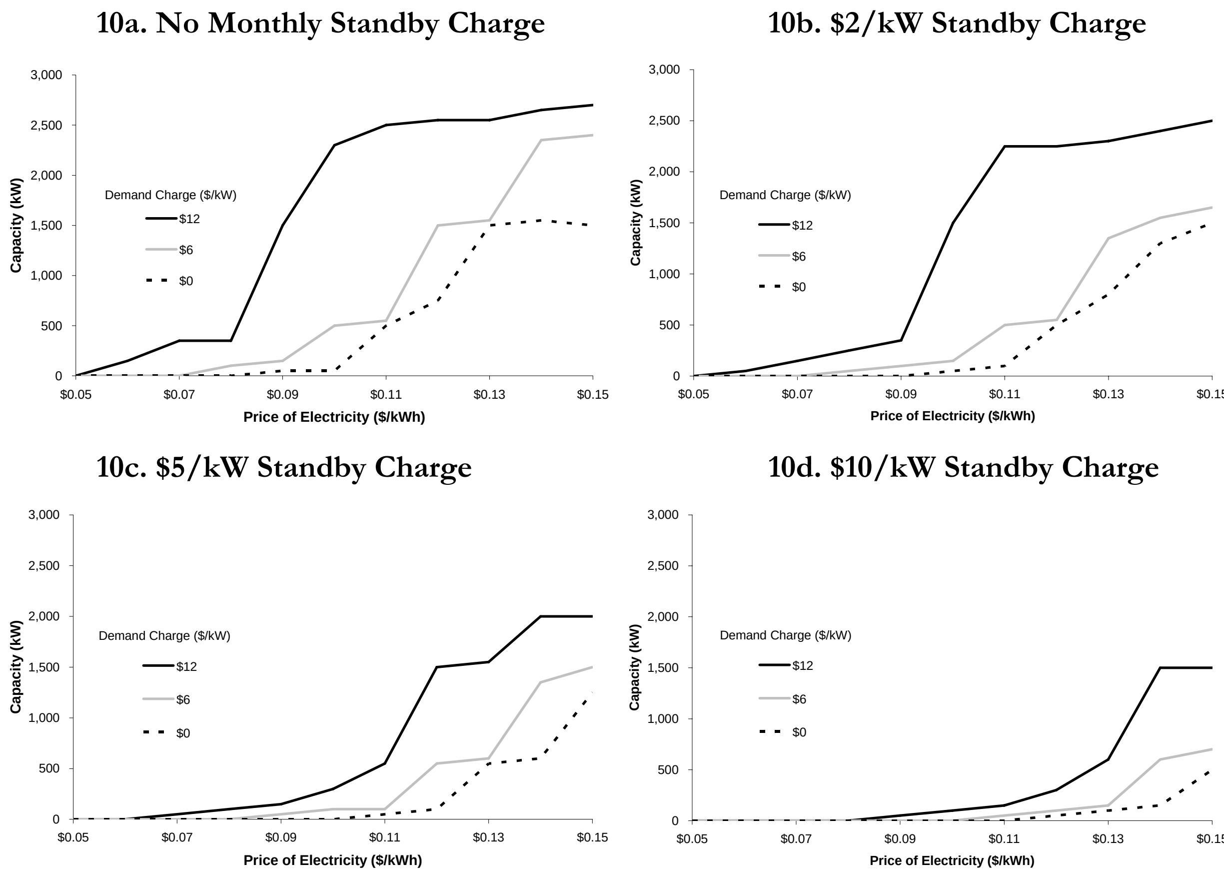
The difficulty associated with designing a fair and efficient tariff is well-stated by James Bonbright: “the problem of determining what surcharges will impose the least serious harm in the form of curtailments and distortions of use of service when the rates as a whole must yield total revenue requirements is perhaps the most complex and most difficult problem of modern rate theory" (Bonbright et al. 1988). This task is made more difficult when customer-generators are included in the problem because they act as both consumers of and competitors to public utilities, and they have higher price-elasticities for utility power than most other customers.

There may be cases in which the benefits of DERs fully offset the costs, but in general utilities will need to find an effective way to recover net standby costs. In this section, I compare the efficacy of different tariff components in achieving the dual goals of cost recovery and consumer rationing. Specifically, I examine how the three most common tariff components (consumption charges, demand charges, and standby charges) affect the long-term (capacity investment and installation) and short-term (operation) decision-making of micro-grid customers.

The results presented here are the output of the MCEEM. Hourly demand is assumed to be perfectly inelastic, so any changes in consumption reflect a shift by customer-generators from purchasing utility power to producing power on-site. The results shown here are for the Minneapolis high-rise building scenario. Unless otherwise discussed, data from other scenarios show similar trends (see Appendix C for complete results).

4.4.1 Capacity installation and robustness

Both the amount of installed capacity and the number and type of generators on a micro-grid can affect the net cost that a customer-generator imposes on the utility. More installed capacity gives a customer greater capability to provide ancillary services and interruptible loads to the utility. A system with more generators is less likely to experience simultaneous failures, and therefore requires less standby power from the utility.



Figures 10a-10d. The amount of on-site generation capacity that the customer-generator installs varies as a function of both utility consumption and demand charges.

Figures 10a through 10d demonstrate that the decision to install system capacity is very sensitive to both consumption and demand charges; if utilities choose to recover standby costs through either consumption or demand charges, customer-generators will install more capacity. On the contrary, if utilities recover costs through standby charges, customers install less capacity. As expected, customer responsiveness depends on the current state of utility prices.

Figures 11a – 11d. Number of generators installed by the micro-grid customer-generator as a function of utility standby, demand, and consumption charges. Increased demand and consumption charges result in more generators on the system. Increased standby charges result in fewer generators, and a less robust system.

Figures 11a through 11d demonstrate that a customer-generator's decision about the number of generators to install is somewhat sensitive to consumption charges and very sensitive to demand charges; in both cases, a customer will install a larger number of generators as price increases. Increased standby charges have the opposite effect, causing customers to reduce the number of generators on the system.

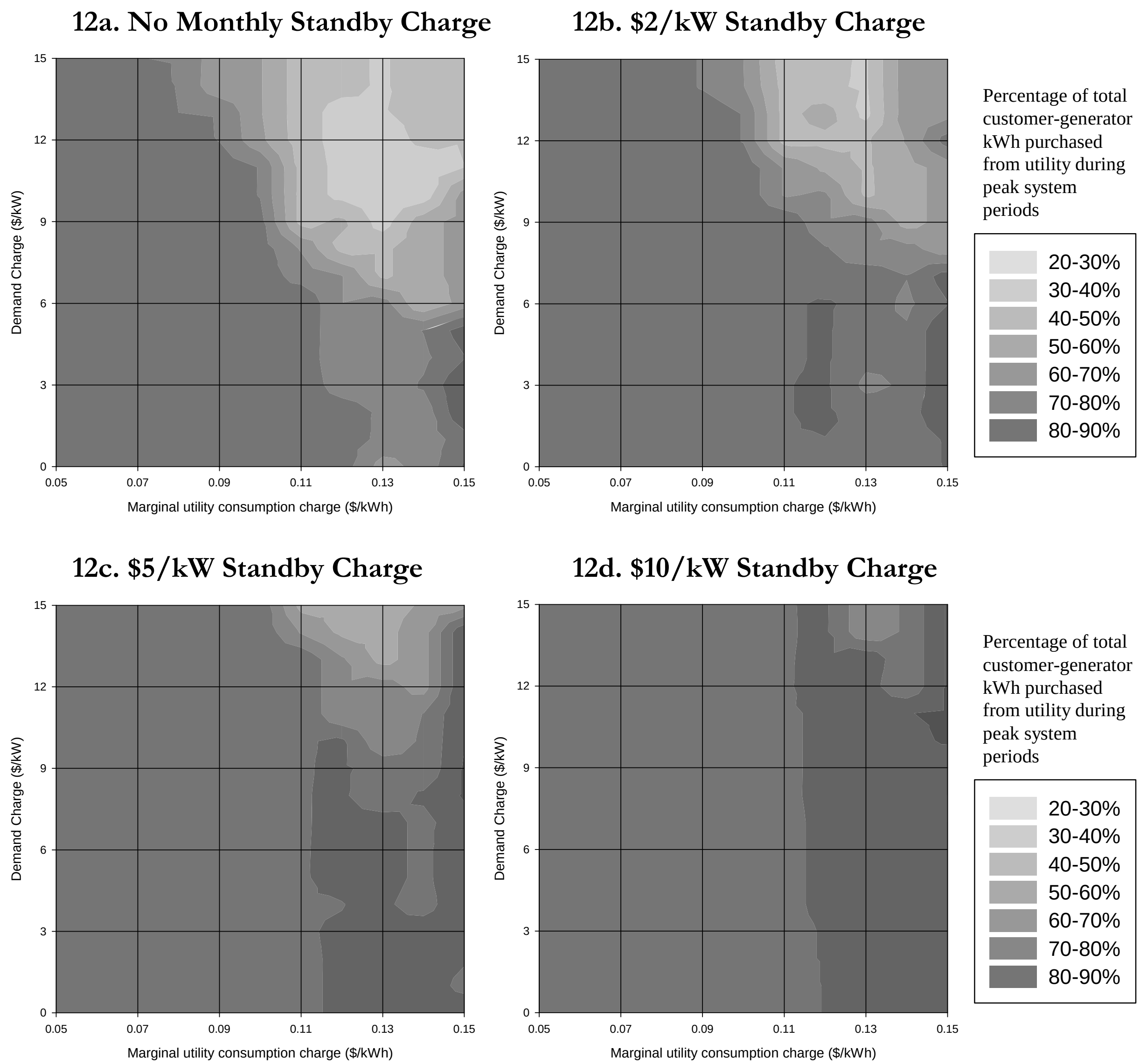
These trends correlate with the trend in installed capacity, but also reflect the avoidance strategies utilized by customer-generators in response to different tariff components. As marginal consumption rate increases, the customer has an incentive to install more capacity, and thus installs larger generators. As demand charges increase, the customer has an incentive not only to install more capacity but also to design the system to reduce the number of coincident outages, because demand charges are levied on the highest hour of peak demand and individual generator failures are guaranteed to occur. As a result, the customer installs *more* generators rather than just *larger* generators. Standby charges force the customer to only install capacity that will yield strong returns. Consequently, as standby charges increase, investment is only justified for generation capacity that can be operated with a high capacity factor (meeting overall or peak period baseload), so there the customer installs less capacity and fewer generators.

4.4.2 Peak vs. off-peak consumption from the utility

As discussed in section 3, faced with the right incentives, customer-generators will have flatter utility demand profiles than conventional customers.[42] Reduced peak period consumption is beneficial for the utility, and utilities and regulators should assure that tariffs are developed in a manner that encourages this.

Figures 12a through 12d demonstrate how consumption charges, demand charges, and standby charges affect customer-generator operation. Contours on each plot represent changes in the percentage of total annual power purchased by the customer-generator from the utility during peak periods. For comparison, a conventional non-generating customer of the same type consumes 78% of its electricity during peak periods.

[42] Utility demand profile refers to hourly purchases of utility electric power by the customer-generator. This is different from overall demand profile, which refers to the hourly demand for electric power by the customer-generator, regardless of the source (on-site or utility). For conventional customers that have no DERs, utility demand profile is the same as overall demand profile.



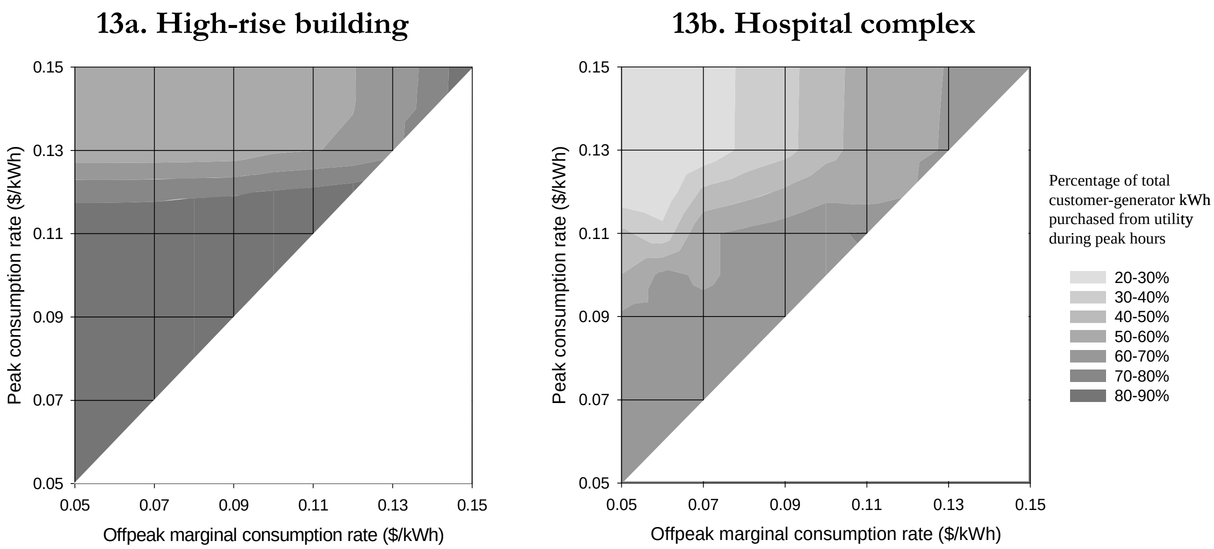
Figures 12a – 12d. Impact of utility rates (consumption, demand, and standby charges) on micro-grid consumption behavior. Contours represent the percentage of total annual power purchased by the customer-generator from the utility that occurs during peak periods.

For customer-generators, as consumption charges increase (x-axis), micro-grid operating costs becomes competitive with utility prices, and the customer-generator installs more capacity and operates the system more frequently (see figures 9b and 9c). However, there is no clear trend with respect to peak period consumption; in some cases peak consumption is reduced and in some cases it is increased. As demand charges increase (y-axis), the micro-grid customer consumes a smaller percentage of its power during peak periods. In some cases, this shift is dramatic, with peak period consumption dropping to 25% in the most extreme cases.

As standby charges increase, the customer-generator actually purchases a greater proportion of its power during peak periods. This last observation once again reflects the fact that standby charges drive customer-generators to install systems to meet baseload demand, resulting in higher demand peaks for the utility (and consequently, higher costs).

The results shown in Figures 12a suggest that increasing the consumption rate does not consistently drive peak demand down in the way that increasing demand charges does. One option for utilities is to vary rates with time-of-use (aptly referred to as time-of-use charges or TOU charges), so that consumption rates are higher during peak system periods than off-peak system periods.

The expectation was that high peak period rates would encourage customer-generators to produce more power on-site during peak hours, consequently flattening their demand profile from the utility. I used the MCEEM to test this hypothesis and found that it is supported by the results (see Figures 13a and 13b). TOU consumption charges are more effective than normal consumption charges at flattening the demand profile of customer-generators, but generally less effective than demand charges.



Figures 13a – 13b. Impact of time-of-use consumption charges on micro-grid consumption. Contours represent the percentage of total annual power purchased by the customer-generator from the utility that occurs during peak periods. Time-of-use consumption charges have a greater impact in the hospital complex scenario, which has a flatter overall demand profile.

One interesting observation is that TOU charges are more effective at flattening the demand profile of customers in the hospital complex scenario than the high-rise scenario (compare Figure 13a with Figure 13b). The indication here is that TOU charges are more effective for customers that already have relatively flat overall demand profiles.

4.4.3 Cost recovery without distortions to consumption

Most customer-generators will have much higher demand elasticities than conventional customers because their own generation acts as a competitor to the utility. High elasticities mean that optimal price-setting requires considerable insight into customer-generator demand curves. There is very little historical data on customer-generators, and demand curves are heavily influenced by technology developments for DERs as well as changing natural gas and grid electricity prices. Consequently, customer-generator demand curves can best be estimated using models like the MCEEM or Berkeley's DER-CAM (Marnay et al. 2001, Rubio et al. 2001). By understanding how customers respond to price changes, utilities and regulators can improve the efficacy of rate-setting and limit the extent to which unnecessary distortions in consumption occur.

In this study, overall demand has been taken to be perfectly inelastic and even inefficient price changes do not result in lost consumer surplus. In reality, adopting inefficient rate mechanisms to offset standby charges will result in lost consumer surplus. For this reason, it is important to understand how well various tariff components recover costs without distorting prices and affecting consumer surplus.

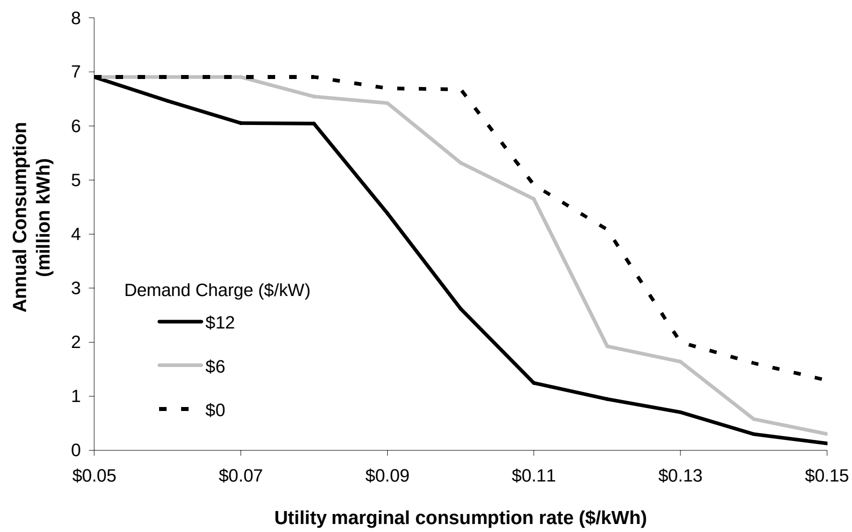


Figure 14. Micro-grid demand for utility electricity (kWh) as a function of utility consumption and demand charges. This plot reflects long-term, not short-term, installation and operational decisions by the customer-generator.

