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Are US utility standby rates inhibiting diffusion of customer-owned generating systems?

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Abstract

New, small-scale electric generation technologies permit utility customers to generate some of their own electric power and to utilize waste heat for space heating and other applications at the building site. This combined heat and power (CHP) characteristic can provide significant energy-cost savings. However, most current US utility regulations leave CHP standby rate specification largely to utility discretion resulting in claims by CHP advocates that excessive standby rates are significantly reducing CHP-related savings and inhibiting CHP diffusion. The impacts of standby rates on the adoption of CHP are difficult to determine; however, because of the characteristically slow nature of new technology diffusion. This study develops an agent-based microsimulation model of CHP technology choice using cellular automata to represent new technology information dispersion and knowledge acquisition. Applying the model as an *n*-factorial experiment quantifies the impacts of standby rates on CHP technologies under alternative diffusion paths. Analysis of a sample utility indicates that, regardless of the likely diffusion process, reducing standby rates to reflect the cost of serving a large number of small, spatially clustered CHP systems significantly increases the adoption of these technologies.

Keywords: Distributed generation; Agent-based model; New technology

1. Introduction

While large combined heat and power (CHP) systems have been used for decades in industrial, hospital and university applications, recent technology innovations permit smaller utility customers to self-generate all or a portion of their own electricity onsite and to apply waste heat from the generation process for thermal uses such as space heating, water heating, and air conditioning. For customers with appropriate hourly electric and thermal loads, overall CHP system efficiency can reach 85 percent compared to a maximum of about 50 percent for the most efficient central utility generation plants and about 33 percent for the average US utility generation plant.[1] CHP systems improve the efficiency of the entire electric generation system, reduce emissions and can provide substantial reductions in utility customer energy costs.

Currently, the primary US market for new small-scale CHP technologies is the commercial sector. A 2000 US Department of Energy study found 74 Gigawatts (GW) of technically feasible potential[2] for commercial sector CHP system installations representing about 12 percent of total electric utility-owned capacity in the year 2000.

Recent standardization of utility interconnection requirements, remote monitoring/control and guaranteed service contracts are a few recent CHP market innovations that facilitate CHP installations. Emission control technologies guarantee compliance with the most stringent local requirements while CHP systems can provide improved power quality and reliability compared to grid-delivered power.

In spite of these developments, existing small US commercial sector systems probably number no more than

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[1]Overall system efficiency is the percent of generation energy input delivered as useful energy to the final user. See DOE, 2000, 2002 and 2003 for a description of CHP technologies, markets and case studies.

[2]Technically feasible potential includes installations where a majority of waste heat can be utilized with limited changes in existing building thermal energy systems (e.g., space heating).

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several thousand (Jackson, 2005; DOE, 2000) and while that number is increasing (Prabhu, 2002; NECHPI, 2005), CHP systems appear to be making only modest inroads in the market (NECHPI, 2005).

CHP proponents frequently identify high standby (or backup) rates, charged by the local utility when CHP systems are unexpectedly unavailable, as one of the primary reasons for the slow adoption of CHP systems (Jimison et al., 2004; Casten, 2003). A recent addition to the literature (Firestone and Marnay, 2005) confirms the important impact of standby rates in six New York utility service areas.

While utilities are required to determine standby electric rates based on cost, this process is complicated and sometimes inconsistent with no agreed-upon methodology. For example, state regulatory agencies require revenue neutrality[3] in designing standby rates; however, crediting CHP customers for fixed cost savings associated with generation and distribution would automatically increase the allocation of additional fixed costs to non-standby customers. On the other hand, the Federal Energy Regulatory Commission (FERC), directs utilities to incorporate utility savings associated with intermittent demands in standby rate design. Consequently, utilities typically have considerable discretion in setting standby rates for incremental service required if the utility customer's CHP-generating system is not operating.[4] This rate-setting flexibility puts utilities in the position of regulating competition from their own customers.[5] Furthermore, revenue reductions resulting from cost-based standby rates have an exaggerated impact on profits for investor-owned utilities (Weston, 2000; Moskovitz, 2000, Regulatory Assistance Project, 2000) and create rate pressure for publicly owned utilities.[6]

[3]Once rates are set, revenue neutrality requires any change in the rate for a single rate class to have no impact on revenue requirements of other rate classes.

[4]Standby rates differ by utility primarily in "demand" charges (charges for the maximum 15-min kW use in the month). Most utilities apply "ratchet" clauses that bill demand based on the maximum kW in the previous year. Standard non-CHP demand charges typically range from \$6 to \$9 per kW. Utilities who strive for revenue neutrality set standby rate demand charges as close to standard demand charges as possible so that even one unplanned 15-min system downtime in the year will recover lost revenue. One utility, in recent years, set standby rates at more than double the standard rate, which could have conceivably increased revenue from CHP customers (LIPA, 2001). More recent standby rate setting practices appear to set standby demand rates at approximately 50 percent of full demand charges using a combination of capacity and use charges (e.g, LIPA, 2004).

[5]Each utility is regulated by one or more agencies in its own state. Consequently, this description includes some generalization. The local distribution utility designs and applies standby rates and remains regulated in all US states.

[6]Adoption of CHP technologies also reduces the utility's generation, transmission and distribution assets relative to a world without CHP. In addition to the Averech-Johnson effect, which explains over-investment in capital by regulated firms, a larger asset base reduces the relative impacts of random negative influences on revenue such as weather and economic fluctuations.

An equally compelling argument, however, can be made that the slow adoption of CHP is characteristic of new technology diffusion and a long-recognized reluctance of firms to invest in energy-saving investments (Jaffe and Stavins, 1994; Jaffe et al., 2001; DeCanio, 1998).[7]

The extent to which CHP diffusion is limited by current regulatory practices as opposed to reflecting traditional new technology diffusion has important policy implications for the \$239 billion US electric industry. CHP systems can potentially offer a significant opportunity to improve energy efficiency and reduce emissions. Encouraging this resource through policy initiatives; however, requires understanding the nature of current impediments, if any, to the adoption of CHP technologies.

Unfortunately, lack of utility CHP data, nonstandard interconnection fees, revisions in standby rates over time, complicated nonlinear electric rate structures that differ by utility and many other data difficulties prevent statistical tests of these hypotheses.

The objective of this study is to develop an agent-based microsimulation model of new CHP technology diffusion that permits analysis of utility standby-rate setting practices on the adoption of these new technologies. The remainder of this paper is organized as follows: The next section provides a brief review of relevant literature. Section 3 describes the conceptual model and Section 4 presents an empirical model specification. Section 5 describes analysis results. The final section provides a summary.

2. Relevant literature

Empirically assessing the impacts of standby rates on the diffusion of new CHP technologies requires a model structure that can represent (1) detailed CHP technology characteristics, (2) individual agent hourly electric and thermal energy use heterogeneity, (3) agent decision criteria heterogeneity, (4) detailed non-linear utility rate structures and (5) the endogenous spread of information among agents and agent knowledge accumulation.

The agent-based model developed in this study extends traditional economic microsimulation-modeling to accomplish these tasks by including bounded rational agent investment behavior and an agent-based process to represent agent interactions and the dissemination of new technology information. Relevant literature antecedents and modeling considerations are described in the remainder of this section.

2.1. Microsimulation models

Microsimulation approaches have been applied to accommodate the first four modeling issues above in

[7]Lee (2003) and others argue that customer-sited generation yields limited value relative to attributes of grid-provided power and is likely to serve only niche applications. As indicated in a later section, the analytical approach developed in this study accommodates CHP attribute values as positive and negative costs relative to grid power.