Retail Electricity Deregulation: Prospects and Challenges for Dynamic Pricing and Enabling Technologies[1]

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I. Introduction

The past 15 years have seen dramatic, but sporadic, institutional change in the electric power industry. These changes have occurred at the federal level, taking the form of both legislative change (*e.g.,* Energy Policy Act of 1992, Energy Policy Act of 2005) and regulatory change (*e.g.,* FERC Orders 888, 889, 2000, etc.). Institutional change in the form of both legislative and regulatory change has also occurred at the state level (regulatory restructuring in over 20 states since 1996), reflecting the layered nature of regulation and regulation's split jurisdiction in this industry.

This period of layered institutional changes, and their interaction with economic growth, technological change, and other economic factors, has resulted in a period of regulatory limbo, with no clear policy vision for regulation, deregulation, or restructuring in the electricity industry. Optimistic expectations from the 1990s restructuring changes have not been met, and rising consumer concerns about high fuel costs are leading to state-level decisions to delay restructuring, or to continue retail price caps in restructured states. Some observers proclaim electricity restructuring a failure, but in the face of economic growth and technological change, the traditional regulatory model is itself obsolete. Furthermore, environmental issues and the opportunities afforded by digital communication technology to manage electricity use and enhance its efficiency make it all the more important to think differently about the problem of regulation.

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Yet the electric power industry, the backbone of our modern, technology-rich lives, is the most technologically backward industry in the country, an analog relic of the early 20th century. Similarly, regulatory institutions have not adapted to these exogenous technological changes, resulting in regulated investments and service offerings that perpetuate this analog equilibrium.

This paper focuses on the interaction between technology and state-level retail regulation, particularly with respect to retail pricing. Specifically, the development of digital communication technology in the past 20 years has increased the possibility of offering dynamic pricing (particularly time-based rates) and differentiated products, even to residential customers. The technology that enables this is the two-way programmable communicating thermostat and digital advanced metering infrastructure. Making that outcome a reality requires not just technological change, but also institutional change, including the removal of regulatory barriers to pricing and product differentiation. Another important institutional change is informal; customer culture would have to adapt over time to different ways of buying and consuming power.

The relationship between institutional change and technological change in electric power has been a specific manifestation of federalism. Spurred by energy efficiency concerns and the potential for market competition, Congress passes new energy-related legislation that induces reactive change at the state level by placing new requirements or restrictions on electric utility transactions. State regulatory institutions then absorb those changes. Rarely has the direction of institutional change been state-to-federal.[2]

One important applied research activity for creating the knowledge to inform these technology-induced institutional changes is the pilot program or demonstration project. Over the past 35 years several projects have explored how consumers of different types respond when facing dynamic pricing; increasingly, such projects also investigate the interaction of dynamic pricing and digital technology.

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[2] However, notable state policy innovations in electricity have influenced federal institutional change. For example, California's recent PUC and Energy Commission proceedings to implement system-wide advanced metering infrastructure and programmable controlling thermostats, based on research discussed later in this paper, occurred before and informed the smart metering provisions of the Energy Policy Act of 2005. Another example is the regulatory procedure for setting small generator interconnection standards in Texas, which was later adapted to establishing the federal small generator interconnection standards.

After providing an industry and regulatory overview (Section II), this paper gives a brief analysis of dynamic pricing (Section III), and then focuses on research in residential customer behavior in the presence of dynamic pricing and enabling technologies (Section IV). Section IV also reports preliminary results from a project designed specifically to test hypotheses about the effects of choice in retail pricing and technology for automating responses to price signals. This research indicates that residential customer response to dynamic pricing is significant enough to have beneficial system reliability effects, and the use of digital technologies can forestall the need for capital investment in generation and wires capacity.

However, these enabling technologies change both the policy environment and the nature of the research questions. They create a network with highly distributed intelligence, whereas before physical control and economic response were much more highly centralized. The conclusion (Section V) suggests some dimensions of a conceptual and theoretical framework for analyzing individual behavior and regulatory institutions in this highly decentralized environment.

II. The Nature of the Industry and Its Economic Regulation

A. Industry Overview

The physical supply chain in electricity has three parts: generation, transmission and distribution. Generation involves using a fuel to drive a turbine that generates electric power. Transmission and distribution wires transport that power from the generator to end-use customers. For both engineering and economic purposes, transmission and distribution are the same, except that transmission occurs over longer distances and therefore requires higher voltage capability. The economic value chain in electricity focuses more on the transactions among the different steps in the supply chain, and thus adds a retail and customer service component to the physical description of the supply chain.

Despite advances in technology, the generation of electricity remains fundamentally the same as it was a century ago: rotating a magnet inside a coil of wire. The actual rotation of the magnet can come from a variety of sources including the generation of steam, falling water, or expanding gas. There are three general types of generators: baseload, peaking, and load-following or cycling. The most expensive to build but most efficient ones are called baseload generators and cover the greater part of electricity demand. Peaking units, while cheapest to build, are the most expensive to run. These typically supply the electricity in excess of what the baseload generators supply. The load-following or cycling unit operates when demand is beyond what baseload generators supply, but not yet at the point where peaking units must be used. It falls between the two types of generators in terms of cost of construction and operation (Standard & Poor's 2006, p. 13).

Because storing electricity is prohibitively costly given existing technology, the network must have the capability to generate electricity and then to transport it in real time. Electricity is delivered to consumers through transmission lines and distribution facilities. Utility companies use high voltage power lines to transmit electricity over long distances; then transformers reduce the voltage as electricity passes from transmission lines to distribution lines before reaching the consumer (Standard & Poor's 2006, p. 13).

Electricity markets consist of the sale and distribution of electricity to end users that include industrial, commercial, and household customers. In 2005, total revenue from sale of electricity to end-use customers totaled $245 billion. Electricity to households accounted for about 51 percent of total sales at $124.9 billion. The percentage of use by value in the US can be described as follows: households 51 percent, industrial 23.7 percent, commercial 22.9 percent, other 2.4 percent. US markets are actually forecasted to decelerate. The US compound annual growth rate (CAGR) of 4.5 percent from 2001-2005 is expected to fall to 3.6 percent for the 2005-2010 period, driving US market to a value of $292.7 billion by 2010; this figure is a 19.5 percent increase from 2005 revenues. US markets grew 2.5 percent in 2005 to reach 3810.3 billion kilowatt hours (kWh) . Over the five-year period from 2001-2005, the US CAGR for volume consumed was 1.9 percent. The US market volume is forecasted to reach 4166.5 billion kWh in 2010 for an increase of 9.3 percent since 2005. CAGR for this predicted market volume will be 1.8 percent for the period 2005-2010 (Datamonitor 2006, pp. 7-11).

Of over 3170 power utilities providing retail service in the United States, 239 are investor-owned utilities, 2009 are publicly owned utilities, 912 are consumer owned cooperatives, and 10 are Federal utilities. Despite being large in number – representing about 63 percent of all electric utilities in the US – publicly owned utilities serve a small part of overall demand, only about 10 percent of generating capabilities, 15 percent of retail sales, and 14 percent of total revenue. Cooperatives are typically found in rural areas where it has been determined to be uneconomical to transmit power from other regions. Faced with no service, consumers established cooperatives to provide power and electricity. These utilities make up 29 percent of all US utilities and represent around 4 percent of generation capability. In addition, cooperatives make up around 9 percent of sales and revenue. Investor-owned utilities (IOU) make up a mere 8 percent of the total number of electric utilities, but supply 75 percent of the generating capacity and 75 percent of retail sales and revenue (EIA Overview).

In 2006, residential consumers accounted for 42.7 percent of the revenue for investor-owned utilities, commercial 38.3 percent, industrial 18.8 percent and 0.2 percent to other end users. Industrial customers are in a position to negotiate a lower price – cogeneration and relocation are options – and pay the lowest rates. Commercial and residential consumers are not in a similar position and thus pay a higher rate (Standard & Poor's 2006, pp. 13-14).

The United States accounts for 24.6 percent of global market value in electricity. Currently in the US, the major IOUs are American Electric Power, Southern Company, FPL Group, and Duke Energy Corp. Of the US electricity market, American Electric Power holds the greatest market share at 5.7 percent, followed by Southern Company with 5.2 percent, FPL Group at 2.8 percent, and Duke Energy Corp at 2.2 percent. Most of these firms have both regulated subsidiaries, where they serve customers in their native service territory, and unregulated subsidiaries selling the electricity they generate through organized wholesale markets and through long-term contracts. The remaining 84.1 percent of the market is accounted for by other firms; the fragmented market share reflects the regional service territory aspect of the regulated utility (Datamonitor 2006, pp. 12-13).

B. Electricity Regulation: Historical and Theoretical Background

The electricity industry is the last remaining industry to be regulated fully as a public utility. This regulation has four elements: control of entry, price fixing, prescription of quality and conditions of service, and the imposition of an obligation to serve (Kahn 1988, Vol. I p. 3). The regulated firm has typically been a vertically-integrated, private, investor-owned utility.

The traditional structure and regulatory environment in the electricity industry are due primarily to scale economies; thus the electricity industry has existed over the past century as a natural monopoly. The defining characteristic of natural monopoly is declining average costs over the relevant range of demand; this characteristic is known as economies of scale for a single-product firm and subadditivity of cost in a multi-product firm. The primary source of this characteristic is the high fixed cost required to build the infrastructure necessary to serve customers; low marginal cost is not necessary for the existence of economies of scale, but empirically the combination of high fixed cost and low marginal cost has characterized large-scale central electricity generation since the early 20th century.[3] In a system with high fixed costs and capital requirements, it is inefficient to have similar utilities providing similar services in similar regions, for instance two distribution companies delivering electricity within a city.