Figure 14 presents the long-term demand curve for utility power as a function of consumption and demand charges. As expected, increased rates result in greatly reduced consumption from the utility. This fits with earlier results (Figures 10a – 10d) showing increased customer-generator capacity installation resulting from higher utility rates. The secondary effect of these two trends is an increase in standby costs for the utility, but a decrease in the consumption over which standby costs can be recovered. Consequently, rates must be increased considerably in order to recover costs. Where utility prices are already high, revenue and standby costs may actually diverge as the utility raises prices further, making it impossible to fully recover costs.

Data presented earlier (Figure 10a) demonstrate that increased demand charges encourage customer-generators to install more capacity and to design and operate their micro-grid systems to minimize forced outages and consumption during peak periods. The result is that higher demand charges cause customer-generators to impose less risk (and associated standby cost) on the utility. Consequently, revenue standby costs converge without requiring prices to be distorted substantially.

Data presented in the previous section (Figures 10a through 10d) demonstrate that as standby charges are increased, the installed capacity of customer-generators will decrease but consumption during peak periods will increase. This trend means that utilities will need less standby capacity, but it also indicates that customers will be encouraged to design and operate the system in a manner that increases utility standby costs per kW installed. The result is a convergence of costs and revenues that is inefficient – better than consumption charges, but worse than demand charges. The exception here is customers who are likely to install a lot of local generation capacity regardless of utility demand charges – customers who place a very high value on reliability or operate in areas with poor service or very high utility prices. In these cases, increased standby charges do not affect customer behavior, so utility revenue and standby costs converge quickly.

4.5 Conclusions

Customer-generators will likely become a growing concern for utilities and regulators, as new DER technologies emerge and customer interest grows. Although some utilities have adopted a strategy of discriminatory rates in order to discourage any market growth for DERs, others recognize the value that customer-generators can provide and are interested in understanding how best to set rates so that they reflect the true costs and benefits that customer-generators yield. Clearly regulators should adopt this latter view in setting guidelines for, evaluating, and approving rates.

Two types of costs have been considered in this analysis – stranded costs and standby costs. Today, stranded costs do not seem to be a serious issue for most utilities, probably because much of the country is experiencing demand growth that is outpacing infrastructure growth. Standby costs are of greatest concern to utilities, and this is reflected in the language of tariffs and the mechanisms used to recover these costs. Two considerations are suggested for the estimation of standby costs: market prices for ancillary services like spinning reserves, and probabilistic estimations of customer-generators failures throughout the utility system. Customers-generators, especially those installing micro-grids, can design their system to reduce the probability of simultaneous failures, especially during peak periods. Utilities should recognize this and encourage such design choices through proper rate design.

Customer-generators can offer various types of benefits to the utility, three of which should be considered within the context of rate-setting: the provision of ancillary services; the provision of interruptible loads; and flattened utility electric demand profiles with fewer and smaller peaks. Ancillary services can be provided through bilateral contracts, but regulatory language should facilitate these transactions. Utilities should be required to offer lower-rate interruptible load tariffs to customer-generators. The benefits that the utility reaps from reduced peaks can and should be estimated – as is the case in "good customer" discounts for conventional customers – and tariffs for customer-generators should encourage and reward this good behavior.

In order to recover net costs, utilities have various tariff components to choose from. The effect of increased rates was modeled to determine how customers respond – in both their long-term (capacity installation) and short-term (operation) decision-making. Table 24 presents the trends associated with each method for cost recovery.

Table 24. Impact of Different Tariff Components on Customer-generators

Method for Cost Recovery	Trends for Customers-generators*			Most Appropriate
	Installed Capacity	DER System robustness	Demand Peaks	
Demand Charges	⬆	⬆	⬇	Most customers
TOU Consumption Charges	⬆	***No clear trend***	↓	Customers with very flat overall demand profiles
Consumption Charges	⬆	***No clear trend***	***No clear trend***	
Standby Charges	⬇	↓	↑	

* Trends presented represent comparison to no cost-recovery. Heavier arrows indicated a large increase or decrease, while lighter arrows indicate a comparatively small increase or decrease.

In most cases, demand charges are the most effective and efficient mechanism for cost-recovery. Demand charges provide customer-generators with an incentive to install more capacity and more generators, which makes the system more robust and less prone to failure. This design improvement, together with an incentive to operate on-site generation during peak periods results in lower standby costs for the utility.

Conventional consumption charges are generally less effective than demand charges at recovering costs in a way that also encourages "good behavior" by customer-generators. However, time-of-use consumption charges can be an effective mechanism for encouraging efficient consumption by the customer-generator while also recovering costs. In cases where the customer-generator has a very flat overall demand profile (i.e. consumes as much power during off-peak periods as it does during peak periods) and few demand peaks, demand charges are much less effective and time-of-use consumption charges make the most sense.

Standby charges are generally an ineffective tool for cost-recovery because they encourage customer-generators to operate on-site DERs in a way that increases the burden on the utility. Consequently, standby charges are only appropriate for customers that place a very high premium on reliability or those who operate in a region with very high rates. These customers have highly inelastic demand for capacity, and standby charges will not result in considerable consumption distortions or "bad behavior".

The details of tariff setting will depend on various factors, including the state of the local utility grid, and the policy goals of the state regulatory body. Utilities should be expected to evaluate both the costs and benefits that DERs will yield, as well as the relative impact that different cost-recovery mechanisms (e.g. demand charges, TOU or flat consumption charges, standby charges) will have on customer behavior.

Regulatory officials should require that feasibility studies and impact studies – which are standard during the interconnection of DERs with the system grid – include not only an assessment of the costs that a customer-generator will impose on the utility grid, but also an assessment of the benefits it will impart. The results of these studies should be used in aggregate to inform utility rate cases, and in individual situations to determine whether specific customers should be charged a fee or provided a refund for the cost of interconnection.

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Chapter 5. Innovation and Distributed Energy Resources: A Review of Relevant Literature

5.1 Introduction

One of the earliest motivations for my inquiry into electric power micro-grids was the supposition that a shift in the way that electric power is delivered to customers might help to transform the industry and promote the development and adoption of new and exciting innovations. In our 2003 guidance to state legislators, Granger Morgan and I posited that the growth of a micro-grid market "could unleash a wave of technological and business innovations similar to what occurred in telecommunications after the 1968 Carterphone Decision allowed customers to attach non-Bell devices…" (King and Morgan 2003). This statement had little empirical basis, but it was supported by Morgan's rich intuition about the nature of technological progress in the telecommunications industry and its relevance to the emerging area of distributed energy resources. This intuition, combined with the recognition that the electricity industry in its current form has been very sluggish in either producing or adopting new innovations, made this statement plausible.

In this chapter, I elaborate on the question of whether a market based on distributed energy resources (DERs) will promote more innovation than the current industry framework. The primary source of this evaluation will come from a review of academic literature in the fields of economics and management science. I hope this work brings the question of innovative activity into the fold of arguments about distributed energy resources, and motivates further, empirical research on this issue.

I will begin the discussion with an overview of the concept of innovation, with an explanation of the basic arguments for why firms do or do not innovate and the distinction between process and product innovations. Next, I will give a snapshot of innovative activity in the electricity industry and identify the most significant characteristics that distinguish DERs from conventional electricity supply. Finally, I will review the literature on the determinants of innovation and what this work suggests about the prospects for innovative activity in a DER market.

5.2 The Process of "Creative Destruction"

In his book Capitalism, Socialism and Democracy, Joseph Schumpeter coined the phrase "creative destruction", and made a major contribution to economics by considering the dynamic nature of markets and the role that innovation plays in firm survival. Creative destruction describes the evolution of markets in which successful firms continue to innovate and meet the new and changing needs of consumers, and unsuccessful firms fail and leave the marketplace. Schumpeter observed that "the fundamental impulse that sets and keeps the capitalist engine in motion comes from the new consumers' goods, the new methods of production or transportation, the new markets, the new forms of industrial organization that capitalist enterprise creates." (Schumpeter 1950, pg. 83).

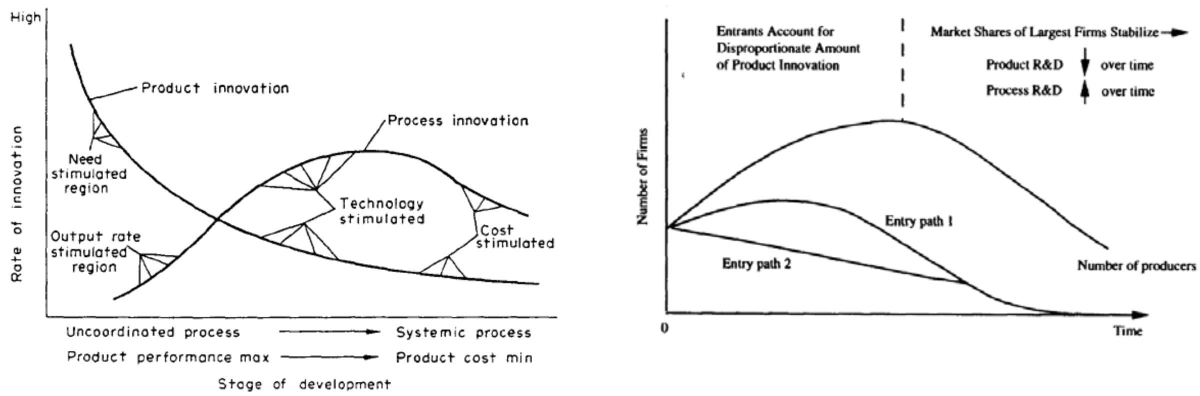
The motivation for individual firms depends on the market environment, but generally firms are driven to innovate for one of two reasons: increase the firm's price-cost margin, or increase market share (Utterback 1974). In a competitive market, firms that improve their production efficiency can either enjoy increased rents or set lower prices and capture a greater share of the market. Firms that increase the value of their product to consumers can either increase prices or market share. Even monopolistic firms have an incentive to innovate because process improvements can increase profits.

The distinction between process and product innovations is an important one, and has received much attention in the literature. Process innovation refers to an improvement that lowers the firm's average cost of production. Product innovation refers to an improvement that increases the value of the product to consumers. (Cohen and Klepper 1996). Product innovations can be further split into incremental or breakthrough innovations, with the latter doing more to increase market share and even create new markets (Tushman & Anderson 1986).

In Utterback and Abernathy early conceptual product lifecycle model, product and process innovations are linked and new markets go through stages of development. Early in the lifecycle, product innovations abound as firms try to understand what consumers want. As the market settles, product and process innovations are enabled by new technologies until a "dominant design" emerges that standardizes the product in the market (Figure 15a). Finally, once a dominant design is established, product innovations tail off and firms invest primarily in process innovations in order to cut costs and compete more effectively in a stable market (Utterback and Abernathy 1975).

This early product lifecycle model was followed by work on the motives for process vs. product R&D investment. Theoretical and empirical work revealed that early in the product lifecycle, the number of firms competing for market share grows and these firms invest in product R&D to differentiate themselves (Figure 15b).

15a. **15b.**



Figures 15a and 15b.[43] Product lifecycle models. Utterback and Abernathy (Figure 15a) suggest that as a market develops, innovative activity shifts from product to process, with both eventually tailing off. Klepper (Figure 15b) suggests that as a competitive market develops, the number of firms competing for market share increases until market leaders emerge, at which point the industry experiences a "shakeout" and the number of firms decreases.

Eventually, the industry experiences a "shakeout", in which a few firms establish themselves as market leaders and many of the remaining firms exit the market (Klepper and Simons 2005). At that point, the market leaders have both the capital and market security to invest more heavily in process innovations, and they have more to gain from process improvements. Simultaneously, they have less of an incentive to invest in product innovations because they are heavily vested (both in brand and infrastructure) in a dominant product (Klepper 1996). Remaining product innovations tend to come from new entry firms serving a niche (von Hippel 1988).

The product lifecycle model is an abstraction and oversimplification of real-world markets. Industries will often encounter technological discontinuities that can interrupt and/or re-start the product lifecycle (Tushman and Anderson 1986). Recent work also shows that in certain industries

[43] Figure 15a copied directly from Utterback and Abernathy 1975, pg. 645. Figure 15b copied directly from Klepper 1996, pg. 564.

(e.g. electronics, computing) product innovation continues indefinitely in response to heterogeneity and/or shifting consumer values (Adner and Levinthal 2001).

The ability of firms to appropriate the benefits of new innovations also plays a role in how R&D investment is made. Product innovations can have value for both market participants (small and large) and vendors because they can be sold in a "disembodied form" through patents and licensing. Process innovations, on the other hand, are rarely sold in disembodied form because process patents are typically ineffective in preventing duplication, and process innovations require more familiarity with the manufacturing processes of individual firms, making them less generalizeable across multiple firms and hence less valuable (Levin, et al. 1987). This means that process innovations are likely to only occur in-house, and predominantly by firms with a large market share (Cohen and Klepper 1996).

5.3 Innovation in the Electricity Industry

The electricity industry has long suffered from underinvestment in research and development, and low rates of innovation. The reasons for this are varied, but the results are clear. In 1994, utilities spent an average of 0.3 percent of their revenue on R&D, and a 1998 report reveals that this number actually declined as the industry approached restructuring (GAO 1996, GAO 1998). Since then the level of investment has remained low. This rate of investment is as low as any major industrial sector in America, ranking well behind the national average (Table 25). Most of the energy R&D investment in the U.S. comes from national and state governments, but this still amounts to the equivalent of less than 1% of industry revenues.

Table 25. Comparison of R&D Investment for Select Industries		
	Avg. R&D / sales ratio (1994-1996)	Avg. R&D / sales ratio (1998-2000)
Biotechnology corporations	32.6 %	34.3 %
Medical substances and devices	11.3 %	12.3 %
Information & electronics manufacture	5.8 %	7.4 %
Aerospace	3.7 %	3.3 %
Chemical manufacture	3.2 %	3.6 %
Engine, turbine manufacturing	3.2 %	3.5 %
Electric power utilities	0.3 %	< 0.3 %
Wholesale and retail, transport and warehousing	0.2 %	0.3 %
Source: Data on utility R&D investment comes from the GAO (GAO 1996). All other data provided by the U.S. Technology Administration statistics on U.S. Corporate R&D Investment. Available on-line at http://www.technology.gov/reports/CorpR&D_Inv/CorpR&D_Lists_1994-2000.htm.		

There have been innovations adopted by the industry, such as combustion turbines (derived from aerospace applications) and computer-based SCADA, but they have had only modest impacts on the nature and operation of the industry.

One common measure of an industry's performance is the efficiency with which inputs are converted to outputs. In the case of central station electric power, this measure has limited diagnostic power because of the large and long-lived nature of capital investments. That said, the generating efficiency of centralized plants has seen little improvement over the past 50 years (Figure 16), and non-fuel expenses per MW have actually increased in the last 20 years (Figure 17).

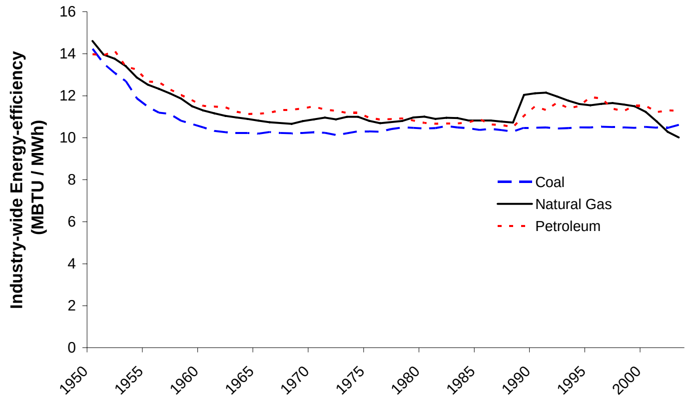


Figure 16. Generating Efficiency of the electricity industry from 1950 to 2000. The efficiency of centralized generation has remained steady for 50 years, showing almost no improvement.[44]

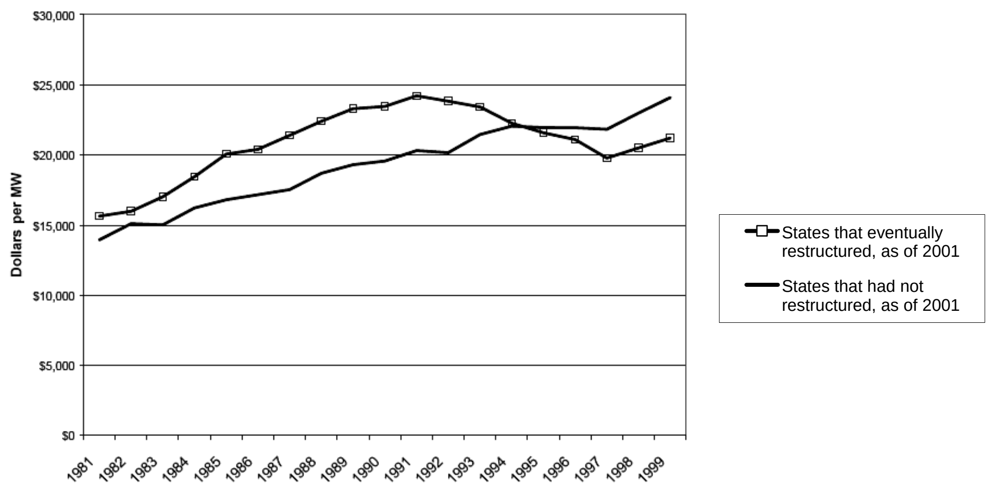
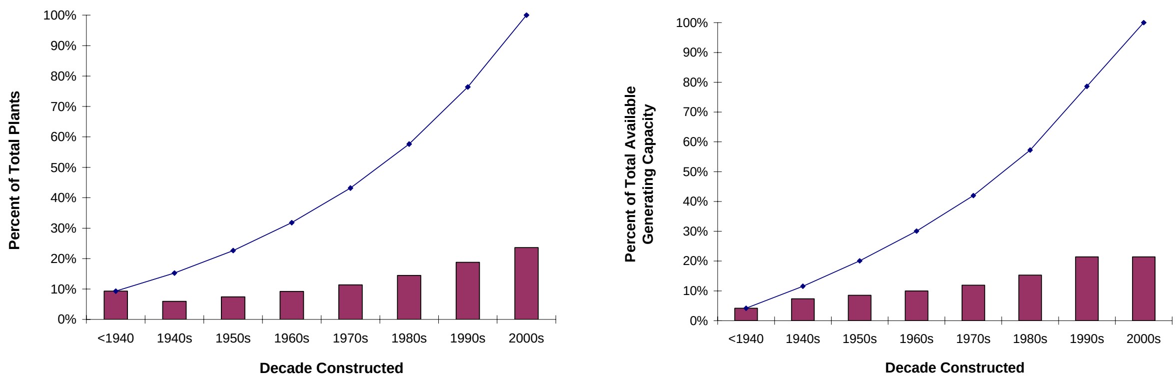


Figure 17. Average non-fuel expenses per MM, grouped by state according to whether restructuring eventually occurred, as of 2001. In the past 20 years, average non-fuel expenses have increased, with only a temporary dip in restructuring states in the past decade. This figure is copied from Wolfram 2003, pg. 30, and the original data source is FERC Form 1 utility data.

Stagnation, and the impact of long-lived fully amortized capital, can be seen in the vintage of the electric generating infrastructure in the U.S. (figures 18a and 18b). Roughly 43% of the power plants in the U.S. were built before 1980, 32% were built before 1970, and 23% were built before 1960. This trend is partly reflective of the high cost and risk associated with building new power plants, but slow turnover also reflects low rates of innovation and/or adoption in the industry.

[44] Data compiled from the US Department of Energy EIA Annual Energy Review, Chapter 8, using aggregate energy (MBTU) as the input and electricity production (megawatt-hours) as the output.



Figures 18a and 18b. Vintage of centralized power plants and generating capacity in the US, as of 2004. The old vintage of much of the electricity industry reflects very low rates of turnover. [45]

There are other areas outside of generation in which there have been greater opportunities for investment which have also seen very limited innovation. These include the adoption of Flexible AC Transmission Systems technology to improve the use of existing transmission stock, distribution automation to improve performance and reliability, and innovation in customer interface such as time-of-day and smart meters and advanced load control and demand-side management.

5.4 The Differences Between DERs and Conventional Supply

DERs differ from centralized supply in both the market structure within which firms compete and innovate, and the physical characteristics associated with the generating resources.

I argue that the market structure for DERs differs substantially from that of centralized supply in two basic ways: 1) a market for distributed energy resources can more easily offer product differentiation, and 2) a market for distributed energy resources is potentially more competitive. Centralized electricity supply is essentially uniform in its product – all customers on the system pay for and generally receive reliable AC electric power of consistent quality. Any variation in power

[45] Data compiled from the U.S. Energy Information Administration 2004 Annual Electric Generator Report. This dataset does not include plants that were designated as retired or categorized as distributed generation plants.

quality and reliability is usually the result of imperfect supply, not product differentiation.[46] A market based on distributed energy resources can offer substantial product differentiation, because energy products and services can be customized to the needs of individual customers. Customers actually have very little value for electricity – they value the goods and services that rely on electric power. Firms in a DER market are better able to tailor their products to the needs of individual customers, and the consequent market differentiation drives product innovation that is basically impossible in a centralized market. This will be discussed further later in this chapter.

In many parts of the U.S., electricity is still generated and supplied by vertically integrated monopolies. In areas where there has been progress to create competitive markets, electricity distribution and retail interaction with customers is still controlled by regulated monopolies. The only sector of the industry in which competition has grown is power generation, and even this sector suffers from various barriers to competitive entry, particularly limited access to capital, economies of scale, fixed costs and sunk costs,[47] and political and regulatory obstacles that favor the incumbent (See Karakaya and Stahl 1989 for a review of literature on barriers to market entry; Bain 1956 and Kahn 1971 for further discussion of economies of scale; Bain 1956 for further discussion of access to capital as an entry barrier; see Spence 1977, and Baumol and Willig 1981 for further discussion of sunk costs as entry barriers).

The link between competition and innovation has been the subject of considerable investigation, inspired by Schumpeter's early hypothesis that the prospect (and temporary holding) of

[46] The lone exception here is interruptible service contracts offered to customers that are willing to allow the utility to cut service during peak hours in exchange for lower rates.
[47] The argument for fixed costs and sunk costs as a barrier to entry is that in a constrained market, incumbents can invest heavily in capacity to deter entry. Sunk costs in excess capacity are a signal to potential entrants that entry will drive prices down to near-zero profit, and the prospect of low profits is an effective deterrent to new entry.

monopolistic power is more likely to encourage R&D than the guarantee of a competitive environment (Schumpeter 1950). Early studies suggested that monopolistic or oligopolistic firms are more likely to invest in R&D, but later work has shown that when economic models account for factors such as firm size and industry-specific effects such as "technological opportunity",[48] market concentration becomes negatively correlated with innovative activity (see Kamien and Schwartz 1975 for a review of literature up to the mid-seventies; see Geroski 1990 for a comparison of empirical models with and without industry-specific effects; see Knott and Posen 2003 for more recent support). Theoretical models similarly show that an increase in the number of firms will increase overall R&D investment within an industry, and increase the probability and reduce the time it takes for new innovations to be introduced, even if it reduces R&D investment and profitability by individual firms (Loury 1979).

Distributed generation and distributed energy resources are distinguished from centralized generation by three primary physical (rather than market) characteristics.

1) Smaller in size - The average size of a power plant in the US is over 60 MW, and 75% of central plants are over 100 MW in capacity, [49] whereas distributed generators generally range from 1 kW to 5 MW. This smaller size also means that, although DG units are typically more expensive per kW, individual DG installations require much less capital than centralized installations.
2) Dispersed – Distributed energy resources are, by definition, located near consumers, and they serve individual or small groups of customers. Provision of electricity, as well as

[48] Technological opportunity is best described as a statistical "catch-all" that captures how well (or poorly) different industries lend themselves to innovative activity.
[49] The US Department of Energy, Energy Information Administration. Annual Electric Generator Report, Form EIA-860 Database. Available on-line at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

associated energy products and services, can be differentiated for each customer based on their needs or values.

3) Modular – Most distributed generation resources are small-scale, off-the-shelf technologies that can be bought and installed in pieces. Customers can design their systems with a mix of different technologies, and easily scale up by adding more generators as demand increases. This modularity, combined with assembly-line style production has increasingly led to standardization in the interface, controls, and interconnection of components.

In the following sections, I discuss what the literature says about these characteristics, and why markets built on technologies with these qualities are likely to facilitate higher levels of innovation than that found in the current industry.

5.4.1 The importance of size

To date, there has been no empirical or theoretical demonstration of a strong relationship between product size and innovative activity. However, in the case of electricity supply, for a given level of demand, smaller resources do allow the possibility of more players as well as lower capital barriers to entry and a greater number of sales. This has implications for the learning curves, rates of process innovation, and levels of competition within the industry.

Early work by Joseph Bain identified what he called "absolute capital requirements" as potential barriers to market entry. Bain demonstrated that certain industries required a very high capital investment for entry, and these industries also showed much higher levels of profit. Bain intuited that higher profits suggested lower levels of competition, but he also recognized that other factors were at work, and he did not quantify how much of a deterrent capital requirements pose to potential entrants (Bain 1956).

Bain's work did inspire later, more quantitative inquiries. Early econometric studies demonstrated that capital requirements do provide a barrier to entry, but these studies were oversimplified, looking at small groups of industries and considering only a few variables in their models (Mansfield 1962; Mann 1966). Later, more thorough econometric studies continued to support Bain's conclusion (Orr 1974, Harrigan 1981). Once industry-specific fixed effects were incorporated into econometric models, capital intensity was revealed to be strongly associated with "technological opportunity", although not necessarily causal (Geroski 1990). Geroski's model suggests that high technological opportunity is associated not only with smaller capital intensity, but also larger market size, higher market concentration, higher firm entry and exit, and higher profitability, and that technological opportunity accounts for more than 60% of the variation in innovative activity across industries.

A survey of corporate executives supports the claim that capital requirements are a barrier to new entry. Respondents indicated that capital requirements are a very significant consideration – second only to cost advantages – when deciding whether to enter a new market. Executives expressed this concern regardless of whether the market was new or mature, for industrial or consumer goods. (Karakaya and Stahl 1989)

The effectiveness of capital requirements as a barrier to entry was cited in the 1969 anti-trust case against IBM, as reported by William Fruhan. In that case, competitor General Electric claimed that it would have to invest more than $135 million per year over 5 years in order to achieve the minimal market share necessary to just break even. Due to economies of scale in the industry, anything less would result in a market share of under 10%, and a net loss for GE. For context, this level of investment was equal to GE's discretionary cash flow at the time and represented a sufficient barrier to entry that GE soon afterwards sold its computer business to Honeywell (Fruhan 1979, cited in Baldwin and Clark 2000). The case against IBM was later thrown out, but IBM did maintain a stranglehold on the mainframe market for some time. Successful competition did not thrive in the computing industry until firms began to compete in sub-markets – a phenomenon that directly resulted from the modular design of IBM's System/360. This will be discussed further later in the chapter.

As discussed earlier, the relationship between competition and innovative activity suggests that industries with smaller capital requirements will experience more innovative activity. Although capital requirements will still exist in a DER market, they should pose a smaller barrier to entry than in the current industry structure. Not only are individual units less expensive to manufacture (per unit), but the market share that a entrant firm needs to capture is much less because DERs exhibit less severe economies of scale than centralized generation, and the market is more easily differentiated and segmented into sub-markets.

The small size of distributed energy resources may also impact the ability of DER firms to learn and innovate. If the supply structure for electric power does not influence demand, one can expect that a market met by DERs will necessarily require greater sales of generation resources than one met by centralized generation. For example, a market that requires 250 MW of capacity will only need one or two large central generators, whereas the same market may require between 10 and 250 distributed generators. This observation, together with the fact that many central power plants are not highly standardized, suggests that, ceteris paribus, firms in a DER market will experience greater rates of output production, and consequently more learning and process innovations.

The literature on learning curves begins with one premise, stated simply in the opening line of Argote and Epple's critical work: "as organizations produce more of a product, the unit cost of production typically decreases at a decreasing rate" (Argote and Epple 1999). This trend has been demonstrated in various industries, and learning can extend far beyond unit cost reduction to include improvements in product quality and process effectiveness. A learning curve is a long-term representation of incremental process innovations, and learning seems to occur in almost every kind of manufacturing. There is no reason to expect that the distributed generation market would be an exception.

5.4.2 Dispersed market structure

Unlike centralized power supply, dispersed or distributed supply allows both greater interaction with and customization for individual consumers. This proximity to customers may result in an unprecedented level of product differentiation for energy services, as well as increased and improved learning from customers that leads to valuable product innovations.

There are several ways to define and think about product differentiation. In much of the literature on monopolistic behavior, differentiation is seen as a way to segment markets and set discriminatory prices that maximize profits from each segment. In the literature on competition, product differentiation enables leaders in a homogenous market to distinguish their product through name recognition and brand loyalty, thus giving them the ability to set their own prices and prevent entry by competitors.

Here, I use the term product differentiation to refer to the ability of competitive firms to cater to market niches and take advantage of heterogeneous customer demand to compete for market share. In this context, the term "product" actually refers more generally to a category or family of products. By broadening the conventional energy product – kilowatt-hours – to a family of products that includes reliability, power quality, demand management, heating and/or cooling, environmental quality, etc., firms will be able to compete across a broader, more competitive market through the introduction of new energy products and services.

Research on technological discontinuities suggests that some industries go through a re-birth, in which product innovations improve upon and displace previous products, and destroy the competence of incumbent firms, thus prompting new firm entry and exit and starting the product lifecycle over again until a new dominant design emerges (Tushman and Anderson 1986). The cause of product innovations that leads to technological discontinuities is unclear, but it seems to be a combination of what have been called "technology-push" and "demand-pull" forces (see Mowery and Rosenberg 1979 for a critical review of work on the relationship between market demand and innovation; see Dosi 1982 for a comparison of technology-push and demand-pull). Although a simplified "demand-pull" paradigm suffers from various criticisms, it is clear that variation in customer demand is a critical necessity for innovative activity.[50]

[50] The primary criticism in both the Mowery and Rosenberg review and the Dosi article is that the demand-pull paradigm is insufficient on its own. This criticism falls within the context of a larger debate over science R&D funding, and these authors argued that basic R&D – "technology push" – is equally as important as market demand factors. One of Dosi's criticisms of the demand-pull theory is that it cannot account for why, given a range of potential consumer needs that is "nearly infinite", certain innovations result. Implicit in his criticism is the assertion that any innovative activity hinges on a variety of consumer needs and product differentiability.

Recent work by Adner and Levinthal focuses on the importance of demand heterogeneity in the product lifecycle. The authors model dynamic markets in which simulated customers have varying utilities for different product improvements. They find that in competitive environments, customer preference plays an important role in the choice between product and process innovations early in the lifecycle. They also find that firms continue to improve product performance to earn market share even after reaching a dominant design and price stability. The technology lifecycles for personal computers and video cassette recorders are provided as empirical support (Adner and Levinthal 2001). Further empirical support for this paradigm can be seen in the typesetter industry (Tripsas 1996). Tripsas suggests that in some cases, such as the typesetter industry, demand heterogeneity can increase over time as consumers go through “preference discontinuities”, marked by shifts in consumer preferences (Tripsas 2001).

If heterogeneous demand does lead to increased product innovation, there is also reason to believe that the dispersed nature of DERs will lead to more effective, useful products that meet the needs of consumers. Although most of the literature focus has been on the determinants of R&D spending and/or innovative activity in different industries by different types of firms, there has also been a good deal of work trying to understand the determinants of successful R&D spending, i.e. what makes for a successful new product innovation?

One of the most significant and effective studies on this subject was project SAPPHO, which was a comparative, empirical study of product successes and failures. In the study, 43 pairs of product innovations (22 in chemical processes and 21 in scientific instruments) were compared, and each pair consisted of one failure and one success. Innovations were categorized by their commercial success – whether the product attained market penetration – not by their technical success (e.g.

whether they worked). Pairs of innovations were chosen because each innovation within the pair served the same market, not necessarily because they were similar technologies.

Each pair of innovations was compared using 122 different measures – questions that were used to tease out the most significant determinants of success. These measures were evaluated for statistical significance and then grouped into 5 different factors. The SAPPHO study concluded that the most significant determinant of success is "user needs understood" (Rothwell et al. 1974, Freeman 1982). This conclusion is supported by similar studies conducted on various industries in various countries (Zirger and Maidique 1990).

If we believe that a firm can learn more about customer needs through regular interaction, it is likely that a DER market will not only yield more product innovations, but *better, more valuable, more highly adopted* product innovations. In fact, an energy service market based on DERs may ultimately provide a valuable solution to the famed energy-efficiency paradox – that energy-saving products and services are under-adopted despite the seemingly obvious financial benefits (Shama 1983). The argument that dispersed sites can improve product development is supported by the experience of the typesetter industry (Tripsas 2003)[51], and work in the field of economic geography suggests that proximity to market can improve a firm's ability to create useful products, but the significance of proximity is unclear – especially in an age when information flows so cheaply and easily.

[51] Work by Tripsas actually shows that dispersed research activity has benefits, not necessarily dispersed sales. However, some of the arguments Tripsas presents – that dispersed sites facilitate learning from local experts and consumers and encourage variety and diversity, which translates into improved innovative activity – are very relevant here.

5.4.3 Modular product architectures

Sanchez and Mahoney (1996) present an articulate description of modularity, which I will use throughout this discussion:

> A *modular product architecture* is a special form of product design that uses standardized interfaces between components to create a *flexible* product architecture. In modular product design, the standardized interfaces between components are specified to allow for a *range of variations* in components to be substituted into a product architecture.

Inter-firm modularity is often the most recognizeable, but modular forms are also utilized within firms in order to increase flexibility and potential product offerings. Inter-firm modularity is usually facilitated through the creation of universal, standardized interfaces by either a dominant firm or an external organization, such as those accredited by the American National Standards Institute. In the case of DERs, the Institute of Electrical and Electronics Engineers has been the organization responsible for creating a set of interconnection standards that are safe and reliable (IEEE 2003).

The ability to make substitutions for (or additions/removal of) individual components without disrupting the effectiveness of a product creates considerable value and flexibility. In the short-term, this capability enables users to make changes to a product with less risk and cost. In the long-term, it facilitates competition by taking what would otherwise be a market for one single, integrated product and fractioning it into lots of sub-markets, each of which is open and dynamic.

In their book Design Rules, Baldwin and Clark explore the concept of modular design more fully, and the impact that modularity has had on the computer industry. The authors describe the difficulty and risk associated with creating a modular artifact (i.e. product or system), but also explain how a modular design can facilitate the development and growth of a complex system with only some basic universal design rules as constraints. Baldwin and Clark chronicle the risk, and ultimate success, that IBM experienced in the design and introduction of the System/360 family of compatible computers introduced in 1964. The design of the System/360 was revolutionary because it placed a premium on compatibility within and across machines and components. (Baldwin and Clark, 2000).