The electric industry's technical development as a natural monopoly can be traced back to the 19th century. For example, between the years of 1887 and 1893, twenty-four power companies were established in Chicago. With overlapping markets, the competition was high and investment was largely duplicative. Samuel Insull of the National Electric Light Association resolved this problem in 1898 by purchasing all twenty-four power stations, establishing a monopoly. The creation of a monopoly led fairly directly to regulations on monopoly profits, and while some pushed for competitive pricing, Insull advocated profits above the competitive level

[3] For a more thorough discussion of the technical aspects of natural monopoly, see Kahn (1988), Vol. II pp. 119-125. For an illustration of how Samuel Insull's turbogenerators created economies of scale in the early 20th century, see Platt (1991), pp. 212-213.

to enable the regulated monopoly to invest in infrastructure so it could serve all customers on demand (Stoft 2002, p. 6; Hirsh 1999, p. 14).[4]

Since the beginning of commercial electric power in the 1880s, electricity has been sold to end-use customers as a bundled good – energy and wires – through vertically integrated firms. It also has been regulated as a bundled good, both by regulatory fiat and, up to a point, by technological necessity. That regulation has largely taken place at the state level, starting with New York and Wisconsin in 1907 (Hirsh 1999, p. 21). By 1920 most states had established state public utility commissions to regulate electric utilities, instead of relying solely on municipal franchises.

Under regulation, utilities received exclusive franchises for specific service territories. This franchise generally carries with it an obligation to serve all present and future customers in the service territory at a reasonable price. The obligation to serve persists to this day as a fundamental characteristic of the monopoly franchise and has served to eliminate possible competition for utilities, including competition from new technologies for distributed generation or from retail energy service providers. Basing the rates that customers pay on cost recovery is one of the consequences of the obligation to serve (in combination with rate-of-return regulation). This focus on cost recovery in rates often provides an obstacle to the evolution of market-based retail electric pricing, because instead of considering the value created for customers it emphasizes only the cost of providing customers with a particular type and level of service.

In 1920 the federal government began regulating the industry through the Federal Power Act, with the original objective of licensing hydroelectric power plants while still allowing for waterway navigation. It received substantial amendments in the 1930s, when Congress granted the Federal Power Commission (the forerunner of today's Federal Energy Regulatory Commission) regulatory jurisdiction over the pricing of interstate power transmission. Congress also added the Public Utility Holding Company Act (PUHCA) in 1935 to regulate the ownership structure of IOUs, after holding company acquisition of many local utilities led to some financial

[4] Jarrell (1978) analyzes the process by which state PUCs were established and finds support for the argument that electric utilities welcomed and even encouraged the development of state-level economic regulation, rather than the public-interest theory that is more often used to explain the formation of regulation.

abuses (Bosselman et. al. 2000, p. 716). By the end of the 1930s, a federal policy of national electrification had crystallized, and construction of plants, wires, and substations to meet that objective commenced.

The 1940s to 1960s was a period of massive investment to meet the policy of national electricification, induced by the regulated rate of return that utilities earned on those investments. By late 1960s, though, investment slowed and so did the operating efficiency of new generation, which hit a plateau of approximately 33 percent in the early 1960s (Hirsh, 1999, Figure 3.1, p. 57). By this time, though, the industry had largely achieved the federal policy objective of national electrification.

During the 1960s utilities also began constructing nuclear power plants, seen as clean and low-cost generation once the plant was built. During the 1970s, however, nuclear power plant capital expenditures escalated because of expanding construction times associated with complicated, idiosyncratic nuclear plant construction (Hirsh 1999, p. 173). Utilities borrowed to fund these expenses, and by the inflationary period of the early 1980s, interest payments on those debts became prohibitive and politically unpopular, as costs were passed on to consumers (Hirsh 1999, p. 174). California and Illinois experienced particularly high construction costs and debt levels, and some Northeast states also saw these high costs flow through to higher retail rates to end-use customers.

C. Institutional Change: Regulatory Restructuring, 1978-2007

Large, centralized generators integrated with transmission and distribution systems have been able to realize significantly lower operating costs than smaller generators for most of the past century. Nonetheless, several factors have facilitated the shift to a more competitive market over the years. First, technological advances have led to more efficient gas-fired generators – compared to coal fired generators – and high-voltage transmission lines providing transport of electricity over greater distances consequently give consumers more choices in power suppliers. Second, increases in retail electricity prices to residential and industrial consumers have led government officials to reconsider the traditional regulatory system. Finally, as a result of the

Public Utilities Regulatory Policies Act of 1978 (PURPA), the rise of generators using renewable energy sources showed that there were reliable sources of power other than large-scale central generation owned by a vertically-integrated firm.

The 1970s saw rising fuel prices and increasing attention to environmental concerns, including air and water quality concerns associated with fossil fuel use. Combined with nuclear cost overruns, these issues created pressures for increased competition in the electricity industry. PURPA, passed in 1978 as part of President Carter's National Energy Plan, forced the competition issue with respect to electricity generation. In addition to provisions encouraging energy efficiency, Section 210 of PURPA authorized FERC to require utilities to purchase power from "qualifying facilities" (QFs), which were either small generation facilities using non-conventional fuels or cogeneration facilities using conventional fuels that recycled their waste heat. (Bosselman et. al. 2000, p. 718; Hirsh 1999, p. 87). The consequences of PURPA were largely unintended, both negative (long-term QF contracts at high prices, for example, in California) and positive (breaking the entry barrier in generation).[5]

At the same time, combined cycle gas turbine (CCGT) generation technology developed outside of the industry, and some aspects of PURPA decreased the economies of scale in power generation. An exogenous technological change thus changed both the economics of generation and the economics of the vertically integrated firm; it was no longer the case that the only profit maximizing organizational structure in the industry was the vertically integrated firm with large-scale central generation.

The next meaningful institutional change at the federal level was the Energy Policy Act of 1992, which dramatically expanded competitive incentives and dynamics and created the potential for wholesale electricity markets. EPAct 1992 acknowledged PURPA's unintended consequences and liberalized wholesale trade of the electricity commodity at the federal level. Heretofore, utilities only traded to meet emergency needs, which meant that few high-voltage interconnections existed among service territories. This legislative change led to nascent

[5] For a thorough and fascinating analysis of the political process to get PURPA passed, see Hirsh (1999) Chapter 4.

wholesale markets, especially in areas like the mid-Atlantic region and New England, which had pre-existing power pool operations platforms to facilitate those emergency trades.

Economic theory suggests that such liberalization would lead to competition, which would lead to lower electricity commodity prices, leading to lower retail rates as those lower prices were passed through to consumers. This prospect was particularly appealing in states with cost overruns from nuclear plant construction and expensive QF contracts under PURPA; thus the first states to pursue state-level restructuring were Pennsylvania, Illinois, Maine, Massachusetts, and California. Other states soon followed (including New York and Maryland); currently 20 states and the District of Columbia have passed restructuring legislation.

Over half of the states in the United States have embarked on so-called deregulation initiatives, which retain a substantial dose of regulation, but of a different form from the traditional regulatory treatment of the vertically integrated industry. Some states, like Texas and Pennsylvania, successfully used their restructuring to enable utilities and merchant generators to create value for consumers. Others, like California, encumbered their market design process with so many political constraints that needed investments in capacity were deterred and consumers suffered substantial harm. This patchwork of experiences, in combination with the discovery of abusive trading practices by Enron and other market participants, reduced the liquidity of wholesale markets and contributed to a debt crisis for energy companies.
In most states the restructuring legislation focused on some form of wholesale unbundling (either functional separation or structural divestiture). Retail competition was delayed as part of the political bargain to induce utilities to agree to the restructuring proposal. For example, Pennsylvania's retail rate caps phase out over 10 years and have not yet been removed; Maryland's phased out over six years and expired in July, 2006, and Illinois' rate caps phased out over 10 years and expired in December, 2006. Another part of the political bargain was the payment of stranded costs to utilities, to compensate them for costs they had borne and generation investments they had made in anticipation of rate recovery over the 30-plus years during which the assets depreciated. Utilities bargained for these stranded costs and received them in addition to any revenue they earned from selling generation facilities.

A series of bad experiences and events have caused the national move toward restructuring and competition to stall. The California electricity crisis of 2000-2001 brought home two very painful lessons about restructuring and institutional change: restructuring in a complex network industry is harder than neoclassical theory would predict, and institutions matter. In this case, the institutions are the market and regulatory institutions comprising the market design that is largely unnecessary in more organic market processes.

The most recent formal institutional change was the Energy Policy Act of 2005, passed by Congress in August 2005. The most sweeping energy legislation since the late 1970s, EPAct 2005 ranged from subsidies for clean coal technology R&D to changing Daylight Savings Time. Its electricity provisions included support for demand response and smart metering policies, which will be discussed in Section IV.

III. Dynamic Pricing for Residential Customers

Electric loads follow patterns that vary over the day and the season. The daily variation is generally low (off-peak) demand overnight, a rise in demand in the morning to a shoulder period through the day, a high-demand period in the late afternoon and early evening (exacerbated by air conditioning on hot days), and a return to a lower, shoulder demand in the evening. In the absence of any price variation over the course of the day, this pattern repeats daily. The seasonal dimension depends on whether consumers in the area use electricity for heat or cooling, and the extremity of the climate variance.

The cost of generating and distributing electric power service to end-use customers varies over the day and across seasons; cost increases during the day are largely driven by quantity demanded approaching supply capacity. The fixed retail rates that customers have faced under retail regulation mean that the prices individual consumers pay bear little or no relation to the marginal cost of providing power in any given hour. Facing fixed prices, consumers have no incentive to change their consumption as the marginal cost of producing electricity changes. The consequences of this disconnect of cost from price transcend inefficient energy consumption to include inappropriate investment in generation and transmission capacity. Dynamic pricing provides a way to rectify that disconnect.

George and Faruqui (2002, p. 2) define dynamic pricing as “any electricity tariff that recognizes the inherent uncertainty in supply costs.” Dynamic pricing can include time-of-use (TOU) rates, which are different prices in blocks over a day, based on expected wholesale prices, or real-time pricing (RTP) in which actual market prices are transmitted to consumers, generally in increments of an hour or less. A TOU rate typically applies predetermined prices to specific time periods by day and by season. RTP differs from TOU mainly because RTP exposes consumers to unexpected variations (positive and negative) due to demand conditions, weather, and other factors. In a sense, fixed retail rates and RTP are the endpoints of a continuum of how much price variability the consumer sees, and different types of TOU systems are points on that continuum. Thus RTP is but one example of dynamic pricing. Both RTP and TOU provide better price signals to customers than current regulated average prices do. They also enable companies to sell, and customers to purchase, electric power service as a differentiated product.

The evidence of the past 20 years suggests that customers respond in a variety of ways to dynamic pricing, even when they have only rudimentary enabling technology (Kiesling 2007a, 2007b). This evidence suggests that a substantial, new set of value propositions exists at the intersection of dynamic pricing and new consumer-facing technologies. While most existing programs and studies focus primarily on consumer behavior in the face of dynamic pricing, the focus is shifting to the question of the symbiosis of pricing and technology: with the enabling technology, do customers respond differently to dynamic pricing?

Several utilities have implemented some limited market-based pricing programs. Although small and exploratory, these have generated positive results that will be useful as more utilities move to market-based pricing. None of these programs implements true dynamic pricing, though; instead they are “demand response” programs that use time-of-day price changes to give customers incentives to shift load. Nor do most of them explore the effects of digital enabling technology beyond simple interval meters. That said, these experiences do indicate how powerful price incentives can be for consumers, and how dynamic pricing contributes to a reliable, efficient electricity system.

The benefits of implementing dynamic pricing are extensive and widely agreed upon.[6] Dynamic pricing makes the value of their energy use transparent to consumers, and particularly benefits consumers whose consumption is flexible. That flexibility and response to price signals leads to market power mitigation, because active demand disciplines the ability of suppliers to raise prices. Consequently, dynamic pricing leads to lower wholesale electricity prices, better capital utilization and load factors, and reduced needs for additional generation and transmission investment. In this way dynamic pricing leads to long-term cost reductions relative to fixed, regulated rates. Dynamic pricing also promotes a more equitable distribution of those costs, because it prioritizes electricity consumption according to value and does a better job of reflecting the actual costs of service.

Increased reliability is one valuable benefit of dynamic pricing. Although reliability is traditionally treated as a supply issue, it is also a demand issue. Active demand response to price signals inherently acts to moderate strains on the entire system when that system's use is properly priced. The connection of dynamic pricing and demand response to transmission networks is the reduction of peak-period consumption. Customer load reduction can serve long-run reliability functions, by reducing the likelihood of transmission bottlenecks and insufficient generation. Reliability in the existing regulated model requires the utility to have (or have access to) sufficient generation capacity to satisfy *all* demand at *all* hours of the day – this high capital requirement is one consequence of the regulated "obligation to serve" aspect of the government-granted monopoly franchise. The requirement to build to meet peak is expensive, but the failure to use dynamic pricing to reduce those peaks makes the capital requirement even higher.

One important benefit of dynamic pricing is its promotion of innovation. The transparency of price signals that better reflect actual costs gives consumers incentives to seek out novel products and services that better enable them to manage their own energy choices and make decisions that better meet their needs. This incentive induces entrepreneurs to invest their capital in providing

[6] For a more thorough discussion of the benefits of dynamic pricing, see Kiesling (2007a).

products and services that consumers may choose. Competition for the business of active, engaged, empowered retail customers would drive innovation in end-use technologies, such as integrated home gateways that allow homeowners to manage their home theaters, stereos, appliances and heating/cooling.

A third benefit of dynamic pricing is risk management. Dynamic pricing emphasizes the information content of prices, an aspect of prices that frequently gets overlooked in political debates. Prices communicate valuable information about relative value and relative scarcity, and when buyers and sellers make consumption and production decisions based on those signals, they communicate further information about value and scarcity. This information transmission and aggregation process is at the core of the efficiency of outcomes generated through market processes. An important policy distinction arises between customers being *required* to see hourly prices, and customers having the *opportunity* to see hourly prices. Requiring real-time pricing would both contradict the idea of choice and expose some customers to more price risk than they might choose voluntarily.

Dynamic pricing would create an opportunity for consumers to choose how much of that price risk they are willing to bear, and how much they are willing to pay to avoid by laying it off on some other party (such as a retailer). Although regulated rates have provided financial insurance, they do not fully communicate the cost of insuring different types of consumers against different types of price risks. They also fail to reflect the different degrees to which diverse consumers might choose to be insured. Customer heterogeneity means that they have, among other things, different risk preferences, and different willingness to pay to avoid price risk. Dynamic prices allow the electricity commodity price and the financial insurance premium components of the price to be unbundled, and to be offered separately to customers. This unbundling would enable more efficient pricing of the financial risk, leading to better risk allocation.

Several studies have estimated the value of transforming the electric power network to incorporate more active demand and digital technology. A Government Accountability Office study (GAO 2004) reported estimates of the overall economic value of more active electricity demand and ability to respond to price signals. These estimates of benefits range from $4.5 billion to $15 billion annually (GAO 2004, Table 1, Table 2).

In 2004 Rand performed an analysis of the benefits of the GridWise Initiative, a national initiative to modernize the electric power network using communication technology, building and appliance automation, market processes, and contracts. The GridWise Initiative emphasizes the use of technology to communicate information, including price signals. Rand's estimate of the benefits of GridWise provides evidence on the value of dynamic pricing and enabling technologies. Projecting estimates forward to 2025, the Rand study compares a phased-in GridWise transition to the Energy Information Administration's Annual Energy Outlook projections over the same period. The GridWise features modeled include peak load reduction due to dynamic pricing; capacity investment deferral for generation, transmission, and distribution; reduced operating expenses; improved power quality and reliability; and improved efficiency. The analysis uses ranges of estimates of these variables to arrive at aggregate discounted benefits from $32 billion to $132 billion. Their nominal estimate of the net present value of benefits over 20 years is $81 billion (Rand 2004, p. 28).

IV. The Symbiotic Nature of Dynamic Pricing and Enabling Technologies: Evidence

A. Enabling Technologies for Residential Demand

Customer response to price signals requires that consumers and/or their devices know in advance what price will apply at what time, and to which service, if they purchase a variety of services from their retailer. This communication need not be digital or automated direct communication of prices to devices (it could take the form of a phone message, for example); however, two-way digital communication technology opens up the potential for direct communication with devices. Such potential gets around the usual argument that residential consumers do not want to have to think about their electricity consumption or undertake much effort to control and manage their electricity use. Two-way digital technology also changes the shape of the demand curve, making it more price elastic, which can have beneficial effects on conservation, on average (wholesale and retail) prices and price volatility, and on the integration of wholesale and retail price signals.

Standard electromechanical meter and thermostat technology cannot provide pricing information dynamically; the only type of dynamic pricing that electromechanical technology can support is TOU, which is actually quite static unless the time blocks change in real time. Existing analog, electromechanical watt-hour meters do a poor job of communicating price and usage information to consumers, which is not what they were designed to do. Even in areas where utilites have upgraded or retrofitted their meters to allow AMR, this capability does not exist because AMR requires only one-way communication from the consumer to the utility. Communicating price signals to consumers and/or their devices and then measuring their use while that price is in effect requires two-way communication. Such communication also makes possible finer-grained monitoring that enables the bundled sale of other value-added services (whether energy-related or not). This type of communication technology is known as advanced metering infrastructure (AMI) – a two-way communication metering system that records consumption at intervals and transmits data between the distribution company (and the retailer, if they are different firms) and the customer.

Very few homes are currently equipped with home automation technologies, and data on such uses are not readily available. However, a recent FERC report on demand response and advanced metering (FERC 2006) provided data on AMI penetration by state. Table 1 presents the penetration results of their survey of U.S. utilities. Pennsylvania and Wisconsin have unusually high penetration rates relative to the national average of six percent. Note also the lack of a systematic pattern across restructured or non-restructured states – variables other than state regulatory restructuring contribute to the penetration (or lack thereof) pattern seen in Table 1.