The immediate impact of the System/360 was huge profits for IBM, and a steep decline in competition. However, the design of the System/360 enabled firms to become more active and competitive within emerging sub-markets for individual modules (e.g. chips, software, etc.). Eventually, thousands of firms emerged in sixteen different industry subcategories. Baldwin and Clark assert that this growth is generalizeable to all markets with modular products: “modularization multiplies design options and at the same time disperses them so that they can be ‘picked up’ by many people, without the permission of any central architect or planner. The pursuit of valuable options by many decentralized actors in turn accelerates the rate of change of the system as a whole.” (Baldwin and Clark 2000, pg. 223)

Having a modular product design may also have significant implications for the organizational structure of the firm. Sanchez and Mahoney argue that firms offering modular products are more capable of designing their organization to also be modular. Organizational modularity allows a firm to quickly identify market shifts in consumer demand, technology development, competitive balance, etc., and react with new innovations or strategies (Sanchez and Mahoney 1996).

The relationship between product form and organizational design is observed in the case of IBM - the new modular design of the System/360 enabled IBM to split up its R&D activities into groups to work on separate modules. This enabled IBM to better utilize its people and focus R&D dollars on the modules that had the most promise for commercial value. (Baldwin and Clark 2000).

Distributed energy resources are not perfectly modular, and centralized power supply is not without some modularity. However, DERs do have more of the qualities discussed by Baldwin and Clark. Schilling's work on modularity also reveals important links between market structure and inter-firm product modularity. She proposes that markets that are competitive, rely on diverse technological options, and include heterogeneous consumer demands are more likely to adopt modular product designs (Schilling 2000). If this is true, the qualities that have already been discussed which distinguish DERs from centralized electricity supply will continue to reinforce the degree to which DER products are modular.

If DER technologies continue to mature and the market is allowed to flourish, one can envision a market with components that are fairly easily installed and/or removed, each with different qualities and value to the customer, and some overarching design rules that dictate interface and interconnection with both the utility grid and the consumer HVAC and electric systems, and within customer micro-grids. Firms will have the opportunity to compete within sub-markets for generation, energy storage, power quality devices, demand management systems, and system controls. Increased competition and flexibility will not only drive innovation among firms, but also facilitate the adoption of new ideas and improvements into existing products and markets.

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Appendix A: DER Technology Characteristics

The technologies used in this analysis include internal combustion engines, gas turbines, micro-turbines and fuel cells. The figures in this appendix represent the modeling assumptions used in the micro-grid customer engineering-economic model (MCEEM), as discussed in Chapter 2. Data were gathered for the DOE BCHP Screening Tool, released in 2003 by Oak Ridge National Labs. Engine data were provided by Caterpillar, Cummins, Elliot, Kohler[52] and Wartsila. Micro-turbine data were provided by Elliot Energy, Honeywell, Capstone, and Allison. Turbine data were provided by GE and Solar. Fuel cell data were provided by Solar, Z-tek, and Siemens-Westinghouse. In some cases, fuel cell data are based on expected or emerging systems that were not commercially available as of 2003. For this reason, and cost considerations, fuel cells were not utilized in the MCEEM.

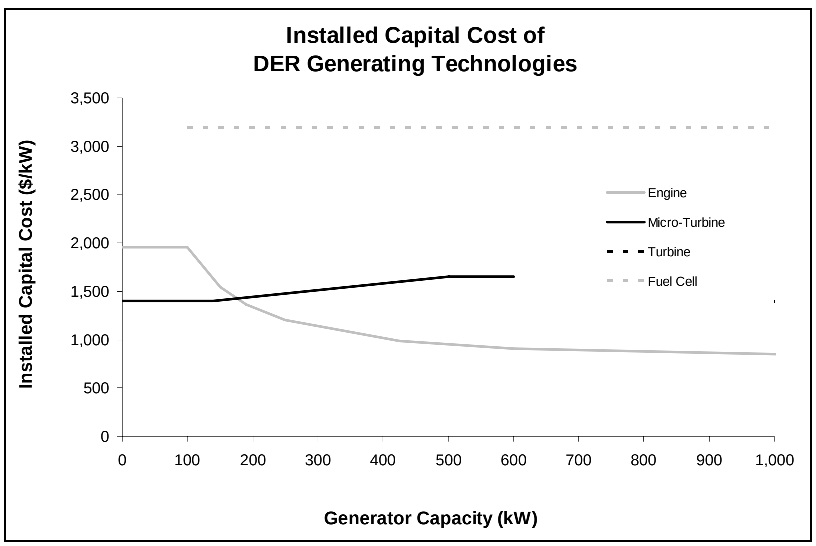


Figure A1. Installed cost of generators as a function of rated capacity. Engines and turbines experience economies of scale, but current micro-turbines and fuel cells do not.

[52] Kohler operational data was gathered independently from the company and was not included in the BCHP Screening Tool.

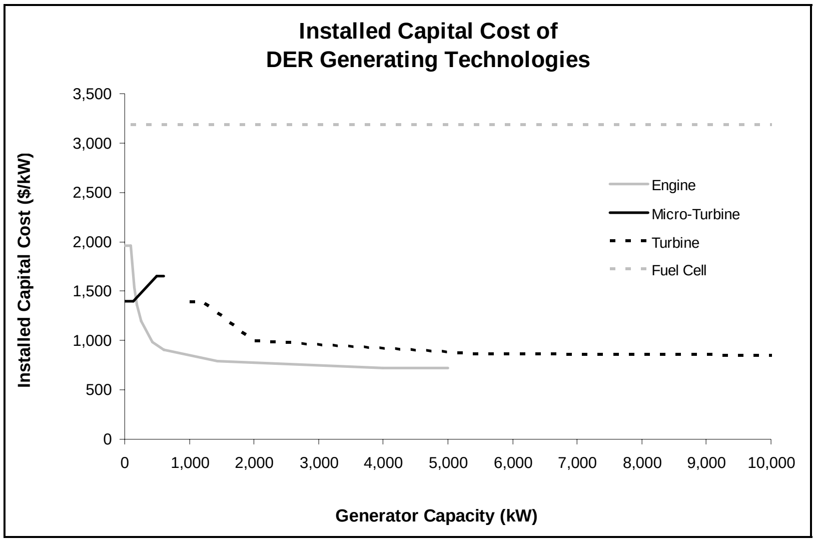


Figure A2. Installed cost of generators as a function of rated capacity. Engines and turbines experience economies of scale, but current micro-turbines and fuel cells do not.

Figures A-1 and A-2 show the cost of installed generators as a function of size (Figure A-2 is an overlap of Figure A-1). These curves show that turbines are not suitable for small projects (the discontinuity means that generators are unavailable at these sizes). They also show that engines and turbines see a dramatic reduction in average installed costs ($/kW) for larger generators. Remarkably, the micro-turbines that are commercially available right now see an increase in cost as size increases. It is likely that this will change in time as the technology is further developed.

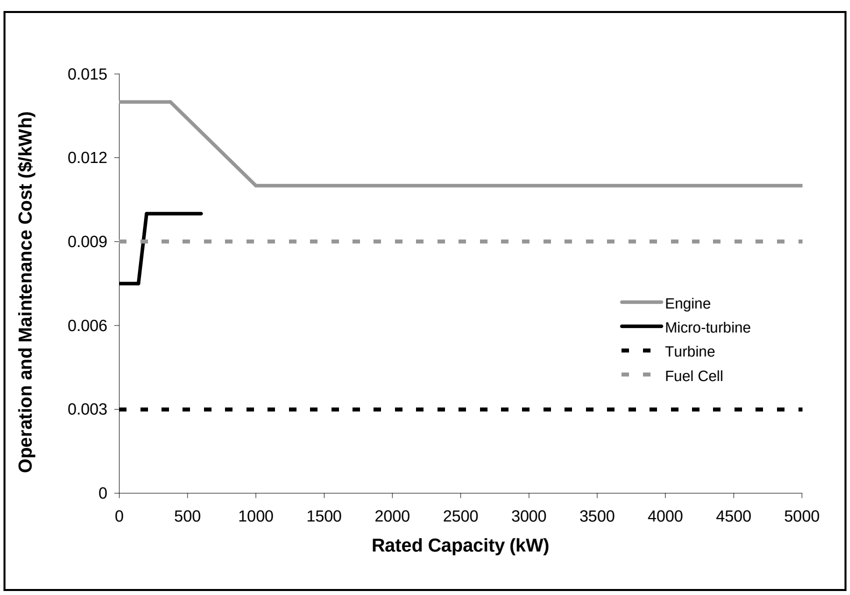


Figure A3. Operation & maintenance cost as a function of rated capacity for each generator type.

Figure A-3 presents the operation and maintenance cost for generators as a function of installed rated capacity. O&M costs are lowest for turbines and highest for engines. These cost estimates are averaged over the life of the equipment.

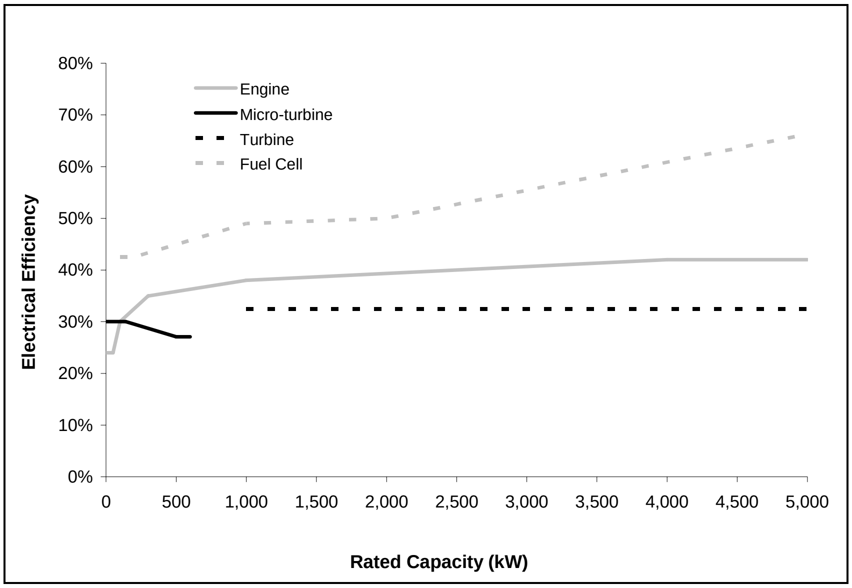


Figure A-4. Rated electrical efficiency for different generator types as a function of rated capacity.

Figure A-4 presents the rated efficiency for generators as a function of installed rated capacity. Engines exhibit economies of scale, with efficiency increasing with size, especially at small sizes. Fuel cells are the most efficient generators, and see considerable economies of scale. Micro-turbines actually exhibit diseconomies of scale. These curves are interpolated from data provided by manufacturers, resulting in discontinuities in the curves. Micro-grids are limited to 600 kW, and turbines are not produced below 1,000 kW.

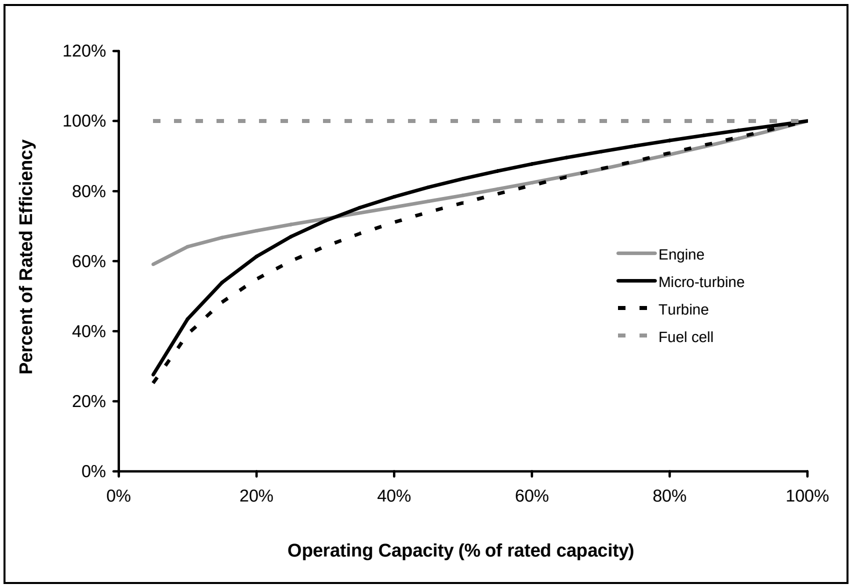


Figure A-5. Partial-load efficiency curves. When an engine, micro-turbine, or turbine is operated at less than its rated capacity, it operates with less efficiency. Fuel cells do not exhibit this behavior. The partial load efficiency curves vary by technology, and are defined by quadratic functions.

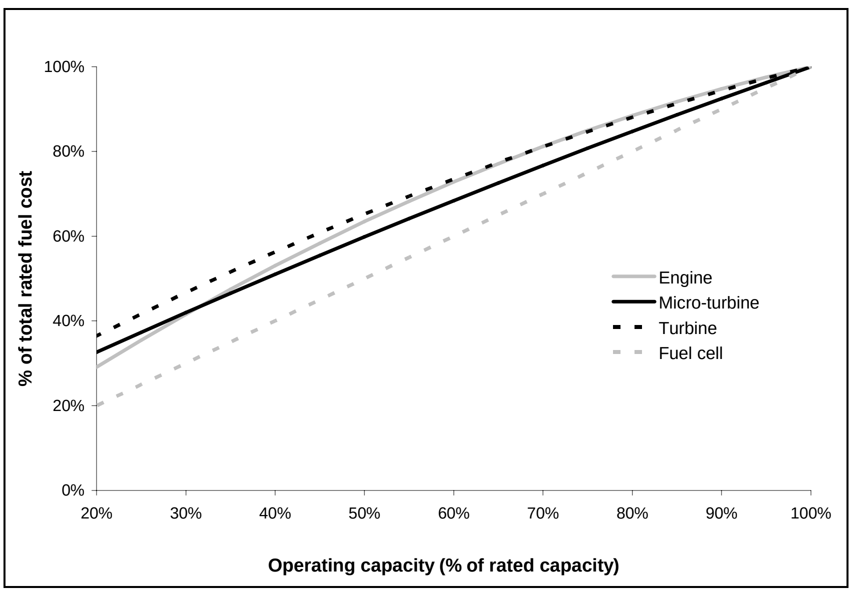


Figure A-6. Fuel cost curves. When an engine, micro-turbine, or turbine is operated at less than rated capacity, it operates less efficiently and consumes proportionately more fuel. The fuel cost curves vary for each technology, and are defined by quadratic functions.

Figure A-5 presents partial load efficiency curves for each type of distributed generators. Figure A-6 presents fuel cost curves for generators at operated at partial capacity, and is simply a different way of presenting the data in Figure A-5. Both figures show how well generators operate below rated capacity. For example, when a generator is operated at 100% of its rated capacity, it consumes 100% of the rated fuel use, but when operated at 50% of rated capacity, only the fuel cell will use 50% of its rated fuel use; the micro-turbine will use 60% of the rated fuel; the engine will use 63%; and the turbine will use 65%. This can be important for micro-grids with generators that will be used to follow load and often operate at partial capacity.

Appendix B. Survey of State Regulatory Officials

In September and October 2004, nearly 250 members or senior staff representing every state Public Utilities Commission or Public Service Board were contacted by e-mail or phone requesting that they participate in an on-line survey. Follow-up contacts were made in states where no one had yet agreed to participate. The survey was reviewed and approved by Carnegie Mellon University's Institutional Review Board prior to the release of the survey. The survey period lasted nearly 5 months, and the result was 33 responses from 27 different states including the District of Columbia. The complete list of respondents is provided in Table B1.

Table B1. Micro-grid Survey Respondents

State	Respondent*	Organization
AK	Jerry Burton, Utility Engineering Analyst	Regulatory Commission
AL	Janice Hamilton, Director	Alabama PSC, Energy Division
DC	Grace Hu, Chief Economist Dan Cleverdon, Technical Advisor	Washington, DC PSC Washington, DC PSC
DE	Robert Howatt, Public Utilities Analyst	Delaware PSC
FL	Hurd Reeves, Government Analyst	Florida PSC
GA	Philip Bedingfield, Public Utilities Engineer	Georgia PSC
IA	David Lynch, General Counsel John Pearce, Utility Specialist	Iowa Utilities Board
IL	Philip Roy Buxton, Program Manager	Illinois Commerce Commission
IN	Erin Peters, Assistant General Counsel	Utility Regulatory Commission
LA	Tulin Koray, Economist	Louisiana PSC
MA	Robert Harrold, Assistant Director, Electric Power Division	Department of Telecommunications and Energy
MI	Tom Stanton, Technical Assistant	Michigan PSC
MN	Jen Peterson, Energy Tech Team Supervisor Alvin Bierbaum, Staff Engineer	Minnesota State Energy Office Minnesota PUC
MO	Warren Wood, Energy Dept. Manager	Missouri PSC
NJ	Carl Dzierzawiec, Principle Engineer Scott Hunter, Renewable Energy Program Admin.	Board of Public Utilities
NY	Leonard Van Ryn, Assistant Counsel	Department of Public Service
OH	Jan Karlak, Utilities Specialist	Ohio PUC
OR	Lisa Schwartz, Senior Analyst David Stewart-Smith, Asst. Dir. Energy Resources	Oregon PUC Oregon Department of Energy
PA	Karen Oill Moury, Executive Director	Pennsylvania PUC
SC	Phil Riley, Advisory Staff Engineer	South Carolina PSC

SD	not provided	South Dakota PUC
TX	Jess Totten, Electric Division Director	Texas PUC
UT	Lowell Alt, Executive Staff Director	Utah PSC
VT	Ed McNamara, Staff Attorney	Vermont Public Service Board
WA	Douglas Kilpatrick, Assistant Director of Emergency & Planning	Utilities and Transportation Commission
WI	Scott Cullen, Chief Engineer , Gas & Energy Div.	Wisconsin PSC
WY	Ruth Hobbs	WY PUC

** Many respondents conferred with associates to ensure that their responses were valid and representative.*

Despite progress in most states on the technical and procedural requirements for traditional distributed energy resources, it is not clear that this translates into regulatory clarity for micro-grids. Among 24 states that reportedly have some interconnection procedures for DERs, respondents from 13 states believe these procedures would definitely or probably apply to micro-grids; 6 states indicated that these procedures would definitely or probably not apply to micro-grids; and 5 states indicated that it was unclear. Among respondents from the 19 states that have technical interconnection requirements, 11 respondents believed that such requirements would definitely or probably extend to micro-grids in their states; 4 indicated that they would probably not extend to micro-grids; and 4 were unsure. A state-by-state breakdown is provided in Table B2.

Table B2. Survey Responses to Questions About Micro-grid – Utility Interactions

	Have applicable rules for traditional DERs?	Would these rules that apply to DERs also apply to micro-grids?				
		Yes	Probably	Probably Not	No	Unclear / Respondent Unsure
Tariff Arrangements	25 states	FL, GA, MA, MN, TX, WA, WI	AL, IL, MO, PA	DC, IN, LA, NJ, OH, UT, WY	AK	IA, MN, NY, OR, SD, VT
Interconnection Procedures	24 states	DE, GA, IA, MA, MI, MN, TX, WA, WY	AL, MO, PA, VT	IN, OH, UT	AK, FL, LA	DC, NJ, NY, OR, WI
Technical Interconnection Requirements	19 states	AK, GA, IA, MN, WA, WI, WY	DE, MI, MO, PA	DC, IN, NJ, OH	-	NY, OR, SD, VT

The full list of responses provided by respondents are provided in Table B3, followed by the original survey that was sent to regulators in Figure B1.

Table B3. Complete Survey Responses from State Regulators

Alabama			
Rick Cleckler, Engineer, Public Service Commission			
5	Yes, the micro-grid customers would have to generate their own power (Alabama Code 37-14-1).		
6	No.		
7	Under certain conditions, Alabama Code 37-14-1 allows new industrial customers (2,500 KW and larger) to choose their own electric supplier.		
8	See #5 and #7.		
9	No		
10	See #7.		
11	Yes. See #5 and #7.		
12	Yes	13	Probably
14	No	15	*No response*
16	Yes	17	Probably
18	Only if they come under APSC regulation		
19	Not Sure	20	Probably
21	Unsure		
22	Unsure		
23	Both state and local agencies		
24	No		
Alabama			
(name not given)			
5	Yes, however, they must seek permission from the Alabama Legislature to form an Electric Co-op, otherwise the answer is No		
6	Yes, they would have to go to the AL Legislature to form an investor own utility outside of the city limits or a municipal inside the city, otherwise No.		
7	I'm unsure		
8	No, Alabama is not open for business. Only the legislature can change the codes and laws		
9	No		
10	Laws do not permit in Alabama		
11	Yes, service areas are defined by Alabama legislature. Yes, primary service provider can prevent other from building in the area. Only the Alabama legislature can overrule his provision.		
12	Yes	13	No
14	Not sure	15	*No response*
16	Not sure	17	*No response*
18	I'm unsure.		
19	Yes	20	Yes for retail; No for wholesale
21	I'm unsure		
22	*No response*		
23	Both state and local agencies		
24	N/A		
Alabama			
Janice Hamilton, Division Director, Energy Division			
5	Maybe. I think this scenario would qualify one to be compensated under utility's standby generation rate (SG) on an intermittent basis. A continuous supply of power might require a special contract between the parties based on Rate SG. The units would be operated by the local utility.		
6	Probably. The terms of Rate SG are such that the local utility maintains control of the generating facility. An agreement between the parties would need to be struck in order to vary from the terms of this rate.		
7	Generally, yes. I don't think the size of the power supply is a factor in considering whether or not the micro-grid		

	would be regulated. It is a variable of how many end-use customers are served from the facility.		
8	Yes. It seems to me that this scenario would be treated similar to an electric cooperative if the power supplied is consumed by the owners of the units according to state law.		
9	Yes. It seems to me that this scenario would be treated similar to independent power producers or other cogenerators according to state law.		
10	I don't think so but I am not sure.		
11	Yes. Probably so unless the micro-grid only serves the parties that own the generating facilities.		
12	Yes	13	Probably
14	Not sure	15	Not sure
16	Yes	17	Probably
18	There are such rules for regulated utilities. Variances from these rules are addressed on a case-by-case basis.		
19	Probably	20	Probably
21	I am not knowledgeable about environmental requirements regarding such unregulated electric generators.		
22	Not sure		
23	Both state and local agencies		
24	Not sure		
Comments: Sorry for the delay in our responses. This a new, uncharted area for our state.			
Alaska			
Jerry Burton, Utility Engineering Analyst, Regulatory Commission of Alaska			
5	No group of customers may sell to the grid. Under Alaska Statute a single owner may self generate and sell up to 100 kW to the certificated utility at a tariff purchase rate.		
6	No		
7	No		
8	No		
9	No		
10	No		
11	Yes utilities have service areas. The utilities can block anyone with more than 10 customers or anyone who takes one of the utilities present or previous customers.		
12	Yes	13	No
14	Yes	15	Yes
16	Yes	17	No
18	No		
19	Yes	20	Yes
21	No		
22	No		
23	State agencies		
24	No		
Delaware			
Robert Howatt , Public Utilities Analyst, Delaware Public Service Commission			
5	It is legal for a group of customers to build a micro-grid and interconnect at distribution voltages. Such group would need to register as a Third Party Supplier, meet host utility interconnections requirements, and meet DNREC environmental requirements. This answer is not defined in law and it is open to regulatory interpretation. However, host utility interconnection requirements have been approved by the regulatory body and DNREC is in process of adopting DNREC Regulation No. 44, regulating air emissions and permitting for distributed generation units.		
6	No. Independent companies would have the same requirements if serving Delaware customers. If the interconnection was for wholesale sales, external to Delaware, they would not have to register as a third party supplier.		
7	Size of the generation unit may generate more restrictive interconnection requirements. Size would not impact the legality, but if they intended to sell on the wholesale market, there would also be PJM membership, interconnection standards, feasibility studies, interconnection studies and deliverability tests, depending on what products the generator was providing (energy only, capacity, regulation, etc).		
8	Same as 5. Probably more rigorous interconnection standards and no requirement for state regulatory approval. PJM and the Transmission owner (host utility) become the dominant players.		

9	No		
10	A micro-grid interconnected to the host utility, providing energy (not separately distributing it) isn't a legal issue regardless of size. Size just has different standards or different agencies to deal with. The intent to be a wholesale or retail generator also creates differences that may not be related to size.		
11	Perhaps. If the definition of micro-grid includes a distribution system for water, sewer or electric and the territory has already been allocated to an existing utility, the micro-grid owner would have to negotiate with the utility and the utility would have no requirement to sell their delivery service facilities. Construction of their own delivery facilities would not be permitted. If the micro-grid was only interconnected internally for the purpose of consolidating generation and a single point of interconnection was proposed to the utility for the purpose of supplying energy only to customers via the utility distribution system, service territories would not come into play.		
12	No	13	*No response*
14	Yes	15	Probably
16	Yes	17	Yes
18	Electric utilities per the 1999 Restructuring Act are permitted to bill delivery, transmission and energy services in total. A customer of a third party energy supplier may elect to have two bills, one for energy and one for delivery and transmission. In addition, the Commission may permit third party metering and billing is so inclined, but that has not happened. Other issues are settled on a case by case basis.		
19	Probably not	20	Probably not
21	Proposed DG air quality regulations apply to all "small scale" stationary generators. There is no lower or upper limit in the proposed regulation which is a sticking point. Currently anything over 300KW has air quality requirements.		
22	Within the proposed rules, Combined Heat and Power units have different somewhat less restrictive air quality requirements. Currently they have the same requirements as any other units.		
23	Local agencies		
24	*No response*		
Comments: Rules and regulations are different depending on intended wholesale or retail application more so than on size, although larger units tend to be wholesale. In DE, principle requirements would fall to local agencies for siting, DNREC for environmental permitting and the host utility for interconnection. The Commission's principal involvement is approval of host utility tariffs and certification of applications for third party supplier status.			

District of Columbia			
Grace Hu, Chief Economist, DCPSC			
5	We do not have specific law addressing micro-grid. We issued a NOPR for net metering and the Commission will have a final rulemaking once the review and comment process is done.		
6	N/A		
7	N/A		
8	Interconnection at transmission voltage is FERC jurisdiction		
9	No		
10	No		
11	Yes. PEPCO has unique service territory. There is no law prohibiting this right now. Distribution utility, of course, can voice its objection if they do not like the idea.		
12	Yes	13	Probably not
14	Yes	15	Probably not
16	No	17	No
18	Case by case basis		
19	Probably	20	Not sure
21	Not sure		
22	Not sure		
23	State agencies		
24	For example, our net metering facilities are at or below 100 kWs. We have not defined the DG size yet.		

District of Columbia	
Dan Cleverdon, Technical Advisor, DC Public Service Commission	
5	Under current PSC rules it would be legal. Rules for interconnection are part of an open docket in DC. We are also waiting on PJM to finalize technical interconnection rules for use within the PJM footprint. If the entity sold on the wholesale market it would be subject to PJM rules and requirements. It could also possibly qualify for DG benefits from PJM.

6	No difference from #5		
7	I am not aware of any size restrictions other than size related interconnection requirements.		
8	Same answer as above. I am not aware of any distinction in the District between connection at distribution or transmission voltages.		
9	No		
10	Size would affect interconnection rules and treatment by PJM as DG or a regular wholesale source.		
11	There is only one regulated LSE in the District, PEPCO. In the past PEPCO has not been receptive of DG or micro-grids and I personally would expect it to oppose micro-grids.		
12	Being developed	13	*No response*
14	Being developed	15	*No response*
16	Being developed	17	*No response*
18	At present these issues would be settled on a case-by-case basis.		
19	No	20	Probably not
21	I am not aware of any special status for small generators in the District.		
22	I am not aware of any special status for small generators in the District.		
23	*No response*		
24	In the District of Columbia local agencies have the same powers as state agencies.		
Florida			
Hurd Reeves, Government Analyst II, Public Service Commission			
5	Generation and consumption must be the same entity. PW Ventures Declaratory statement. Selling power to one retail customer is considered a retail sale and thus subject to PSC regulation.		
6	No		
7	No		
8	See answer to question #5.		
9	No		
10	No		
11	Territorial agreements are approved by the Commission. As long as generator and customer are the same, micro-grid can be developed. Self-service wheeling rule no. 25-17.0883 F.A.C. Commission also has authority to resolve territorial disputes.		
12	Yes	13	Yes
14	No	15	*No response*
16	Yes	17	No
18	N/A		
19	Yes	20	Not sure
21	Not PSC jurisdiction. Suggest contact Department Environmental Protection, Buck Oven (850) 487-0472.		
22	See answer to no. 21.		
23	State agencies		
24	Yes, plants smaller than 75MWs Steam are under local jurisdiction.		
Georgia			
Philip Bedingfield, Public Utilities Engineer, GA Public Service Commission			
5	A micro-grid as described would be legal provided that all of the premises receiving service within the micro-grid are under one ownership, and no lines cross public roads or other similar properties. The micro-grid would also be legal in the case of various owners of buildings and facilities, provided that no lines cross public roads or other similar properties, and that the electrical energy and capacity is furnished to the users of same at no profit, an administrative fee being permissible. The above situations would be legal to the best knowledge of GA PSC staff based on input from regulated utility. The circumstances described above should be viewed as limited exceptions to the following general advice from the utility and its counsel: ""Premises" is a term defined by the GA Territorial Electric Service Act, which assigns certain service rights. It appears that a micro-grid would likely entail multiple premises under the Territorial Act. An operator of a micro-grid likely would be required to qualify as an "electric supplier" and provide service in accordance with the Act in a fashion not inconsistent with rights as assigned by the GA Territorial Electric Service Act Because the Act divides the state up into assigned territories for electric suppliers, a micro-grid operated by someone other than one of the existing electric suppliers in the state could not be set up to sell electricity to retail customers. But a scenario such as the college campus would be feasible because it is all on one premise with many facilities." Except for the "limited exceptions" mentioned above, the Georgia Territorial Electric Service Act, OCG 46-3-1, and subsequent case law, would prohibit other		

	configurations of such a micro-grid.		
6	No. See #5		
7	No		
8	See #5		
9	See #5		
10	No, see #5		
11	Yes. And no, except that the micro-grid could not operate in conflict with OCG 46-3-1 and subsequent case law.		
12	No	13	*No response*
14	Not sure	15	*No response*
16	Yes	17	Yes
18	Yes. See 5, and http://www.southerncompany.com/gapower/pricing/gpc-pdf/section-a.pdf.		
19	Yes	20	Yes
21	I don't think so. I believe all sources are treated equally.		
22	Don't know		
23	State agencies		
24	Location of generation plants not included in the Integrated Resource Planning requirements of OCG 46-2-1 and associated GPSC Rules are not subject to GPSC regulation as to siting.		
Illinois			
Philliph Roy Buxton, Engineering Program Manager, Energy Division, IL Commerce Commission			
5	Section 3-105 of the Illinois Public Utilities Act {220 ILCS 5/3-105] defines a public utility as being offered for "public use". Therefore, if a group of private parties wished to own and operate a private micro-grid, I can see no reason why they could not do that. However, the connection to the area grid is another matter. Still, if the connection were accompanied by a retail electric sales meter, then it might work, but not under any existing tariff of which I am aware. Please understand that you are getting a legal opinion from an engineer and it is worth just as much as you would think it is.		
6	I would think the answer would be the same except for those utilities in Illinois that have tariffs that forbid sales for resale. In that instance, purchase of electricity by the independent micro-grid owner for resale to the customers would not be possible. Of course, the company might be considered an Alternative Retail Electric Supplier. If so, then those statutes and rules would apply. 220 ILCS 5/16-102 83 Ill. Adm. Code 451		
7	Not for any reason that I can think of.		
8	Same answer as #5 above. I do not see why the voltage matters.		
9	Same answer as #6 above.		
10	Same answer as #7 above.		
11	No, utilities could try to object to the construction of another utility within their service territory, but a customer can build anything he wants.		
12	Yes	13	Probably
14	No	15	*No response*
16	No	17	*No response*
18	I do not know. I do not think the Illinois Commerce Commission has anything.		
19	Not sure	20	Not sure
21	Ask the Illinois EPA.		
22	Ask the Illinois EPA.		
23	Local agencies		
24	*No response*		
Comments: This is the very first interest I have heard expressed in a micro-grid by anyone.			
Indiana			
Erin Peters, Assistant General Counsel, Indiana Utility Regulatory Commission			
5	While we emphasize that this question is open to interpretation by state legislators and that this issue has never been considered in Indiana, a micro-grid (as defined above) that interconnects with the area grid at distribution voltages is likely to be permissible under Indiana Code 8-1-2 or 8-1-2.4. However, because all areas of the state are currently served by utilities with valid certificates of territorial authority, the only circumstance in which a micro-grid could operate, that we can foresee, is by seeking and obtaining permission from an authorized utility to operate within its territory.		
6	No		

7	No. Generally, any utility providing power to the public, regardless of size, falls within this Commission's jurisdiction. However, the level of regulation may vary under Indiana's Alternative Regulation statute (I.C. 8-1-2.5).		
8	Again, while we emphasize that this question is open to interpretation by state legislators and that this issue has never been considered in Indiana, a micro-grid (as defined above) that interconnects with the area grid at transmission voltages is likely to be permissible under Indiana Code 8-1-2 or 8-1-2.4. However, because all areas of the state are currently served by utilities with valid certificates of territorial authority, the only circumstance in which a micro-grid could operate, that we can foresee, is by seeking and obtaining permission from an authorized utility to operate within its territory.		
9	No		
10	No. Generally, any utility providing power to the public, regardless of size, falls within this Commission's jurisdiction. However, the level of regulation may vary under Indiana's Alternative Regulation statute (8-1-2.5).		
11	Yes, distribution utilities in Indiana have unique service territories and may prevent a micro-grid (as defined above) from being built within such territory; although under Indiana's Net Metering statute (170 IAC 4-4.2), utilities may be required to permit the interconnection of electrical generating facilities with capacities less than or equal to ten (10) kilowatts (kW).		
12	Yes	13	Probably not
14	Yes	15	Probably not
16	Yes	17	Probably not
18	Yes, the issues are governed by Indiana's Net Metering statute (170 IAC 4-4.2) which can be found at http://www.in.gov/iurc/rules/rules_index.html.		
19	Probably	20	Probably
21	We are unsure. (Please visit the Indiana Department of Environmental Management: www.in.gov/idem.)		
22	We are unsure. (Please visit the Indiana Department of Environmental Management: www.in.gov/idem.)		
23	State agencies		
24	Various state agencies have an interest in and authority to affect power plant siting; however, currently there is no centralized siting authority in Indiana. It is possible that small distributed plants may be subject to different considerations than large-scale plants, for example, under Indiana Code 8-1-2.5, Indiana's Alternative Regulation statute.		