Table 1. Advanced Meter Penetration By State, 2006

State	Advanced Meters	Non-Advanced Meters	Total Meters	Penetration
Pennsylvania	3,176,455	2,879,274	6,055,729	52.5%
Wisconsin	1,199,432	1,782,717	2,982,149	40.2%
Connecticut	592,147	2,174,220	2,766,367	21.4%
Kansas	259,739	1,038,977	1,298,716	20.0%
Idabho	119,024	614,525	733,549	16.2%
Maine	112,104	673,197	785,301	14.3%
Missouri	400,310	2,596,411	2,996,721	13.4%
Arkansas	183,449	1,234,925	1,418,374	12.9%
Oklahoma	138,602	1,788,326	1,926,928	7.2%
Nebraska	64,442	885,019	949,461	6.8%
Kentucky	119,221	2,207,524	2,326,745	5.1%
Texas	572,836	12,514,011	13,086,847	4.4%
Virginia	139,601	3,189,764	3,329,365	4.2%
Colorado	95,582	2,237,762	2,333,344	4.1%
South Dakota	18,192	544,768	562,960	3.2%
South Carolina	65,726	1,987,174	2,052,900	3.2%
Alabama	75,861	2,332,450	2,408,311	3.1%
Georgia	118,239	4,221,386	4,339,625	2.7%
Florida	243,591	9,429,060	9,672,651	2.5%
New Hampshire	19,070	755,259	774,329	2.5%
North Dakota	10,201	413,665	423,866	2.4%
Iowa	21,590	1,072,588	1,094,178	2.0%
Illinois	83,903	5,557,111	5,641,014	1.5%
Washington	41,366	2,967,267	3,008,633	1.4%
Arizona	34,342	2,638,468	2,672,810	1.3%
Indiana	22,103	3,311,080	3,333,183	0.7%
Michigan	29,065	4,665,504	4,694,569	0.6%
Minnesota	15,019	2,482,308	2,497,327	0.6%
New Mexico	4,708	887,354	892,062	0.5%
Alaska	1,358	303,565	304,922	0.4%
New Jersey	15,502	3,851,148	3,866,650	0.4%
California	41,728	14,206,721	14,248,449	0.3%
Oregon	5,284	1,820,389	1,825,673	0.3%
Massachusetts	6,613	3,644,426	3,651,039	0.2%
North Carolina	7,208	4,521,491	4,528,699	0.2%
Montana	739	531,930	532,669	0.1%
District of Columbia	245	231,470	231,715	0.1%
New York	6,933	7,988,548	7,995,481	0.1%
Rhode Island	402	484,196	484,598	0.1%
Ohio	2,199	6,079,222	6,081,421	0.0%
Maryland	641	2,573,546	2,574,187	0.0%
Utah	239	1,051,350	1,051,589	0.0%
Mississippi	101	985,411	985,512	0.0%
Lousiana	112	1,359,878	1,359,990	0.0%
Wyoming	89	1,384,782	1,384,871	0.0%
West Virginia	30	668,972	669,002	0.0%
Tennessee	110	3,044,306	3,044,416	0.0%
Delaware	12	416,518	416,530	0.0%
Hawaii	10	465,304	465,314	0.0%
Nevada	17	1,194,001	1,194,018	0.0%
Vermont	1	329,966	329,967	0.0%

Source: FERC (2006)

Technological changes in digital communications in the past 20 years have increased the ability to achieve this two-way communication, increased the capabilities of the technologies, and decreased their costs (FERC 2006, p. 15). Digital meters can vary in price and functionality from $100 for a simple interval meter and programmable controllable thermostat (PCT), to several thousands of dollars for an automated building control system. This exogenous technological change has the potential to transform the value propositions in the industry.

In the late 1990s, the average hardware cost per meter (including network infrastructure and software costs) was $99 (in nominal dollars); by 2006, the average hardware cost had fallen to $76 per meter. Hardware accounts for approximately 50-70 percent of AMI deployment costs (FERC 2006, p. 34).

The FERC report containing these data (FERC 2006) was prepared in compliance with the Energy Policy Act of 2005's demand response and "smart meter" provisions. Congress passed the Energy Policy Act of 2005 in August, 2005; Title XII of the Act relates to electricity. In particular, Subtitle E, Sections 1252 and 1252, make specific legal changes with respect to demand response and metering technology. Congress directed FERC to investigate and report on the status of demand response and of the installation of advanced metering infrastructure (AMI) that would facilitate demand response. It also directed the Department of Energy to prepare a report quantifying the national benefits of demand response, and directed each state to study demand response, enabling technologies, and the barriers to their implementation in that state.

The Act also requires all utilities (regulated or restructured, IOU or municipal or cooperative) to provide dynamic pricing, stipulating that

> Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology. (EPAct 2005, Title XII, Subtitle E, Section 1252.a.14)

The language of the Act specifies TOU, CPP, RTP, and interruption contracts as forms of time-based rates. It also requires all electric utilities to provide customers requesting a time-based rate with a meter capable of enabling that contract. Congress used striking language for this requirement:

> It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized. (EPAct 2005, Title XII, Subtitle E, Section 1252.f)

As seen with PURPA and EPAct 1992, EPAct 2005's demand response and metering provisions constitute federal-level institutional change, and are inducing state-level adaptation.[7]

Utilities have had only weak cost-based incentive to adopt AMI, as seen in the low penetration rates in Table 1. However, even in the absence of dynamic pricing or regulatory restructuring, AMI can provide substantial operations value to the utility, as the FERC report noted:

> Today, with advances in metering technology and communication systems, advanced meters and infrastructure can provide additional value to utilities by enhancing customer service, reducing theft, improving load forecasting, monitoring power quality, managing outages, and supporting price-responsive demand response programs. For example, if electric load serving entities (LSEs) read meters every day, customer service representatives can assist a customer starting or ending service in one phone call, or more easily handle high bill complaints. With more frequent, hourly reads, customer demand can be totaled across meters served by a feeder line or transformer. This allows electric distribution companies to properly size equipment to handle peak loads, and increase the reliability of service while reducing costs. Hourly reads can also improve the accuracy of load forecasting, allowing LSEs to sell more power into the wholesale market, or reduce spot market purchases. (FERC 2006, p. 18)

[7] EPAct 2005's provisions requiring states to study demand response and its barriers do not apply to states that already had similar proceedings in process; as mentioned earlier, California had instituted such a proceeding in early 2005.

Notwithstanding these valuable capabilities, utilities have been reluctant to make such pervasive changes to their systems without a guarantee from regulators that the investment will be deemed prudent, and that they will be able to recover costs and earn a rate of return on the AMI investment. Thus both the utilities and the regulators must understand the issues surrounding AMI and have enough background to evaluate a benefit-cost analysis of AMI proposals. One of the objectives of EPAct 2005 was creating that awareness and understanding.

Utility meter ownership (a property right that the EPAct 2005 language reinforces) creates some monopsony power in the purchase of AMI for system-wide implementation, and such large-scale implementations enable manufacturers to achieve economies of scale. These factors contribute to lower hardware and implementation costs. This factor was the primary driver of California's recent (2005) regulations requiring their three IOUs to install system-wide AMI.

Some illustrative examples will make these possibilities more concrete.

Example 1: Automated real-time prices to devices. A consumer and a retailer sign a contract under which the retailer will provide service to the consumer and charge the consumer a real-time price (RTP) in 15-minute intervals; that price reflects the fluctuations in the underlying wholesale price, and also includes a charge for the retail customer service function as well as the wires charge that the retailer pays to the wires company. The retailer sends the RTP signal to the digital meter at the home, and the customer has automated the home HVAC system to respond to the price signal. Such programming is Boolean in its logic; for example, the customer could choose a set of trigger prices and an amount to raise the temperature on the air conditioner in response to receiving that trigger price signal.

As part of the service contract, the retailer installs a home gateway portal that includes programmable control of HVAC, lighting, appliances, home entertainment, Internet connectivity, and security. This portal could embed the Boolean logic of automated response to price signals in more user-friendly comfort settings, such as "Economy", "Comfort Weekend", "Comfort Weekday". The customer can also access this gateway remotely and securely, either via computer or via web-enabled mobile telephone, and can generate informative visual and numerical analyses of energy use patterns and expenditures. Such information could even include emissions created and "carbon footprint" of the home, if that information is valuable to the consumer. An example of existing technology that could communicate these prices to devices is the life|ware™ digital entertainment and home automation system from Exceptional Innovation.[8]

Example 2: RTP without prices to devices. A consumer and a retailer sign a contract under which the retailer will provide service to the consumer and charge the consumer a real-time price (RTP) in 15-minute intervals; that price reflects the fluctuations in the underlying wholesale price, and also includes a charge for the retail customer service function as well as the wires charge that the retailer pays to the wires company. The retailer sends the RTP signal to the digital meter at the home, and the customer has chosen not to automate HVAC or appliance devices to respond to prices. Instead, the consumer has chosen a trigger price and has asked to receive an email when the RTP exceeds that trigger. The consumer logs in to a home management web site through the retailer and chooses how to adjust the home's energy settings.

Example 3: Bundling and product differentiation. A customer and a retailer sign a contract that may or may not involve a time-differentiated rate. The retailer analyzes usage pattern data from the digital meter to recommend a bundle of services to the customer. These services need not be energy-related, but could simply use the same communications technology for a variety of valuable services within the home, such as entertainment and security. If the customer does have a dynamic pricing option, the retailer could also recommend different types of pricing depending on the analysis of the usage patterns and the customer's interest in the enabling technology. Site Controls currently offers such services to commercial and industrial consumers, in which they set up a distributed local-area network (LAN) among the various sites that a company owns, and they use the LAN to manage anything from inventory to refrigeration to security.

Example 4: Grid-friendly appliances. A customer and a retailer sign a contract that may or may not involve a time-differentiated rate. In addition to whatever other automation technology the household has, the customer has installed a water heater and a clothes dryer that have

[8] Appendix 1 contains a screen capture of some of the user interfaces in the life|ware™ environment.

GridFriendly™ controller chips. This chip enables the water heater to be programmed to respond automatically to price signals, in the Boolean sense and with the type of user interface described in Example 1. The customer can also override the automated settings, and can log in remotely to adjust the settings. In a clothes dryer, the chip enables the heating element to be turned off automatically for a few seconds or minutes if the chip senses a deviation in power frequency beyond the range of acceptable frequency on the grid. Turning off the heating element can help bring frequency back into its normal range in the event of an excursion, particularly if such technology is widespread. 20 percent of peak demand comes from "white box" appliances, so this automated capability to respond to price signals or frequency deviations can create a substantial resource to reduce system stress in peak hours (Burr 2005, p. 28).

These are just a few of the most obvious uses, although we can anticipate the creation of new products and services but cannot describe the form they will take. These examples illustrate several important points. Digital communications technology opens up a range of potentially profitable bundling and product differentiation that was heretofore impossible, or unattractive because of high transaction costs and interfaces that were not user-friendly. Furthermore, even though retail competition in electric power is rare, the technology exists to embed response to price signals and the choice to automate prices to devices in home energy consumption decisions. In restructured states, large commercial and industrial customers have had these differentiated service bundles available to them, and they have been more likely to choose such services once they no longer paid capped retail prices. However, few of these technologies have been brought to the residential market. Residential customers are perceived as having too low a price elasticity of demand to care about sophisticated energy management, and too small a total household load to matter, either with respect to a retailer's potential profit or to system capacity constraints. The evidence presented in the next section suggests that these presumptions are incorrect.

B. Testing Dynamic Pricing and Enabling Technologies for Residential Customers

Utilities have been experimenting with dynamic pricing for large commercial and industrial customers for over 25 years, and with residential dynamic pricing more recently. Larger customers age generally believed to be more willing and able to respond to price signals than smaller customers. In many, but not all, cases, larger customers have building controls and other installed technology networks that enable them to automate electricity price response behavior more readily and at less cost than smaller customers. Studies over the past 25 years demonstrate that this presumption is generally true, but that large customers do vary greatly with respect to their actual responses to dynamic pricing and to the enabling technology they possess and are willing to use to automate behavioral responses.

Residential customers are generally believed to be less able to change their behavior in response to dynamic pricing, and to be less willing to do so. As with commercial and industrial customers, however, there is considerable heterogeneity within the residential customer class, a heterogeneity that technology and retail entrepreneurs could exploit to provide technologically-interested and early adopter consumers with attractive, novel value propositions. Studies of residential response to dynamic pricing suggest that even without much enabling technology customers do respond to simple price signals; furthermore, when equipped with enabling technology that can include digital home gateways and/or smart, grid-friendly appliances, such technology produces even stronger responses to dynamic pricing.

Studies of consumer behavior in the face of dynamic pricing use two different measures of response: price elasticity of demand (also called own-price elasticity or daily elasticity) and elasticity of substitution. Elasticity of substitution is the measure of response, which looks at the ratio of peak to off-peak quantity relative to the ratio of peak to off-peak price.

1. California Statewide Pricing Pilot, 2003-2004

California's electricity policy challenges, particularly the absence of active demand to discipline the pricing behavior of suppliers, led to the California Statewide Pricing Pilot (SPP). A joint project of the investor-owned utilities, the CPUC, and the California Energy Commission, the SPP tested different pricing structures and how customers responded to them during 18 months between July, 2003 and December, 2004. 2,500 residential and small commercial or industrial customers faced different types of TOU price structures, some of which had a critical peak price

(CPP). All participants faced at least a peak price and an off-peak price, except for one group that received only day-ahead critical period notification, but did not receive price signals. Prices varied seasonally, reflecting the higher cost (and higher value) of providing power during summer months. Participants received digital meters capable of receiving and communicating hourly price signals.

Residential SPP participants faced one of four pricing structures: CPP-F, CPP-V, TOU, and information only. CPP-F involved a fixed TOU structure on all weekdays, but on up to 15 days per year a critical peak price period could be called, for which participants would be notified 24 hours in advance, and the CPP price and length of critical peak were fixed. TOU participants faced the same price structure as the CPP-F households, except that they did not receive any CPP notifications. The CPP-V rate varied from the CPP-F rate in three ways: participants would receive notification of a critical period up to four hours in advance instead of 24 hours, the critical peak period they faced could vary from one to five hours, and they had supplemental enabling technology that they could use to manage their responses to price signals.

The SPP final report includes estimates of both the daily own-price elasticity of demand and the elasticity of substitution. For the CPP-F participants, the daily price elasticity in 2003 equaled -0.035, and the 2004 daily price elasticity was –0.054. The elasticity of substitution in 2003 equaled -0.09, and the 2004 elasticity of substitution was –0.086 (CRA 2005, p. 48). Average reductions in consumption were highest during the summer months (July, August, September), and the houses with central air conditioning had the largest absolute and percent reduction in consumption. Overall consumption did not decrease, so there was no conservation effect among these participants. Unfortunately, the TOU sample size was sufficiently small to limit any inferences that can be drawn from their behavior.

CPP-V participants had daily price elasticities ranging between –0.027 and –0.044, and elasticities of substitution between –0.077 and –0.111. However, the most important result from the CPP-V analysis is that the use of supplemental enabling technology amplified the impact (i.e., reduction of consumption in response to price signal) relative to that seen in the CPP-F sample. The impact of the group with enabling technology was more than double the average

CPP-F impact (27 percent vs. 13 percent) (CRA 2005, p. 109). Furthermore, an econometric decomposition of the impact of the CPP-V decisions indicates that 60 percent of the impact was due to the use of the enabling technology, and 40 percent was due to other behavioral responses. This result is the crucial one for showing the potential that digital technology has for increasing the ease of automating decisions for residential customers, and thus for turning active demand into a network resource.

Information-only participants did not create significant reductions in use during critical hours. This result led the SPP analysts to conclude that demand response is unsustainable in the absence of the price signals inherent in dynamic pricing.

In 2004 the SPP participants had some instances of critical periods being called on multiple days (two or three) in a row. In these cases the repetition did not induce a statistically significant fatigue, or diminution in response to the dynamic pricing.

2. Gulf Power Good Cents Select, 2001-Present

Gulf Power in Florida (a subsidiary of Southern Company) operates a residential demand response program, based on a combination of metering and control technology, customer service, and a TOU pricing structure. Note that this program exists within a vertically-integrated, regulated IOU operating in a state that has not passed any restructuring legislation. Gulf Power's Good Cents Select program uses a four-part TOU price structure, a programmable thermostat that allows customers to establish settings based on temperature and price, meter-reading technology, and load control technology for customers to shift load if they chose in response to price signals. Customers also pay a participation fee, which is one unusual feature of the Gulf Power program.

In 2001, 2,300 residences participated in the Good Cents Select program. In that year Gulf Power achieved energy use reductions of 22 percent during high-price periods and 41 percent during critical (usually weather-related) periods. Furthermore, customer satisfaction is 96 percent, the highest satisfaction rating for any Gulf Power program in its history, notwithstanding the monthly participation fee. Customers say that the $4.53 fee (which covers approximately 60 percent of program costs) is worth the energy management and automation benefits that they derive from participating in the program (Borenstein *et. al.* (2002), Appendix B).

The Good Cents Select program is unique in its use of technology to provide residential customers with automation capabilities. Each home has a programmable gateway/interface that, in addition to allowing thermostat programming, enables the customer to program up to four devices in the home to respond to price signals (GAO 2005, p. 9, p. 42). When surveyed, part of the high customer satisfaction and willingness to pay a monthly participation fee arises from this ability to use technology to manage energy use in the home and increase the ease of making choices in the face of price signals.

3. ComEd/CNT Energy Smart Pricing Plan, 2003-2005

The Energy-Smart Pricing Plan (ESPP) was an innovative three-year residential demand response program, a joint effort between the Center for Neighborhood Technology's Community Energy Cooperative and Commonwealth Edison. In its first year (2003), the program had 750 participants in a variety of neighborhoods and types of homes, from large single-family homes to multiple-unit buildings. In 2004 the program expanded to 1,000 participants, and in 2005 the program had 1,500 participants. It is the only large-scale program in the country that presents residential customers with hourly price signals. Commonwealth Edison provides the hourly prices, on a rate tariff approved by the Illinois Commerce Commission.

The keys to the Energy-Smart Pricing Plan are simplicity and transparency in the transmission of information to residential customers. Participants receive a simple digital interval meter, and can either call a toll-free phone number or visit a website to see what the hourly prices will be on the following day. Furthermore, if the next day's peak prices will exceed 10 cents/kilowatt hour, customers receive a notification by phone, email or fax. Customers will never pay a price above 50 cents/kilowatt hour, which the Community Energy Cooperative implemented by buying a financial hedge at 50 cents.

In 2003, the first year of the program, customers saved an average of 19.6 percent on their energy bills (Summit Blue 2004). They generally joined the program expecting to save \$10/month on average, and were not disappointed. Surveys indicate that the participants found the price information timely, and that with this small inducement to save money on their energy bill by making small behavioral modifications, they actually became more aware of their energy use overall, only in the approximately 30 hours last summer that had higher prices. They also said that their personal contributions toward reduced energy use and improving the environment by participating in this plan really mattered to them.

Although the summer of 2003 was mild in northern Illinois, the econometric analysis of the results showed a price elasticity of demand in those hours, at the margin, of –0.042. On average the residents on ESPP reduced their peak energy use by approximately 20 percent, a number similar to the reductions seen in other residential dynamic pricing programs. In 2004, another mild summer in northern Illinois, the price elasticity of demand was –0.08. As in 2003, the price elasticity of demand for multiple-family dwellings with no air conditioning was surprisingly high: -0.117 (Summit Blue 2005, p. 10).