Iowa			
David Lynch, General Counsel, Iowa Utilities Board			
5	Iowa Code section 476.1, which defines the public utilities subject to IUB jurisdiction, includes any person "furnishing electricity to the public for compensation." However, the statute also has an exception for "a person furnishing electricity to five or fewer customers either by secondary line or from an alternate energy production facility or small hydro facility, from electricity that is produced primarily for the person's own use." Thus, if the group totals 6 or fewer, and the largest of the customers is the owner of the facility, and it uses a "secondary line" or power from an AEP (i.e., wind or other renewable generation), the operation would not be considered a public utility subject to IUB regulation.		
6	Yes. The statute requires that the electricity be "produced primarily for the person's own use." That would appear to require that the largest user be the owner.		
7	Size is only a factor in that the number of customers is limited and, if the energy source is not an AEP, the power must be distributed by "secondary line." Iowa Code section 476.1. I am unclear regarding the second question and cannot answer.		
8	Only if the power source is an AEP or small hydro facility as defined in Iowa Code section 476.42.		
9	Yes, as per answer to number 6.		
10	See answer to question 7.		
11	Yes, the distribution utilities have exclusive service territories, pursuant to Iowa Code sections 476.22-476.26. However, that would not prevent construction of a micro-grid pursuant to the exception in section 476.1, because it would not be a public utility.		
12	Yes	13	Not sure
14	Yes	15	Yes
16	Yes	17	Yes
18	Yes		
19	No	20	No
21	I do not know. Environmental issues are handled by the Department of Natural Resources.		

22	Unknown		
23	State agencies		
24	See Iowa Code chapter 476A. Facilities with a total capacity below 25 MW are not required to obtain a certificate of public convenience and necessity. The requirement can be waived for larger facilities, pursuant to section 476A.15.		
Comments: Some of the answers I provided using the check boxes are, of necessity, over-simplified. In general, my responses to this survey should not be considered legal advice and are not binding on the Iowa Utilities Board. Any person considering construction of a generating facility or other electric facilities in Iowa is advised to consult his own attorney regarding the legal ramifications of that action.			
Iowa			
John Pearce, Utility Specialist, Iowa Utilities Board			
5	Yes, if FERC has designated it as a PURPA qualifying facility, and if the micro-grid is not a public utility as defined under Iowa Code 476.1. Under Iowa Code 476.1, an electric public utility is any person or entity that owns or operates facilities that furnish electricity to the public for compensation unless the electricity is furnished to five or fewer customers either by secondary line or from [a renewable energy] facility, from electricity that is produced primarily for the person's own use. Otherwise, if the micro-grid operates as a public utility, Iowa Code 476.22 - 476.25 prohibits it from providing service in the exclusive service territory of another public utility.		
6	No. However, ownership by an independent company would make it more likely to be a public utility as defined under Iowa Code 476.1.		
7	No, not as long as FERC still considers it a PURPA qualifying facility.		
8	Yes, if the micro-grid is not a public utility as defined under Iowa Code 476.1.		
9	No. However, ownership by an independent company would make it more likely to be a public utility as defined under Iowa Code 476.1.		
10	No		
11	Yes, under Iowa Code 476.22 - 476.25. Yes, if it is likely to be a public utility as defined under Iowa Code 476.1.		
12	Yes	13	Not sure
14	Yes	15	Yes
16	Yes	17	Not sure
18	No specific Iowa Utilities Board rules or regulations, unless they are Public Utilities under Iowa Code 476.1 (in which case, they could not provide service in another utility's service territory). However, they might be subject to various consumer protection statutes.		
19	Not sure	20	Not sure
21	Not sure		
22	Not sure		
23	State agencies		
24	Yes. Iowa Code 476A.1 - 476A.2 does not require certification of plant smaller than 25 MW.		
Louisiana			
Tulin Koray, Economist, Louisiana Public Service Commission			
5	This is illegal since it would be considered a public utility. Ref: Louisiana R.S. 45:1163		
6	No		
7	No. A customer of electric company cannot resell utility service according to Louisiana R.S. 45: 1163.		
8	No		
9	No		
10	No		
11	Utilities GTD have unique service territories. N/A		
12	Yes	13	Probably not
14	Not sure	15	*No response*
16	Being developed	17	No
18	No, not allowed		
19	Probably	20	Not sure
21	Don't know. Department of Environmental Quality handles this.		
22	Don't know		
23	Both state and local agencies		
24	Don't know. Due to environmental requirements, DEQ may know this.		

Massachusetts			
Robert Harrold, Assistant Director, Electric Power Division, Department of Telecommunications and Energy			
5	May be legal via consent of the local distribution company. Within the confines of the micro-grid distribution service would have to be offered, and Massachusetts law grants the electric distribution company an exclusive right to provide that, unless the company agrees otherwise. Massachusetts General Laws ch. 164, Section 1B(a)"...the distribution company shall have the exclusive obligation to provide distribution service to all retail customers within its service territory, and no other person shall provide distribution service within such service territory without the written consent of such distribution company which shall be filed with the department and the clerk of the municipality so affected."		
6	No difference in that the initial hurdle remains, i.e., the permission of the distribution company to allow another entity to provide distribution service in its service territory.		
7	No difference in terms of size.		
8	Interconnection voltage makes no difference with respect to the hurdle stated in response to question 5.		
9	No difference.		
10	No difference due to size.		
11	Yes. See response to question 5.		
12	Yes	13	Yes
14	No	15	No
16	Yes	17	Yes
18	No rules or regulations for ESCOs or district heating companies.		
19	Not sure	20	Not sure
21	Don't know		
22	Don't know		
23	State agencies		
24	State siting process applies to generators of 100 MW or larger.		
Michigan			
Tom Stanton, Technical Assistant, Competitive Energy Division, Michigan Public Service Commission			
5	Yes, it appears possible. It would be open to interpretation by state regulators, I believe.		
6	No, it does not appear that ownership of the micro-grid is a determinant.		
7	Size (in kW) is probably not a legal determinant. Size of property in question, and whether a single parcel of land could end up being a determinant. Number of customers participating, and legal status of the relationships between those customers is probably the most important legal question.		
8	Yes, I believe it can be done legally. Yes, I think it is open to interpretation by regulators. Michigan law pretty clearly allows this for "contiguous industrial facilities" (see MPSC March 12, 2003 Order in Case No. U-12980, online at http://www.cis.state.mi.us/mpsc/orders/electric/2003/u-12980.pdf.		
9	No		
10	No		
11	Yes, most have unique service territories. There is one small area where multiple utilities are free to compete for customers in one service territory. No, I doubt that a utility could prevent a micro-grid from being built within its service territory.		
12	Yes	13	Not sure
14	Yes	15	Probably
16	Yes	17	Yes
18	No, I don't believe there are such rules & regulations. I expect they would be settled on a case-by-case basis. Michigan has some history of regulating rates, terms, and conditions of service for steam utilities (i.e. district heating companies), though… which would cover billing rules and billing dispute resolution.		
19	Probably not	20	Probably not
21	Questions 21 and 22 are temporarily unanswered. My preliminary answer is no, there is no special status for small electric generating units. Units bigger than some threshold (I believe 120 million Btu/hour output) must be permitted by our air quality regulators.		
22	My preliminary answer is no, there is no special status for CHP units.		
23	Local agencies		
24	*No response*		
Minnesota			

Alvin C. Bierbaum, Staff Engineer, MN Public Utilities Commission			
5	MN has a large number of manufacturing firms, college and privately owned apartment/condo/hospital facilities that have their own generation equipment. They normally have a primary metering hookup with their utility where they can generate power for their own use, or for operation during utility outages. MN law typically does not permit a group of customers, who would choose to own and operate their own distribution system, where they sell power to the public, unless they declare themselves a utility. MN Statutes allows some exceptions. No person/persons shall be deemed a public utility if they provide services to their apartment, condo, or trailer park. In such a case, the utility would supply the bulk supply with the owners distributing and metering the power to individual tenants or condo owners. The Statutes also exempt those owners that might provide service to 25 or fewer customers. MN has established service area boundaries. I doubt that any utility would permit a group of investors to come in and take over their service territory w/o a legal battle. MN does allow municipal utilities who annex the land where the utility service is supplied by a Coop or IOU to take over service, provide the original serving utility is properly compensated for its investment and be willing pay 10 years of charges based on lost revenue from new customers (around 30 mills). If the group of customers/entity owning their own distribution system wishes to cogenerate, they must seek an agreement with their utility concerning generation interconnection standards per MN rules. The group of investors must also seek permission of the Midwest Independent System Operator, which significantly clouds the situation. Wind generation owners in western MN are dealing with this problem, for obtaining outlet transmission facilities. In summary, it is unclear just how successful a customer owned micro-grid would be accepted by MN utilities, customers having concerns about retail rate abuse, and MISO requirements.		
6	I don't think so.		
7	If the micro-grid is cogenerating/selling their power to their local serving utility, they must comply with MN Rules concerning interconnection standards and Commission approved rate schedules. As mentioned before, it is unclear whether a micro-grid consortium could set themselves up as an utility, and provide power to customers on their own distribution system on a large scale. Certainly, submetering would be permitted in a privately owned distribution system serving a college, hospital, or industrial campus having their generation, where the micro-grid is buying and selling power on a primary metering basis and having an cogeneration interconnection agreement with their serving utility.		
8	As mentioned before, we have numerous customers who have built their own micro-grid system to serve their own needs and cogenerate with their local utility. They normally would not be permitted to sell power to other customers, on a large scale, in competition to their local utility. I do not believe that it matters whether the voltage is distribution or transmission class.		
9	Should not make a difference.		
10	Not at the present time.		
11	Yes and yes		
12	Yes	13	Probably
14	Yes	15	Yes
16	Yes	17	Probably
18	Not at the present time.		
19	Probably	20	Probably
21	I believe that the MN Environmental Agency has jurisdiction over all types.		
22	We have a number of utilities that sell their waste heat to others. This is a non-regulated function as long at the generating unit meets environmental and good engineering standards.		
23	Both state and local agencies		
24	Yes		
Comments: It appears to me that if micro-grids become popular, we take the chance of diminished our state regulatory oversight, thus providing less protection against abuse from greedy owners/operators.			

Minnesota	
Jen Peterson, Supervision Energy Tech Team, State Energy Office	
5	Yes, though MN law only goes up to 10 MW and is more restrictive as you get greater than 500 kW for distribution. The system you've defined is asking a lot of the distribution circuit's load.
6	No
7	Yes, size is a factor given the varying impacts on the system.
8	Yes. There are wind systems that interconnect directly with the transmission system. At the transmission level a MISO review is required.
9	No

10	Yes, see #7.		
11	Yes and yes		
12	Yes	13	Yes
14	Yes	15	Yes
16	Yes	17	Yes
18	Yes		
19	Probably	20	Probably
21	*No response*		
22	No		
23	State agencies		
24	Depends on the size of the system. Smaller systems are subject to local jurisdiction.		
Missouri			
Warren Wood, Energy Department Manager, Public Service Commission Staff			
5	If a customer wanted to build generation to serve their own purposes, it is permitted by current law/regulations. If a group of customers bought a central generation station to serve a particular group of customers in a regulated electric utility service territory I don't believe that would be permissible under current law/regulations. Utilities have a franchise and service territory where they are the only provider of electricity and have an obligation to serve.		
6	No, I don't believe the answer changes unless the company was the electric utility with the service territory encompassing the customers in question.		
7	Yes, customers serving themselves with self-owned and operated generation are permissible while larger group owned and operated generation would not be permissible.		
8	I don't believe this would be legal in the current statutory/regulatory framework unless this group of customers was operating as a municipal, a coop, or a regulated electric service provider. They could possibly operate as a different sort of customer group if they were completely outside of any city limits or service territories.		
9	I don't believe the answer changes.		
10	Not unless the size of the micro-grid goes down to a very small number of customers (1 to 2).		
11	Utilities in our state do have service territories and could potentially prevent micro-grids from being built within their service territory. Utilities could construct micro-grids within their service territories to serve customers but we have not seen this happen yet.		
12	Yes	13	Probably
14	Yes	15	Probably
16	Yes	17	Probably
18	I'm not aware of any current rules or regulations that explicitly dictate how micro-grids, service companies or district heating companies must interact with their customers outside of our regulated utilities. Extensive tariff and rule provisions apply to these relations regarding services provided by regulated utilities to their customers.		
19	Probably	20	Probably
21	Small electric generating units do have a special status for purposes of state environmental regulations but I'm not sure what the maximum size limit is on this special status.		
22	The special designation that is applied to small electric generating units also applies to cogeneration and CH&P applications.		
23	Local agencies		
24	Power plant siting is a decision of the utility within their service territory. No siting authority is required outside staying within their service territory and acquiring the necessary air, land and water disturbance permits. Outside of their service territory they are required to get a Certificate of Convenience and Necessity to build/operate in the areas outside of their service territory.		
Comments: One significant area that wasn't addressed, although I'm sure it has been part of your analysis, is the increasing levels of dependence on natural gas this trend could cause and the lower heat rate of these smaller facilities. In general these small facilities are more expensive on a delivered kWh basis vs. large central generating facilities. Central control of the flows on the interconnections would also be an issue to address. I'm in support of wind and PV but these grids would require other resources be ready to cover the load when wind and PV weren't providing adequate capacity and energy to serve load (and they are relatively expensive at this time).			
New Jersey			
Carl J Dzierzawiec, Principal Engineer – Utilities, Energy / NJ Board of Public Utilities			
5	The "Electric Discount and Energy Competition Act" (P.L.1999, c.23) is New Jersey's deregulation law. It can be		

	seen at http://www.state.nj.us/bpu/wwwroot/energy/Dereglaw.pdf. Per N.J.S.A. 48:3-51, an "On-site generation facility" means a generation facility, and equipment and services appurtenant to electric sales by such facility to the end use customer located on the property or on property contiguous to the property on which the end user is located. An on-site generation facility shall not be considered a public utility. The property of the end use customer and the property on which the on-site generation facility is located shall be considered contiguous if they are geographically located next to each other, but may be otherwise separated by an easement, public thoroughfare, transportation or utility-owned right-of-way.		
6	"Electric power generator" means an entity that proposes to construct, own, lease or operate, or currently owns, leases or operates, an electric power production facility that will sell or does sell at least 90 percent of its output, either directly or through a marketer, to a customer or customers located at sites that are not on or contiguous to the site on which the facility will be located or is located. The designation of an entity as an electric power generator for the purposes of this act shall not, in and of itself, affect the entity's status as an exempt wholesale generator under the Public Utility Holding Company Act of 1935, 15 U.S.C. s.79 et seq."Electric power supplier" means a person or entity that is duly licensed pursuant to the provisions of this act to offer and to assume the contractual and legal responsibility to provide electric generation service to retail customers, and includes load serving entities, marketers and brokers that offer or provide electric generation service to retail customers. The term excludes an electric public utility that provides electric generation service only as a basic generation service pursuant to section 9 of this act;		
7	The board may authorize an electric power supplier or basic generation service provider to cease offering net metering whenever the total rated generating capacity owned and operated by net metering customer-generators statewide equals 0.1 percent of the State's peak electricity demand or the annual aggregate financial impact to electric power suppliers and basic generation service providers Statewide, as determined by the board, exceeds $2,000,000, whichever is less;		
8	ANY connection to the transmission system is governed by the Pennsylvania, Jersey, Maryland (PJM) Interconnection and its applicable procedures. PJM is the regional transmission system operator (RTO) approved by the FERC.		
9	See #8		
10	For installations less than 10 MW see PJM's website at http://www.pjm.com/planning/downloads/small-resource.pdf.		
11	Yes, each utility has its own unique service territory. It is unclear whether a utility could prevent such “micro-grids”, as described, from being built.		
12	Not sure	13	*No response*
14	Not sure	15	*No response*
16	Not sure	17	*No response*
18	*No response*		
19	*No response*	20	*No response*
21	*No response*		
22	*No response*		
23	*No response*		
24	*No response*		
New Jersey			
Scott Hunter, Renewable Energy Program Administrator, Office of Clean Energy NJ BPU			
5	I am unsure, since there is no specific enabling legislation or policies for a micro-grid in NJ. In my opinion/interpretation, the group of customers could only reach goals above 2 MW by aggregating installations that were made up to the 2 MW maximum as allowed by our net metering standards.		
6	I am unsure, since there is no specific enabling legislation or policies for a micro-grid in NJ.		
7	I am unsure, since there is no specific enabling legislation or policies for a micro-grid in NJ.		
8	I am unsure, since there is no specific enabling legislation or policies for a micro-grid in NJ.		
9	I am unsure, since there is no specific enabling legislation or policies for a micro-grid in NJ.		
10	I am unsure, since there is no specific enabling legislation or policies for a micro-grid in NJ.		
11	I am unsure, since there is no specific enabling legislation or policies for a micro-grid in NJ.		
12	Yes	13	Probably not
14	Yes	15	Probably not
16	Yes	17	Probably not
18	I am unsure		

19	Probably	20	Probably
21	not to my knowledge, dirty air is dirty air, ask the folks who encouraged MTBE about "net environmental benefit"		
22	not to my knowledge, dirty air is dirty air, ask the folks who encouraged MTBE about "net environmental benefit"		
23	Both state and local agencies		
24	Unsure		
New York			
Leonard Van Ryn, Assistant Counsel, NYS Department of Public Service			
5	Under Public Service Law (PSL) Section 68, the Commission has the discretion to grant a Certificate for construction of electric plant; it may regulate operations of a micro-grid more lightly than a traditional electric utility. Some micro-grids might qualify for an exemption from Commission regulation under PSL Sections 2(2-a)-2(2-4) and 3(13).		
6	The answer depends upon the degree of control exercised by the independent company over the property and operation of the micro-grid.		
7	While the Public Service Commission could approve a Certificate for a micro-grid of any size, complexities of the decision would increase in proportion to the scope and size of the proposed power sources. The exemptions(see Q#5 response)adhere only to generators with a capacity of less than 80 MW, serving retail users located at or near the generator's site.		
8	Same answer as the response provided to Q#5, relating to distribution.		
9	Same answer as the response provided to Q#5, relating to distribution.		
10	Same answer as the response provided to Q#5, relating to distribution.		
11	Utilities provide service in specific territories; some dual service arrangements can and have been allowed.		
12	Yes	13	Not sure
14	Yes	15	Not sure
16	Yes	17	Not sure
18	Unless exempt, a micro-grid corporation is an electric corporation subject to Commission jurisdiction. The Commission would adopt rules for micro-grids when the question and need to decide issues arose, possibly in relation to a decision on the scope of regulation applicable to a particular micro-grid. The Commission has adopted uniform practices applicable to ESCOs.		
19	Not sure	20	Not sure
21	The State Environmental Quality Review Act (SEQRA), administered by the State Department of Environmental Conservation, applies to electric generating units, without regard to size threshold, provided that a discretionary decision from a governmental entity is required.		
22	Under SEQRA, no special status is provided for these units.		
23	Both state and local agencies		
24	Unless exempt or restricted to on-site generation, a generator must obtain a certificate under PSL Section 68 before commencing construction; granting the Certificate is a discretionary act and facility size and scope are considerations taken into account.		
Ohio			
Jan Karlak, Utilities Specialist, Public Utilities Commission of Ohio			
5	There is no specific provision under Title 49 of the Ohio Revised Code for the construction or operation of a "micro-grid" as defined by this survey.		
6	No. A wires company "distributing" power services to retail electric customers will likely fall under the definition of an "electric distribution utility" section 4928.01(6) unless it is a municipal utility or a rural electric cooperative. Such utility is subject to the supervision and regulation by the Ohio commission to the extent that authority is not preempted by federal law. Section 4928.05(2)		
7	Not necessarily. No electric distribution utility on or after the starting date of competitive retail electric service shall knowingly distribute electricity, to a retail customer in this state, for any supplier of electricity that has not been certified by the commission pursuant to this section. Revised Code Section 4928.08(E)		
8	If this were to occur in Ohio, such interconnection would have to occur in accordance with the interconnection provisions of the transmission provider's Open Access Tariff on file with the Federal Energy Regulatory Commission. There are two regional transmission providers in Ohio: the Midwest ISO and PJM Interconnection, L.L.C.		
9	No. The micro-grid owner would still be subject to the rules in place in the Midwest ISO or PJM.		
10	No. Total capacity would only come into question in the matter of State siting of the generating resources if this siting were done in the aggregate. The lower limit for such generation siting in Ohio is 50MWs.		

11	Yes. Whether at the distribution or the transmission level, the interconnection provider will be concerned with the feasibility, the system impact, and the use of facilities for any interconnection.		
12	Yes	13	Probably not
14	Yes	15	Probably not
16	Yes	17	Probably not
18	The Ohio Commission shall exercise its jurisdiction with respect to the delivery of electricity by an electric utility in this state on or after the starting date of competitive retail electric service so as to ensure that no aspect of the delivery of electricity by the utility to consumers in this state that consists of a noncompetitive retail electric service is unregulated. Sec.4928.05(2) (See also response to question 7 above.)		
19	Yes	20	Yes
21	This would depend on the location, the fuel, and whether or not there would be operating limits prescribed for the purposes of pollution control		
22	No. (See response to question 21 above.)		
23	Both state and local agencies		
24	See response to question 10 above.		
Comments: In my opinion, the concept of micro-grids has been introduced without much thought as to why and how customers want electric service delivered. It would appear that the purpose of the micro-grid is to replace a larger utility monopoly service with a smaller version of the same thing. In short, the customers of the micro-grid would have "no choice," they would be as much captive customers as those of the larger monopoly. Just because a micro-grid is smaller, doesn't make the price of the service "just and reasonable," the service more reliable, or the spread of such micro-grids more socially responsible nor will they necessarily reduce carbon dioxide. Indeed, their proliferation may contribute to more urban sprawl or loss of agricultural land and green space. When one also contemplates the financial consequences of having to set up a customer metering and billing system, a method for responding to customer service inquiries, new service requests, complaints of poor service quality, weather emergencies and restoration of service, tree trimming (hopefully there will still be trees within the micro-grid), maintenance and repair, the volatility of fuel prices, back-up electric supply service, while still delivering the safe and reliable service most electric customers in the U.S. "take for granted," the micro-grid concept seems to come up short and poorly defined.			
Oregon			
Lisa Schwartz, Senior Analyst, Oregon Public Utility Commission			
5	Interconnection would not be a legal problem, but the OPUC has not yet set technical standards, so requirements vary by utility. Retail access to the electricity is allowed only for nonresidential customers in the service areas of Portland General Electric and Pacific Power. Oregon's electric industry restructuring law requires the OPUC to "ensure that an electric company that offers direct access provides electricity service suppliers and retail electricity consumers access to its transmission facilities and distribution systems comparable to that provided for its own use." (ORS 757.637) The generating customer would have to be certified by the OPUC as an Electricity Service Supplier (ESS) if it sells to more than one customer. (OAR 860-038-0005(24)) The utilities have their own requirements for ESSs, including credit and electronic data exchange requirements. The customer-generator also would be considered a public utility subject to Commission regulation unless it met one of the exceptions in ORS 757.005, including solar and wind projects, selling to fewer than 20 residential customers, and Qualifying Facilities selling to Idaho Power (the only utility not exempt from Oregon's PURPA law). The Commission has proposed a legislative change to reinstate the exemption for Qualifying Facilities in PGE and Pacific Power territories. Senate Bill 1149 (1999 OR Legislature) inadvertently removed the exemption for Qualifying Facilities selling to these utilities.		
6	Maybe -- the issue revolves around sales vs. self-generation.		
7	No		
8	The FERC-approved OATT would control the interconnection; FERC would be the authority for sales if it were sales for resale (not net metering).		
9	I don't think so		
10	I don't think so		
11	Yes - unique territories. No retail access (sales by non-utilities to customers) is allowed in the service areas of consumer-owned utilities in Oregon.		
12	Yes	13	Yes
14	Yes	15	Yes
16	Yes	17	Yes
18	Yes. There are state rules for electricity sales to nonresidential customers of PGE and Pacific Power.		
19	No	20	No

21	Don't know. Ask the Oregon Dept. of Environmental Quality.		
22	They can apply for an exemption from state energy facility siting requirements if they meet the energy efficiency standard.		
23	State agencies		
24	Ask the Oregon Department of Energy: 503-378-4040 or visit www.energy.state.or.us. They have good info on siting on their Web site.		
Oregon			
David A. Stewart-Smith, Asst. Director, Energy Resources, Oregon Department of Energy			
5	I believe such an arrangement would not be legal in Oregon. The entity formed to operate the central electricity and heating system would likely be considered a public utility under Oregon law, and another utility cannot operate within the exclusive service territory of the larger utility. The definition of public utility can be found in ORS 757.005(1). It's conceivable that an arrangement where one owner of a large business or research "campus" leased space to other entities could pass muster, but I don't think the owner could meter electricity or central heat and sell it to their renting customers. It probably would have to be wrapped up into the lease.		
6	No, I don't believe so. The independent company would still be considered a public utility.		
7	There are exceptions in the definition for fewer than 20 residential customers, or for solar and wind to any number of customers, or for waste heat, or biogas generated heat.		
8	I don't believe such an arrangement is legal under OR law. An entity could connect at transmission voltages for the purpose of selling wholesale power into the grid, but not to provide retail electricity to customers, unless it was a regulated public utility or a legally constituted customer-owned utility.		
9	No		
10	I don't think so for the same reasons above.		
11	Yes to both questions.		
12	Yes	13	No
14	Yes	15	No
16	Yes	17	No
18	I don't think so. Cities can provide district heating services, but cities can also amend their charter to become customer-owned utilities. The City of Hermiston, Oregon voted to condemn the service territory of PacifiCorp several years ago to form a Municipal Utility.		
19	Yes	20	Probably
21	There are "small generators" that have a less demanding set of permit requirements, but they may also be limited by the number of hours per year they can operate.		
22	There are some special status rules of the state Energy Facility Siting Council exempting a high efficiency cogen facility from siting authority. Portions of such a facility are also eligible for a Business Energy Tax Credit, and/or low cost financing through the OR Dept of Energy. There is a special tariff for self generating customers if the facility is still connected to the grid to provide back-up power capability.		
23	State agencies		
24	Some of the rules are different. A facility may not be under state jurisdiction at all if it is less than 25 MW (fossil) or 35 avg. MW if it is wind, solar or geothermal. If above these sizes, but less than another set of triggers, the facility may be eligible for a shorter, expedited process.		
Pennsylvania			
Karen Oill Moury, Acting Executive Director, PA Public Utility Commission			
5	This scenario would generally be permitted, but existing interconnection requirements and standards may make it difficult to determine how this would be accomplished. The current rules primarily exist in electric utilities' tariffs. The PaPUC opened an advance notice of proposed rulemaking on November 18, 2004 at Docket No. L-00040168 seeking to eliminate unnecessary barriers to entry in the distributed generation market and to create uniformity in the procedures followed throughout the Commonwealth. In addition, Act 213 was signed into law on November 30, 2004 setting forth renewable portfolio standards. Section 5 of that Act provides for the development by the Commission of technical and net metering interconnection rules for customer-generators intending to operate renewable onsite generators in parallel with the electric utility grid, consistent with rules defined in other states within the service region of the regional transmission organization that manages the transmission system in any part of the Commonwealth. The Commission is required to develop those rules by November 2005.		
6	No		
7	The size does not affect legality or status of the micro-grid as a regulated entity.		

8	The Commission has relied upon the rules developed by the Federal Energy Regulatory Commission for interconnection at transmission voltages.		
9	No		
10	No		
11	Yes, distribution utilities have unique service territories. Currently, the utilities' tariffs would govern the development of a micro-grid within their service territories. However, the effect of the Commission's ANOPR and the provision in the renewables portfolio standards legislation would be to make these rules uniform throughout Pennsylvania.		
12	Yes	13	Probably
14	Being developed	15	Probably
16	Being developed	17	Probably
18	If micro-grid companies or similar organizations offer generation supply service to end-user customers, they would be required to obtain licenses from the Commission. As part of that process, they would be obligated to follow the Commission's rules regarding billing, dispute resolution, etc.		
19	Probably not	20	Probably not
21	The PA Department of Environmental Protection regulates this issue.		
22	The PA Department of Environmental Protection regulates this issue.		
23	Both state and local agencies		
24	Different rules do not exist for the siting of small plants.		
South Carolina			
Phil Riley, Advisory Staff Engineer, Public Service Commission			
5	Not legal under any circumstances. There are some provisions in South Carolina law for providing electric service to industrial parks, but interconnection with the regulated utility who has been assigned territorial rights in that area is not authorized.		
6	No		
7	No		
8	A micro-grid is not specifically defined in South Carolina's Code of Laws nor Rules and Regulations. At transmission voltages, an entity may be able to apply for a siting permit to build a generating facility whose output could be sold on the wholesale market if buyers can be found.		
9	No		
10	No		
11	Yes, South Carolina distribution utilities have unique service territories. The Code of Laws and Rules and Regulations could prevent micro-grids, NOT the regulated distribution utilities.		
12	No	13	*No response*
14	No	15	*No response*
16	No	17	*No response*
18	No		
19	Yes	20	Yes
21	No		
22	No		
23	State agencies		
24	Large-scale plants (> 75MW) are subject to the State's Utility Facility Siting and Environmental Protection Act. The laws are silent with respect to siting facilities smaller than 75MW.		
South Dakota			
Not listed, South Dakota PUC			
5	Utilities have defined service areas. A micro-grid has not been established in SD and the law is unclear regarding its establishment.		
6	Self-ownership may fit within the law. Independent ownership most likely would not be given established utility franchise areas, but the law is unclear.		
7	No size definition is given in the law.		
8	Obviously the legality of the micro-grid comes first. With that being uncertain, the answer to this question is also uncertain.		
9	Same as above.		
10	See #7		

11	Yes. May depend on ownership (user-owned v. independent), but it is unclear. User-owned more likely to fit within the law.		
12	Yes	13	Not sure
14	Yes	15	Not sure
16	No	17	*No response*
18	None operating, so no determination made if current utility rules would apply. Likely they would.		
19	Not sure	20	Not sure
21	Don't know		
22	None exist with state, but even so we do not have general environmental jurisdiction.		
23	State agencies		
24	The differences relate to degree of impact studies and study funding.		
Texas			
Jess Totten, Director, Electric Division, Public Utility Commission			
5	There are some circumstances in which this arrangement is permissible under state law. State law provisions are limiting factors, but their interpretation may not always be clear.		
6	Yes. If a separate company owns the distribution/delivery facilities of the micro-grid, it is likely that it would be considered an electric utility. It is quite difficult to create new electric utilities.		
7	No. Size is not important.		
8	There are some circumstances in which this arrangement is permissible under state law. State law provisions are limiting factors, but their interpretation may not always be clear.		
9	Yes. If a separate company owns the distribution/delivery facilities of the micro-grid, it is likely that it would be considered an electric utility. It is quite difficult to create new electric utilities.		
10	No. Size is not important.		
11	For the most part. There are existing areas of dual service, but no new duplicate service areas may be created.		
12	Yes	13	Yes
14	No	15	*No response*
16	Yes	17	Yes
18	There are rules that govern the retail sale of electricity that a micro-grid might be subject to.		
19	Probably not	20	Probably not
21	Environmental regulation in Texas is done by the Texas Commission on Environmental Quality.		
22	Don't know		
23	State agencies		
24	Don't know		
Utah			
Lowell Alt, Executive Staff Director, Public Service Commission			
5	It might be legal for those customers to produce their own power under exemptions from PSC regulation for a producer/tenants relationship or for members of an association of unit owners (Utah Code 54-2-1). Obligation of regulated utility to purchase excess power is dependent on type of power source (54-12-2 and 54-2-1) except for net metering for a customer (54-15-103). Wholesale sales would be covered by federal law. Utah has not adopted electric deregulation or retail customer choice legislation and therefore wholesale electricity purchases by retail customers are not permitted.		
6	Probably not		
7	Size is not believed to impact legality or regulated status.		
8	Believe answer is same as for question #5.		
9	Probably not.		
10	Size is not believed to impact legality or regulated status.		
11	Yes. It is unclear whether the possible exemptions from regulation mentioned in #5 would completely negate monopoly service area issues.		
12	Yes	13	Probably not
14	No	15	*No response*
16	Yes	17	Probably not
18	Not aware of any		
19	Probably	20	Probably
21	Our understanding is that the level of emissions - rather than the size of the generator - determines requirements,		