2005 saw a hot summer in Illinois, with sustained periods of high electricity prices. Over the entire summer, the price elasticity of demand at the margin was –0.047. On the hottest day of the summer, July 15, total electricity consumption by the participants was 15 percent lower than the level of consumption predicted if the participants had not been receiving dynamic price signals.

The hot weather in 2005 also enabled examination of the effects of automated air conditioner cycling. 57 of the participants had automation switches added to their air conditioning in 2004 to enable price-triggered air conditioning cycling during high price notifications. The use of automated switches increased the price elasticity of demand for those customers to –0.069, an increase of 0.022 (46 percent) relative to the elasticity for the total participant pool. This result suggests that automation of control can amplify demand response and the various individual and system benefits that derive from it.

C. Olympic Peninsula GridWise Demonstration Project

The projects discussed in the previous section show that residential customers can and do respond to dynamic pricing, and that enabling technologies increase the ability to respond and magnitude of the effects. The Olympic Peninsula GridWise Demonstration Project looks specifically at the interaction of retail choice and enabling technologies.

The Olympic Peninsula GridWise Testbed Project is a demonstration project, led by the Pacific Northwest National Laboratory (PNNL), testing a residential network with highly distributed intelligence and market-based dynamic pricing. Washington's Olympic Peninsula is an area of great scenic beauty, with population centers concentrated on the northern edge. The peninsula's electricity distribution network is connected to the rest of the network through a single distribution substation. While the peninsula is experiencing economic growth and associated growth in electricity demand, the natural beauty of the area and other environmental concerns mean that the residents wanted to explore options other than building generation capacity on the peninsula or building additional transmission capacity.

Thus this project tested the combination of enabling technologies and market-based dynamic pricing to investigate the effects of dynamic pricing and enabling technology on utilization of existing capacity, deferral of capital investment, and the ability of distributed demand-side and supply-side resources to create system reliability. Two questions were of primary interest in this project: (1) what dynamic pricing contracts are attractive to consumers, and how does enabling technology affect that choice? (2) to what extent will consumers choose to automate energy use decisions?

130 broadband-enabled households with electric heating participated in the project, which lasted for the year April 2006-March 2007. Each household received a PCT with a visual user interface that allowed the consumer to program the thermostat for the home, and specifically to program it to respond to price signals if desired. Households also received water heaters equipped with a GridFriendly™ appliance (GFA) controller chip developed at PNNL that enables the water

heater to receive price signals and be programmed to respond automatically to those price signals. Consumers could control the sensitivity of the water heater through the PCT settings.

These households also participated in a market field experiment involving dynamic pricing. While they continued to purchase energy from their local utility at a fixed, discounted price, they also received a cash account with a pre-determined balance which was replenished quarterly. The energy use decisions they made would determine their overall bill, which was deducted from their cash account, and they were able to keep any difference as profit. The worst a household could do was a zero balance, so they were no worse off than if they had not participated in the experiment. At any time customers could log in to a secure web site to see their current balance and how effective their energy use strategies were.

Upon signing up for the project the households received extensive information and education about the technologies available to them and the kinds of energy use strategies made possible by these technologies. They were then asked to choose a retail pricing contract from three options: a fixed price contract (with an embedded price risk premium), a TOU contract with a variable CPP component that could be called in periods of tight capacity, or a RTP contract that would reflect a wholesale market-clearing price in 5-minute intervals. The RTP was determined using a uniform price double auction, in which buyers (households and commercial) submit bids and sellers submit offers simultaneously. This project is the first instance in which a double auction retail market design has been tested in electric power.

The households ranked the contracts, and were then divided fairly evenly among the three types and a control group that received the enabling technologies and would have their energy use monitored, but did not participate in the dynamic pricing market experiment. All households received either their first or second choice; interestingly, over two-thirds of the households ranked RTP as their first choice. This result counters the received wisdom that residential customers want only reliable service at low, stable prices.

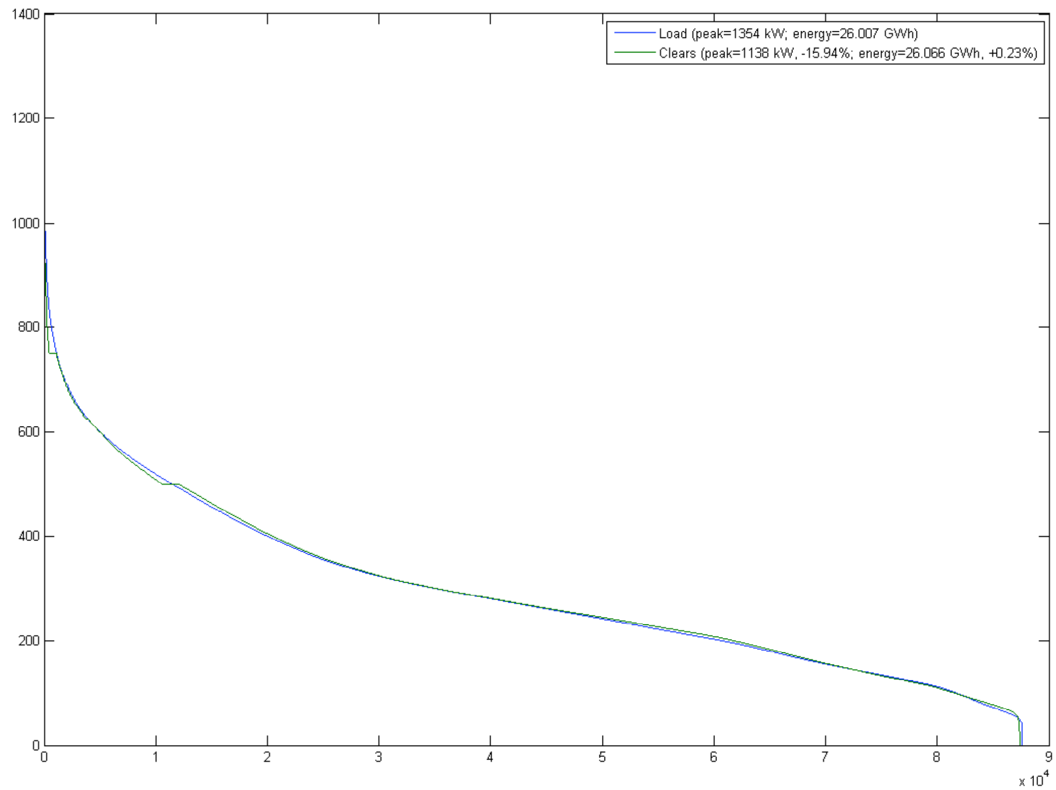
The results of the project have not yet been analyzed fully due to its recent completion, but some preliminary results are striking, based on a preliminary analysis of data from the first nine months of the program.

Preliminary Result 1: For the RTP group, peak consumption decreased by 15-17 percent relative to what the peak would have been in the absence of the dynamic pricing, even though their overall energy consumption increased by approximately 4 percent.

Figure 1 shows the actual and the counterfactual load duration curves between April 2006 and January 2007. Load duration curves plot the number of hours over a given time period that a particular level of consumption is achieved. For example, at X=500 hours, Y=600 kilowatts, meaning that in 500 hours during the almost 10 months in the time series, total consumption in an hour was at least 600kW. In essence a load duration curve shows the distribution of consumption over time; if consumption were distributed uniformly, the load duration curve would be a straight line, and capacity utilization or load factor would be the same at all times. Flattening the load duration curve, which indicates shifting some peak demand to non-peak hours, improves capacity utilization and reduces the need to invest in additional capacity, for a given level of demand. The peak load reduction due to the RTP group is seen at the top left corner, where the green (actual) curve is substantially below the blue (counterfactual) curve. A 15-17 percent reduction is substantial, and is similar in magnitude to the reductions seen in the California SPP program and the Gulf Power program.

Figure 1

Olympic Peninsula Project RTP Actual (Green) vs. RTP Counterfactual (Blue) Load Duration Curve, April 2006-January 2007 (preliminary)



The regression analysis reported in Table A1 in Appendix 2 suggests that, after controlling for price response, weather effects, and weekend days, the RTP group's overall energy consumption was 4 percent higher than the fixed price group's. This result, in combination with the load duration effect noted above, indicates that the overall effect of RTP dynamic pricing is to smooth consumption over time, not to decrease it. Further analysis of the data is required to explore the role of automation and the transmission of price signals to devices in this outcome.

Preliminary Result 2: The TOU group achieved both a large own price elasticity of demand (-0.17) based on hourly data, and an overall energy reduction of approximately 20 percent relative to the fixed price group.

Appendix 2 reports the preliminary results of the econometric analysis of the TOU group hourly data for the first nine months of the program. The regression analysis reported in Table A1 in Appendix 2 suggests that, after controlling for price response, weather effects, and weekend days, the TOU group's overall energy consumption was 20 percent lower than the fixed price group's. This result indicates that the TOU (with occasional critical peaks) pricing induced overall conservation, a result that is consistent with the results of the California SPP project.

Table A2 reports a time series estimation of the price elasticity of demand in the TOU group; the coefficient estimate is -0.17. The price elasticity estimate is calculated using an ARIMA model with a 1, 4, 8, and 24-hour lag structure to control for natural autoregressive characteristics of energy use over the course of a day, as well as weather-related variables and weekend days. While consistent with the large conservation effect mentioned above, this price elasticity of demand estimate is high relative to those observed in other projects, and will require further analysis. One hypothesis to test is whether the automation capabilities of the technologies contributed to an increased price elasticity. The California SPP found a marginal conservation effect from the technology, but not a marginal price elasticity effect; however, their technology did not include as much ability to automate responses to price signals as the GridFriendly™ technologies employed in this project.