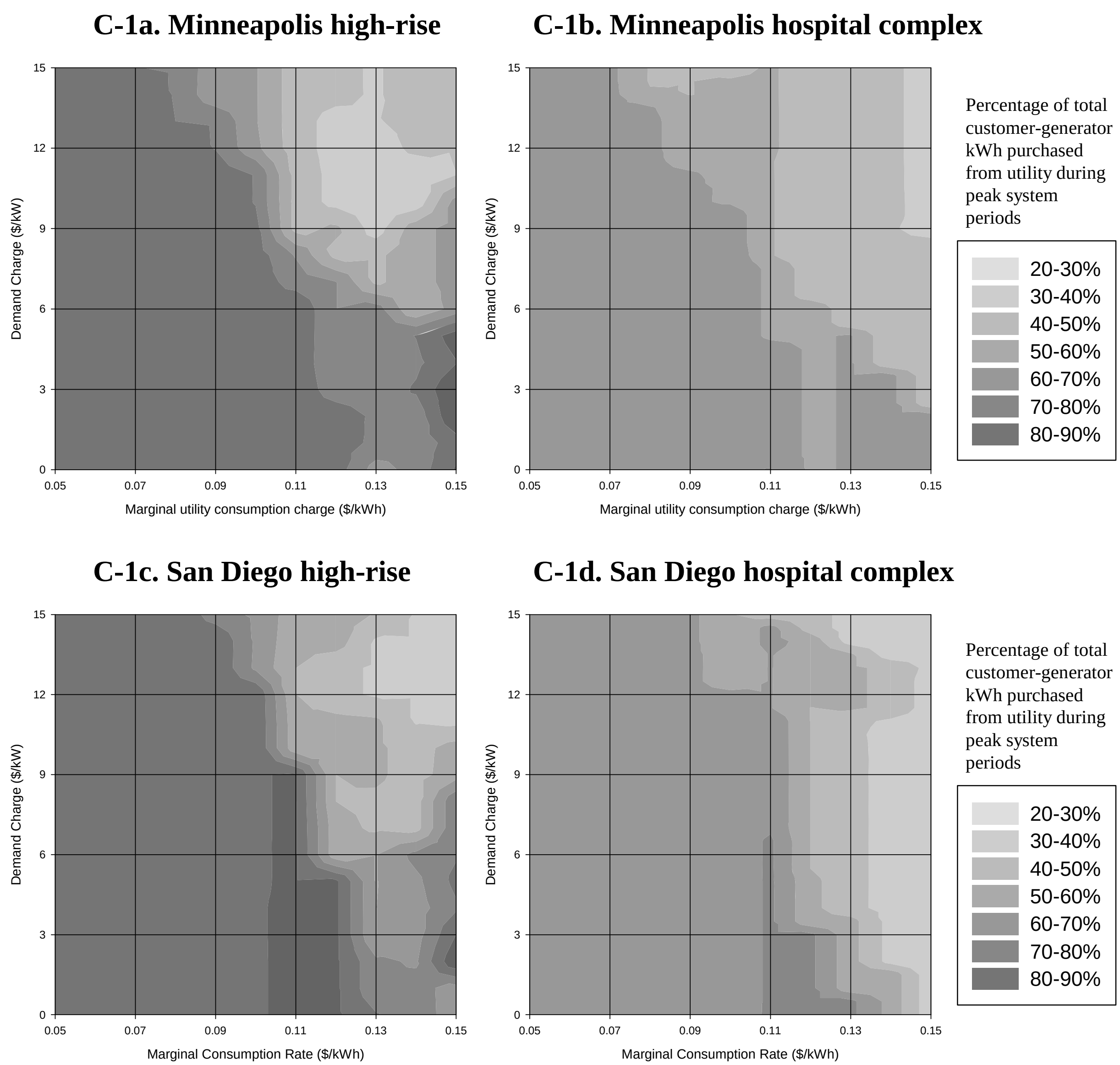
	but specific requirements should be obtained from the state department of environmental quality (www.eq.state.ut.us).		
22	Not sure. Check with state department of environmental quality (www.eq.state.ut.us).		
23	Both state and local agencies		
24	There is no single state agency responsible for electric generation siting. We are unable to answer this question for other state agencies as each has its own requirements. Utah law providing authority for the Public Service Commission over new electric generation does not address size differences.		
Vermont			
Ed McNamara, Staff Attorney, Vermont Public Service Board			
5	A certificate of public good is required for a generation unit that is connected to the grid. Additionally, depending on the structure of the micro-grid, it may qualify as a utility and would therefore need a certificate of public good to operate as a utility in Vermont		
6	Yes. This might affect whether the micro-grid would be considered a utility.		
7	Probably not		
8	See #5		
9	See #6		
10	See #7		
11	Yes. If the micro-grid is considered a utility, it would need the consent of the utility or approval from the Board to serve in an existing service territory.		
12	Yes	13	Not sure
14	Yes	15	Not sure
16	Yes	17	Probably
18	Yes, if they qualify as a utility under state law.		
19	Yes	20	Yes
21	Not sure		
22	No		
23	State agencies		
24	No, unless the micro-grid is considered to be net-metered.		
Washington			
Douglas Kilpatrick, P.E., Asst. Director, Emergency and Risk Management, Washington Utilities and Transportation Commission			
5	There are no statutes that expressly prohibit the construction of a micro-grid as defined in this survey. If the parties to whom it is connected own the micro-grid as a non-profit cooperative association, then the laws governing the association are found in Title 23.86 of the Revised Code of Washington (RCW). See http://www.leg.wa.gov/RCW/index.cfm?fuseaction=chapterdigest&chapter=23.86. At the same time, there are no statutes that require an electrical company to interconnect with the micro-grid for the purposes of purchasing or selling power to this entity, assuming it is organized as a cooperatively owned enterprise. See definition of electrical company in Title 80.04.010 RCW. http://www.leg.wa.gov/RCW/index.cfm?section=80.04.010&fuseaction=section		
6	An independent company that owns, installs, and maintains electrical distribution facilities may be considered a public service company and therefore be subject to the jurisdiction of the Commission. The Commission at hearing as set out in Title 80.04.015 RCW would determine regulatory jurisdiction. See http://www.leg.wa.gov/RCW/index.cfm?section=80.04.015&fuseaction=section		
7	No		
8	Same answer as #5 above.		
9	Same answer as #5 above.		
10	Same answer as #7 above.		
11	Distribution utilities in WA do not have franchised service territories as implied by this question. Rather, the legislature has declared it public policy that duplication of the electric lines of public utilities and other entities with authority to distribute electricity (e.g. public utility districts, electric cooperatives, municipal utilities, mutual corporations, etc.) is not efficient, nor in the public interest. See Title 54.48 RCW. For a further description of the issues surrounding electric utility service territories in Washington, see Section 5 of the report, Washington State Electricity System Study as published December 31, 1998. http://www.cted.wa.gov/energy/archive/6560/Final/fnl_6560sec_5.pdf. A distribution utility thus could not limit the building of a m-g within its area of service, however, as stated above, the public service utility would not		

	be required to interconnect to it if it were run as a cooperative utility or as privately-owned public service company.		
12	Yes	13	Yes
14	Yes	15	Yes
16	Yes	17	Yes
18	No. Issues are settled based on established procedures and policies of the cooperative association or business entity.		
19	Probably	20	Probably
21	State environmental regulation is the jurisdiction of the State Department of Ecology, whose rules are contained in Chapter 173 WAC. See http://www.leg.wa.gov/wac/index.cfm?fuseaction=title&title=173		
22	See Chapter 173 WAC. http://www.leg.wa.gov/wac/index.cfm?fuseaction=title&title=173		
23	Both state and local agencies		
24	The state Energy Facility Site Evaluation Council (EFSEC) was created to site energy facilities subject to size limitations set out in statute. See Title 80.50.020(14)(a thru e) RCW for a description of jurisdictional energy facilities. By statute, EFSEC has siting jurisdiction for large-scale plants as defined above. For facilities below these size limits, the local jurisdictions are responsible for siting of such plants. Each jurisdiction will follow its own rules or procedures.		
Wisconsin			
Scot Cullen, Chief Engineer, Gas and Energy Division, Public Service Commission of Wisconsin			
5	Yes. Wholesale merchant plant generation is allowed in Wisconsin under Wis. Stat. § 196.491. Under that statute, any Wholesale Merchant Plant generating facilities 100 MW or larger are subject to Public Service Commission approval for siting purposes. Also, WI Administrative Code Ch. PSC 119 provides rules for interconnection of distributed generation facilities up to 15 MW. However, Merchant Plant Generators are not allowed to provide public utility service at retail. The legality of any retail service supplied directly from the micro-grid would depend on whether that direct service constituted "public utility service" under Wis. Stat. § 196.01.		
6	No. Whether any retail service provided by the independent company constituted "public utility service" would be a determining factor as to the legality of the operations.		
7	The law is unclear on this point. In addition to the Commission siting approval required for merchant plants 100 MW or greater, there is the issue of whether any direct service to be provided by the micro-grid operator would constitute public utility service that would be prohibited. Size of the operation may be a factor but that determination would be subject to the facts of each situation.		
8	Wholesale merchant plants regardless of size are legal in Wisconsin. Interconnection with the transmission grid is subject to the requirements of the Midwest Independent Transmission System Operator (MISO).		
9	No. Again, the issue would be any provision of retail service and whether that constituted a "public utility" offering.		
10	See #7 above.		
11	Yes, Wisconsin electric public utilities have unique service territories. Distributed generation facilities are allowed to interconnect to the electric grid. The nature of any retail service provision from the micro-grid could be an issue as described in earlier questions above.		
12	Yes	13	Yes
14	Yes	15	Yes
16	Yes	17	Not sure
18	If the provision of service to the end-use customer constituted "public utility service" under WI Stat. § 196.01, that service would be subject to Commission jurisdiction and, as such, would probably not be allowed because "retail competition" for electric public utility service is not allowed under Wisconsin law. To the extent such service was determined not to be "public utility service", interactions between the micro-grid company and the customer would be subject to the consumer protection regulations of the WI Department of Agriculture, Trade and Consumer Protection.		
19	Not sure	20	Probably not
21	No		
22	No		
23	Both state and local agencies		
24	The threshold for Public Service Commission jurisdiction for siting non-utility generation is 100 MW.		
Wyoming			
Ruth Hobbs, Deputy Director, Public Service Commission			

5	If the micro-grid owners as a group were identical with the group receiving the distribution level service, the micro- grid would not be a public utility and it would not be regulated by the PSC. The answer would be the same if the micro-grid were interconnected with the serving utility at distribution voltage for purposes of receiving backup power. If it resells power from the utility, it would have to receive permission from the utility to resell power. If the entity were not owned by those it served, it would be providing power "to or for the public" [even if only one non-owner received service] and it would be a public utility regulated by the PSC under W.S. § 37-1-101. If the entity were a public utility, it would have to seek a certificate of public convenience and necessity from the PSC and could expect some opposition from the utility already certificated in the area. Wyoming PSC Rule 246, W.S. § 37-1-101(a), Phillips Petroleum Co. v. PSC, 545 P. 2d 1167 (WY. 1976).		
6	An entity which would "own, install and maintain" a micro-grid would be a utility subject to PSC regulation. It would not matter who hired the entity to do the work. W.S. § 37-1-101(a) [the operative language is "every person that owns, operates, leases, controls or has power to operate, lease or control"].		
7	No, the size listed and nature of the defined micro-grid does not matter in the analysis. We note that the size of the defined micro-grid would make it well beyond the limits of Wyoming's net metering laws (q.v., W.S. §§ 37-16-101 through -104).		
8	If the micro-grid were interconnected with interstate transmission lines, this would be controlled by FERC. If it merely interconnected at a transmission voltage level to a local utility, that could be a matter for state regulation. It depends on the facts of the individual case. W.S. § 37-1-101.		
9	No		
10	No		
11	The WY entity most closely fitting your description of a micro-grid is Willwood Light & Power, located south of Powell, WY. It is a true cooperative, owned and operated by 64 customers and certified as a public utility that purchases power in the wholesale market. However, this utility has its own certificated territory, is not an island within a larger utility, has one interconnection point, does not provide power into the grid and has no generating capability. All public utilities in this state have certificated territories. There are provisions for dually certificated territory, but the utility that holds a certificate for an area has the right to intervene and contest the certification of another utility wishing to serve customers within its certificated territory. Municipal electric utilities in WY are not subject to PSC regulation within their corporate limits. They pose special challenges in the case of annexation of new territory and otherwise as they are also franchising authorities for public utilities.		
12	Yes	13	Probably not
14	Yes	15	Yes
16	Yes	17	Yes
18	There are no rules or regulations explicit to micro-grids. Wyoming does not have district heating companies. If "energy service companies" are defined as competitive suppliers in a partially deregulated retail electric commodity market, Wyoming has none of these entities either.		
19	Yes	20	Probably not
21	Small generation units do not have special regulations nor are exempted from any environmental requirements pertaining to generation.		
22	No, they do not have special status		
23	Both state and local agencies		
24	Regulatory requirements are same at the state level. County rules could vary.		
Comments: WY's demographics do not lend themselves to being a leader in small distributed generation technology applications, although WY participates in regional and national initiatives to enhance the availability and reliability of electric service to its citizens and to the Western Interconnection in general.			

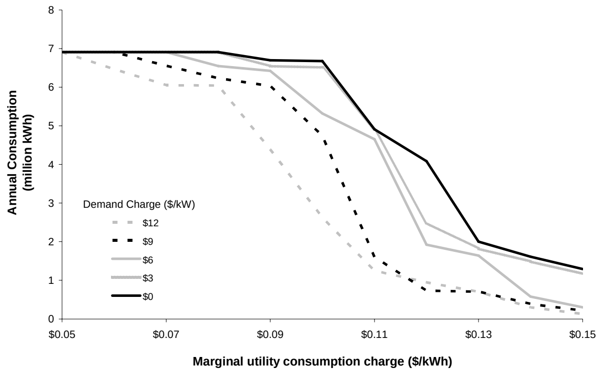
Appendix C. Rate-setting and Customer Behavior

The figures in this appendix were created using the methodology discussed in Chapter 4. The analysis discussed in Chapter 4 was conducted for four different scenarios: a high-rise and hospital complex in both Minneapolis, MN and San Diego, CA. Multiple scenarios were modeled in an effort to make the results of the analysis more generalizeable and robust; these particular scenarios were chosen because they capture most of the variation of the results from chapter 2.

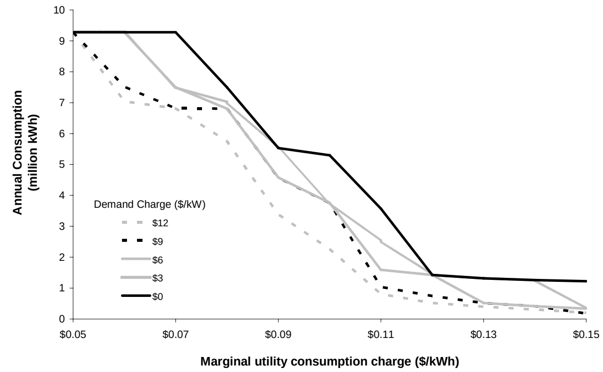


Figures C-1 a-d. Impact of consumption and demand charges on micro-grid consumption behavior for four different scenarios. Contours represent the percentage of annual power consumption by the customer-generator from the utility that occurs during peak periods. When prices are low, it is not cost-effective to install or operate a micro-grid. As prices increase, the micro-grid becomes more profitable, and customer-generators consume proportionately less power from the utility during peak periods.

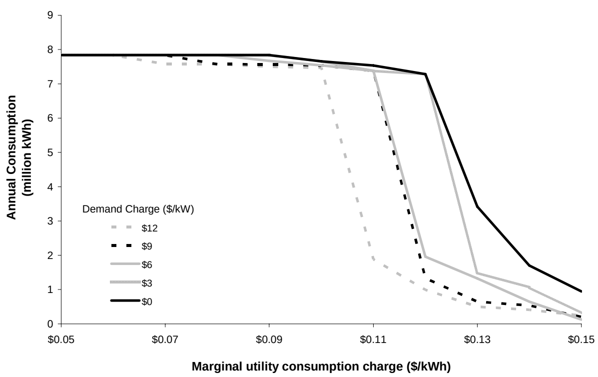
C-2a. Minneapolis high-rise



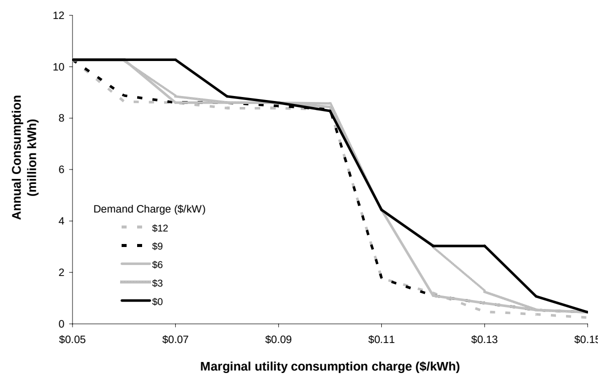
C-2b. Minneapolis hospital



C-2c. San Diego high-rise



C-2d. San Diego hospital



Figures C-2 a-d. Micro-grid demand for utility electricity (kWh) as a function of utility consumption and demand charges for 4 different scenarios. These plots reflect long-term, not short-term, installation and operational decisions by the customer-generator.

C-3a. Benefits associated with distributed generation

	What are the Benefits?	Policy Intervention Requirement[1]	Economic Magnitude[2]	Analytic Tractability[3]
1	Support of RPS Goals	Likely	Medium	Difficult
2	Mitigation of Market Power	Unlikely	Medium - Low	Medium
3	Airborne or Outdoor Emissions	Likely	Medium	Medium
4	Reduced Security Risk to Grid	Likely	High - Low	Difficult
5	Reliability and Power Quality (Distribution System)	Likely	Medium -Low	Medium
6	Voltage Support to Electric Grid	Unclear	Low	Medium
7	Enhanced Electricity Price Elasticity	Unclear	Medium -Low	Medium
8	NIMBY Opposition to Central Power Plants and Transmission Lines	Likely	Low	Difficult
9	Land Use Effects	Likely	Low	Difficult
10	Avoided T&D Capacity	Likely	High- Medium	Medium
11	System Losses	Likely	Medium-Low	Medium
12	Combined Heat and Power/ Efficiency Improvement	Unlikely	High	Easy
13	Consumer Control	Unlikely	Low	Difficult
14	Lower Cost of Electricity	Unlikely	High- Medium	Easy
15	Consumer Electricity Price Protection	Unlikely	Medium -Low	Medium
16	Reliability and Power Quality (DG Owner)	Unlikely	Medium	Easy
17	Ancillary Services	Likely	High-Medium	Medium

C-3b. Costs associated with distributed generation

	What are the Costs?	Policy Intervention Requirement[1]	Economic Magnitude[2]	Analytic Tractability[3]
1	Utility Revenue Reduction	Likely	High	Medium
2	Standby Charges	Likely	Medium	Medium
3	Incentives for Clean Technologies	Likely	Medium	Easy
4	Noise Disturbance	Likely	Low	Difficult
5	Indoor Emissions	Likely	Low	Difficult
6	Maintain System Reliability and Control Distributed Resources	Likely	High-Low	Difficult
7	Emissions Offsets	Unclear	Medium	Easy
8	Airborne or Outdoor Emissions	Unclear	Medium	Medium
9	DER Fuel Delivery Challenges	Unclear	Medium-Low	Easy
10	Equipment	Unlikely	High	Easy
11	Interconnection (system studies and upgrades)	Unlikely	High-Low	Easy
12	Fuel	Unlikely	High	Easy
13	Maintenance	Unlikely	High	Easy
14	Insurance	Unlikely	Low	Easy
15	Exemptions from Cost Responsibility Surcharges	Regulation in place	High	Easy

Priority Benefits for R.04-03-017

N
otes: 1) The possibility of markets developing that internalize the cost without policy intervention; 2) Relative size of the cost; 3) the possibility and ease of quantifying the cost (method, model, and data availability)

Figure C-3 a-b. In response to the California Public Utilities Commission new rulemaking, R.04-03-017, the California Energy Commission prepared an assessment of the costs and benefits that distributed resources provide. Figures C-3 a) and b) present the costs and benefits, as well as a preliminary assessment of their significance to the PUC. These figures are reproduced directly from "Distributed Generation Costs and Benefits Issue Paper" by Mark Rawson (2004), pgs. 14-15.