Preliminary Result 3: The fine-grained automation and price response capabilities in 5-minute intervals change the nature of the RTP problem and its analysis.[9]

Although the load duration curves presented in Figure 1 indicate that the RTP group did respond to prices and did reduce their use in peak hours, traditional statistical techniques have generally not indicated a statistically significant price elasticity of demand. Furthermore, the price elasticity results for the RTP group are highly specification-dependent – the sign, magnitude, and statistical significance of the elasticity estimate vary greatly depending on model specification.

One of the useful features of the market design, though, is that as a double auction we have data on the actual bids submitted by the devices in the households (and the 2 commercial consumers).

[9] I am indebted to my co-author at PNNL, David Chassin, for the preliminary quantitative analysis reported here.

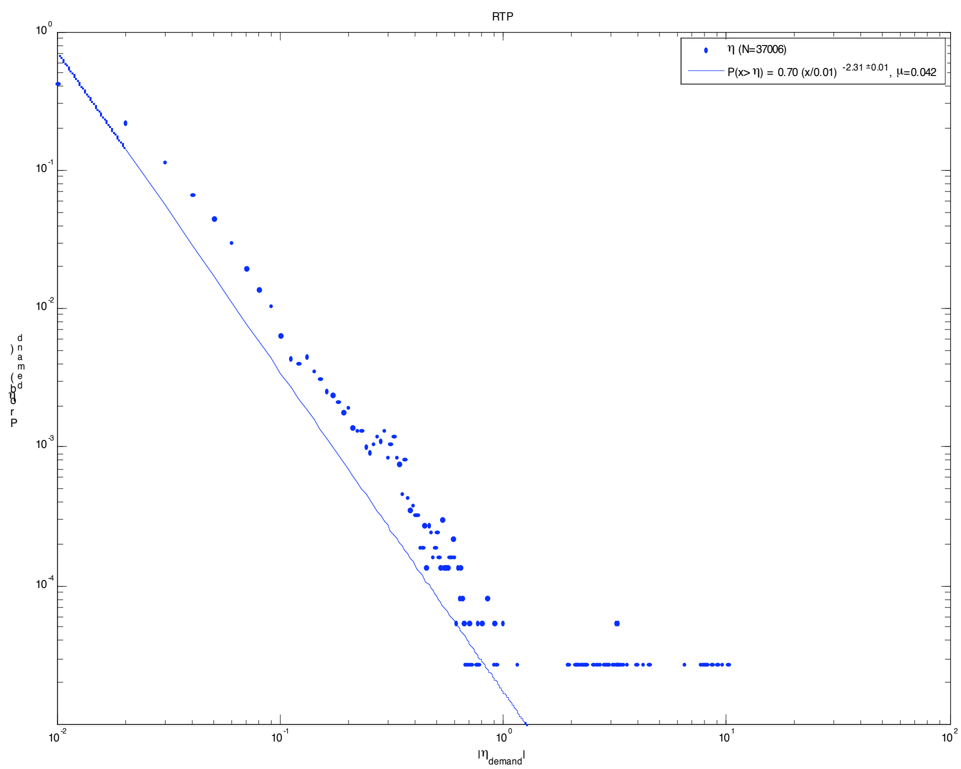
Using those actual bids, we calculated price elasticity relative to the market-clearing price, using the bids as the structural demand function. Thus, the demand elasticity is

$$\eta = \frac{Q_{clear}}{P_{clear}} \frac{P_{clear} - P_{bid}}{Q_{bid}}$$

Analyzing those structural price elasticities in 5-minute increments reveals that they are not normally distributed. Rather, the price elasticity data follow a Pareto distribution, which is a power law distribution. Figure 2 shows a plot of the structural price elasticity data on the x-axis and the probability of that elasticity occurring in the data on the y-axis. The asymptotically linear nature of the relationship seen in Figure 2 is consistent with data drawn from a power law distribution.

Exhibiting a power law distribution has two important implications for this analysis. First, when data exhibit a power law relationship they are scale-free or scale-invariant, which suggests that as more households have automation capabilities in response to price signals, the results we have observed in this project would not change meaningfully at different scales or market sizes. Another way to think of the scale-free characteristic is if the same project were run on populations of different sizes, even dramatically different sizes, the pattern seen in the elasticity data would not change. Second, in complex systems a power law relationship indicates robustness and self-organization, and is thus consistent with the RTP double auction being an equilibrating process.

Figure 2: Structural price elasticity results for the complete RTP data set



These preliminary results suggest that the technological and institutional capacity to send prices to devices changes the nature of the network, its information content, and the choice set for individual behavior quite significantly.

D. Summary of Results

Table 2 summarizes the own-price elasticity, elasticity of substitution, and impact/peak consumption reduction results in the projects discussed above. The range of results and the consistency of some degree of impact across the studies indicate that consumers can and do respond to dynamic pricing, and that installed enabling technologies creates the opportunity for them to amplify that response by automating their behavior.

Table 2
Summary of Elasticity and Impact Results

Location and Contract Type	Type of Customer	Study	Year	Own-Price Elasticity	Elasticity of Substitution	Reduction of Peak Consumption
CA CPP-F	Residential	CRA (2005)	2003	-0.035	-0.09	
CA CPP-F	Residential	CRA (2005)	2004	-0.054	-0.086	13% (average)
CA CPP-V	Residential w/technol.	CRA (2005)	2003-2004	-0.027 to -0.044	-0.077 to –0.111	27% (average)
Gulf Power	Residential	Borenstein et. al. (2002)	2001			22% (high price sig) 41% (weather crit.)
Chicago ESPP	Residential	Summit Blue	2003	-0.042		
Chicago ESPP	Residential	Summit Blue	2004	-0.08		
Chicago ESPP	Residential	Summit Blue	2005	-0.047		
Chicago ESPP	Residential w/AC switch	Summit Blue	2005	-0.069		
Olympic Peninsula RTP	Residential	Preliminary results	2006			15-17% (average)
Olympic Peninsula TOU	Residential	Preliminary results	2006	-0.17		

These field experiments indicate that dynamic pricing does induce customers of different types and sizes to manage their own energy use in response to price signals. Even within traditional customer classes, consumers are heterogeneous, and dynamic pricing enables that heterogeneity of demand response to contribute to system reliability and to economizing on necessary infrastructure capital investment. Furthermore, enabling digital technology like building management systems, home gateways, and grid-friendly appliances amplify demand response, and work in conjunction with dynamic pricing to empower and inform consumers while contributing to system reliability and economic efficiency in the network as a whole.

V. Conclusion

The evidence presented in this analysis demonstrates that residential electricity customers can and do choose to respond to dynamic pricing. Digital communication technologies contribute to that response. Such response benefits the individuals as well as creating system reliability benefits through deferred capital investment and reduced requirements for costly standby generation contracts in peak hours.

Dynamic pricing and the digital technology that enables communication of price information are symbiotic. Dynamic pricing without enabling technologies is meaningless; technology without economic signals to which to respond is extremely limited in its ability to coordinate buyers and sellers in a way that optimizes network quality and resource use. The combination of dynamic pricing and enabling technologies changes the value proposition to the consumer from "I flip the switch and the light comes on" to a more diverse and consumer-focused set of value-added services.

Notwithstanding these results, dynamic pricing and enabling technologies are proliferating slowly in the electricity industry. Proliferation requires a combination of formal and informal institutional change to overcome a variety of barriers; formal institutional change in the primary form of federal legislation is reducing some of these barriers, but it is an incremental process. The traditional rate structure, fixed by state regulation and slow to change, presents a substantial barrier. Predetermined load profiles inhibit market-based pricing by ignoring individual customer variation and the information that customers can communicate through choices in response to price signals. Furthermore, the persistence of standard offer service at a discounted rate (i.e., a rate that does not reflect the financial cost of insurance against price risk) stifles any incentive customers might have to pursue other pricing options.

The most important, yet also the most intangible and difficult to change, obstacle to dynamic pricing and enabling technologies is the set of incentives for inertia. The primary stakeholders in the industry – utilities, regulators, and customers – all have status quo bias. Incumbent utilities face incentives to maintain the regulated status quo to the extent possible, given the economic, technological and demographic changes surrounding them; they have been successful at using the political process to achieve this objective. Customer inertia is deep because they have not had to think about their consumption of electricity and the price they pay for it; consumer advocates typically reinforce this bias by arguing for low, stable prices for highly reliable power as an entitlement. Regulators and customers explicitly value the stability and predictability that the vertically-integrated, historically supply-oriented and reliability-focused environment has created. But what is unseen and unaccounted for is the opportunity cost of such predictability – the foregone value creation in innovative services, empowerment of customers to manage their own energy use, and use of double-sided markets to enhance market efficiency and network reliability. Compare this unseen potential with the value creation in telecommunications, where even young adults can understand and adapt to cell phone pricing plans, and benefit from the stream of innovations in the industry.

The potential for a highly distributed, decentralized network of devices automated to respond to price signals creates new policy and research questions. Do individuals automate sending prices to devices? If so, do they adjust settings, and if so, how? Does the combination of price effects and innovation increase total surplus, including consumer surplus? In aggregate, do these distributed actions create emergent order in the form of system reliability?

Answering these questions requires thinking about the diffuse and private nature of the knowledge embedded in the network, and the extent to which such a network becomes a complex adaptive system. The framework for thinking about the economics consequences of such a technology-enabled, knowledge-rich distributed system incorporates elements of complexity science, Austrian economics, and new institutional economics (NIE). The synthesis of these approaches models the problem of prices to devices as one in which knowledge is distributed and necessarily incomplete (Hayek 1945, Kirzner 1997), the interaction of the decentralized agents acting with distributed control (e.g., self control in response to individual incentives) can lead to emergent self-organization (Holland 1995, pp. 6-10), and the institutions (both formal and informal) governing the system matter greatly for shaping individual decisions and overall outcomes. The evidence presented here, particularly the preliminary evidence from the Olympic Peninsula GridWise Project, points to that synthesis as a possible area of future research, both in understanding individual behavior in a world where prices to devices are possible and in thinking about the types of regulatory institutions that complement such a vision of the electricity industry.

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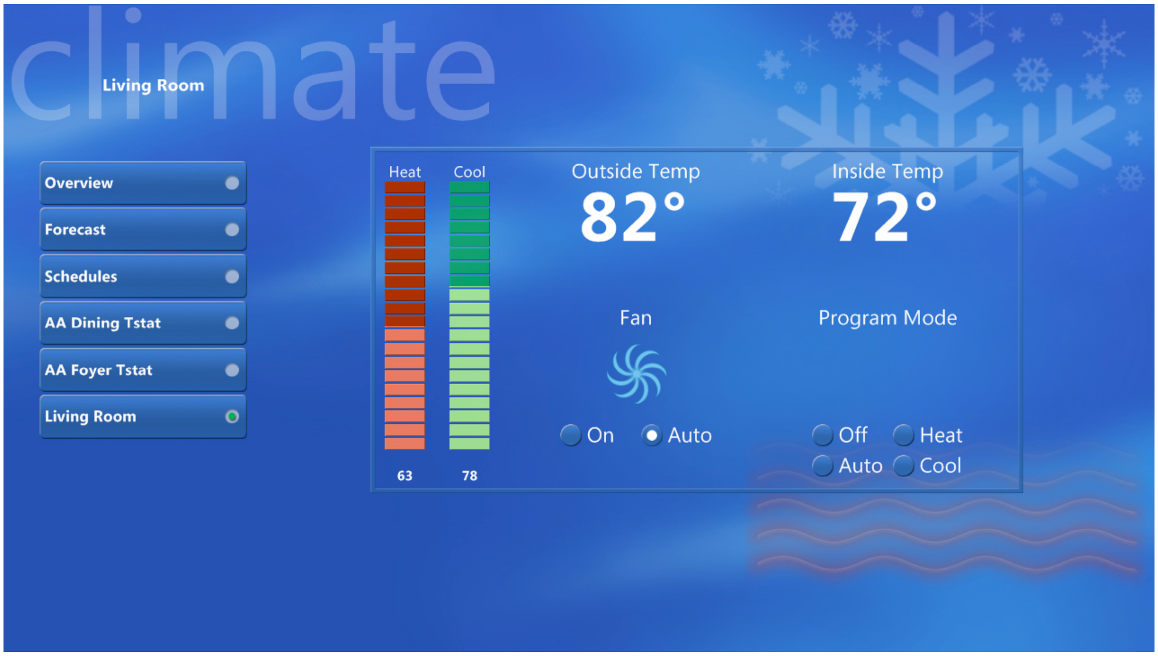
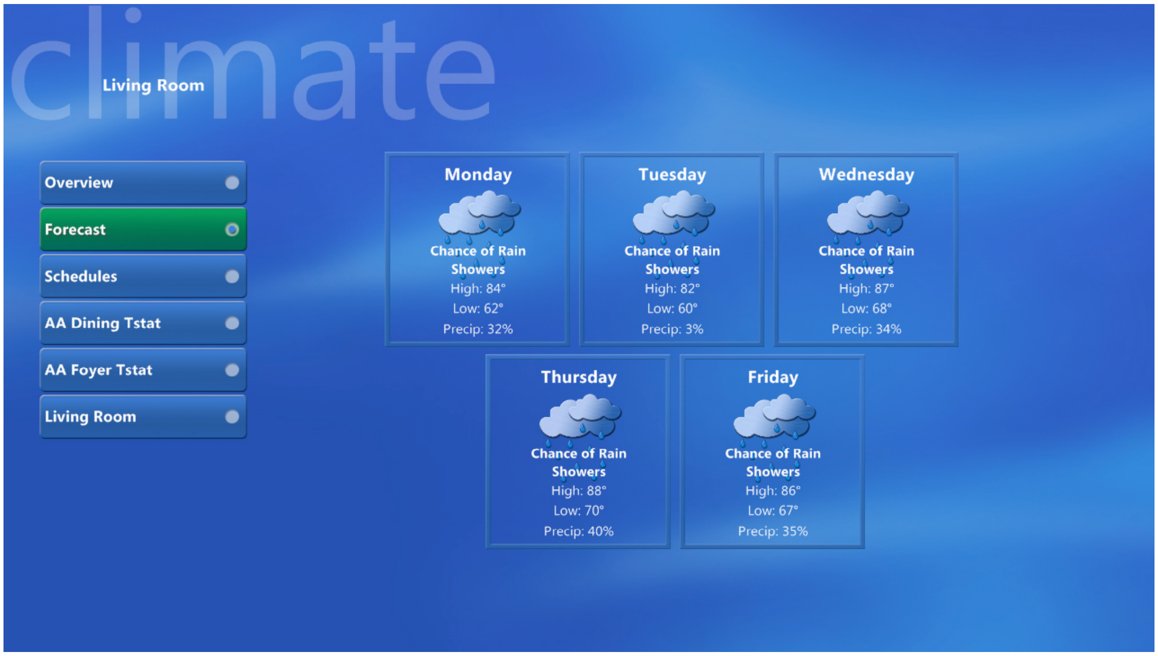
Appendix 1
Life|ware screen captures





Source: http://www.exceptionalinnovation.com/products.php

Appendix 2
Preliminary Econometric Analysis of Olympic Peninsula GridWise Demonstration Project

Table A1
OLS regression to isolate marginal effect of being on the TOU and RTP contracts

```
. regress lnenergy lnprice saturday sunday weather wind humidity tou rtp, robust

Linear regression                                      Number of obs =   19687
                                                       F(  8, 19678) = 1093.94
                                                       Prob > F      =  0.0000
                                                       R-squared     =  0.3263
                                                       Root MSE      =  .41488

------------------------------------------------------------------------------
             |               Robust
    lnenergy |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
     lnprice |   .1448562   .0083975    17.25   0.000     .1283962    .1613161
    saturday |   .0187938   .0086643     2.17   0.030     .0018109    .0357766
      sunday |   .0756435    .009022     8.38   0.000     .0579597    .0933273
     weather |   .0335761   .0004066    82.59   0.000     .0327792     .034373
        wind |  -.0071104   .0008578    -8.29   0.000    -.0087917   -.0054291
    humidity |   -.006837   .0002049   -33.37   0.000    -.0072386   -.0064354
         tou |  -.2006103   .0077279   -25.96   0.000    -.2157575    -.185463
         rtp |   .0426333    .009512     4.48   0.000      .023989    .0612776
       _cons |   3.351747   .0415579    80.65   0.000      3.27029    3.433204
------------------------------------------------------------------------------
```

Table A2
AR regression, TOU group only, lag structure AR(1 4 8 24)

```
. arima lnenergy2 lnprice2 saturday sunday weather wind humidity, ar(1 4 8 24) robust

Number of gaps in sample:  1
(note: filtering over missing observations)

(setting optimization to BHHH)
Iteration 0:   log pseudolikelihood =  1149.2582
Iteration 1:   log pseudolikelihood =  1773.7526
Iteration 2:   log pseudolikelihood =  1960.1353
Iteration 3:   log pseudolikelihood =  1978.8368
Iteration 4:   log pseudolikelihood =  1980.4968
(switching optimization to BFGS)
Iteration 5:   log pseudolikelihood =  1980.6704
Iteration 6:   log pseudolikelihood =  1980.6947
Iteration 7:   log pseudolikelihood =  1980.6951
Iteration 8:   log pseudolikelihood =  1980.6951
Iteration 9:   log pseudolikelihood =  1980.6951

ARIMA regression

Sample:  317744 to 324343, but with gaps
                                                Number of obs      =       6598
                                                Wald chi2(10)      =   50788.81
Log pseudolikelihood =  1980.695                Prob > chi2        =     0.0000

------------------------------------------------------------------------------
             |            Semi-robust
   lnenergy2 |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
lnenergy2    |
    lnprice2 |  -.1709742   .0103838   -16.47   0.000     -.191326   -.1506224
    saturday |  -.0004039   .0093687    -0.04   0.966    -.0187662    .0179584
      sunday |   .0102507   .0096391     1.06   0.288    -.0086416    .0291431
     weather |   .0167943   .0011578    14.50   0.000      .014525    .0190637
        wind |  -.0004381    .000781    -0.56   0.575    -.0019689    .0010926
    humidity |   -.000704   .0003194    -2.20   0.027      -.00133   -.0000781
       _cons |    4.11171   .0617684    66.57   0.000     3.990646    4.232774
-------------+----------------------------------------------------------------
ARMA         |
          ar |
         L1. |    .537301   .0110945    48.43   0.000     .5155563    .5590458
         L4. |  -.1252089   .0064008   -19.56   0.000    -.1377542   -.1126636
         L8. |   .0579915   .0055723    10.41   0.000     .0470699    .0689131
        L24. |   .4826831   .0100405    48.07   0.000     .4630041    .5023621
-------------+----------------------------------------------------------------
      /sigma |    .179013   .0017466   102.49   0.000     .1755897    .1824363
------------------------------------------------------------------------------
```