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Riding the Electricity Market as an Energy Management Strategy: Savings from Real-Time Pricing

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ABSTRACT

Dynamic pricing of electricity, in which retail prices facing customers are responsive to changes in the underlying wholesale markets, represents a step towards economic efficiency in that customers get exposed to some or all of the costs facing wholesale market players. But what do customers who opt for this greater exposure – available in the roughly 15 "de-regulated" states, as well as, to some extent, from some regulated utilities – get in return for their risks? The U.S. General Services Administration (GSA) took a retrospective eight-year look at what the savings would have been had they let the loads for which they purchase electricity in the Washington, DC area buy electricity on the real-time pricing (RTP) market – the dynamic pricing option with the highest risk – as opposed to the strategy they chose in actuality, which was fixing flat prices with 3rd-party providers. We found that opting for RTP for the eight years of the study (2005 through 2012) would have resulted in 17% savings, or almost a quarter of a billion dollars, relative to GSA's actual prices from the 3rd-party suppliers. This is particularly astonishing given that GSA appeared to have timed the market well during the study period, consistently beating the standard offer products provided by the distribution utilities. The issue of budgetary predictability poses an obstacle for customers (especially government ones) considering RTP and, to a lesser extent, other dynamic pricing options. Indeed, GSA would have lost money with RTP in two of the eight years, one of them substantially. But the magnitude of the savings is indisputably compelling and, even if it may be somewhat aberrational due to high congestion in the DC market, begs consideration by large electricity users currently paying to "lock in" fixed flat prices.

Introduction

Dynamic pricing for electricity refers to retail pricing that is responsive to changes in the underlying wholesale markets. Examples include real-time (sometimes called "hourly"), day-ahead, and "block-and-swing" (also called "block-and-index") pricing – in which a portion (or block) of an end-use customer's power needs are secured at a fixed rate but any usage beyond that is exposed to real-time prices. Another popular variant, called "critical peak pricing" or "peak day pricing," involves the identification for participating customers, usually with one day's notice, of a number of peak, or "critical peak," days; on these utility-called peak days, prices spike to several times their usual rate (for instance, if the usual price is $0.10/kWh, during a critical peak the charge might be $0.40-0.80/kWh). In exchange for accepting the occasionally elevated charges, customers are charged a significantly lower rate for their usage outside of these select periods (usually hot summer afternoons but also sometimes very cold winter mornings when demand for electric heating is high and the grid may be in jeopardy due to interruptible gas plants, frozen coal supplies, etc.).

Where electricity is traded in competitive wholesale markets, its price is extremely volatile relative to most commodities. The reason for this is that electricity cannot be stored cost-effectively and thus must be generated when demanded. And demand is very uneven, usually increasing during the day and falling at night, with large rises most commonly occurring during high temperatures when use of air conditioning (sometimes referred to by utilities as "the load from hell") spikes. In addition, the *cost* of supplying power varies with both fuel and generation technologies, such that only when demand is highest are the most expensive plants turned on. It is these features that have spawned the creation of dynamic rates, which can be thought of as a mechanism to share price risk between suppliers and consumers.

Accepting the neoclassical economic theory that commodities are most efficiently rationed by price, it is reasonable to assume that electricity would follow this premise. However, electricity has traditionally been sold to end-use customers at flat fixed prices. There are two main reasons for this: First, the meters commonly used to measure electricity have traditionally been cumulative meters, which are read monthly, and not time-differentiated ones. This is clearly changing in the U.S. – witness that even in the U.S. residential sector, where the case for their use is less compelling, over 40 million "interval meters" (generally ones that can read usage at hourly or finer frequency) were installed through mid-2014 (EIA 2015). Historically, however, utilities did not see interval metering as a sensible investment, at least for customers outside of their very largest. Second, wholesale electricity markets are relatively new phenomena in the U.S., dating primarily to the 1990s; before this, and continuing in many parts of the country today, electric distribution utilities were granted monopolies for not only their distribution networks, but also for power generation. The state commissions that regulated them directed that they offer their power at fixed rates. In exchange, utilities were allowed to build power plants, including peaking plants to accommodate the demand from customers, and earn a reasonable rate of return doing so. While there have certainly been some exceptions in which these conventionally regulated utilities have offered time-varying rates, they were – and are still – rare.

These power generation monopolies have been broken up, largely due to the evolving realization that electricity generation, unlike distribution, is not a natural monopoly. However, large end-use customers, given permission to shop for their ultimate power supply in de-regulated electric markets (present in roughly 15 U.S. states), have in most cases continued to seek flat-priced electricity even amidst an array of dynamic pricing options. This is presumably in part because of the budgetary predictability of a flat price and the fact that this is what they are used to. In addition, Barbose et al. (2004) surveyed utilities with real-time price options who claimed that limited savings (without significant price responsiveness of loads) and high price risk were also deterrents for customers. However, what may be lost on many of these customers is that their fixed rates come at a cost. Especially because the volatility in wholesale markets is often so high, the premium for suppliers to provide fixed rates is also high. While there seems to be barely anything in the literature that reinforces it, many market watchers estimate this to be 5-10% over the long run, when comparing fixed "full requirements" prices with real-time or day-ahead ones. A look at the price path from any wholesale electricity market makes the magnitude of this premium plausible – suppliers are faced with volatility that is substantial not only within individual days, but also across weather patterns (and, relatedly, seasons).

In addition to the savings from avoiding the fixed price premium, end-use customers who accept dynamic retail pricing also have the ability to amplify their savings by using load management techniques to avoid the somewhat predictable price peaks (there is a generally dependable diurnal pattern of prices in which they are low overnight and rise during the day, and this is particularly pronounced in hot weather). "The customers in [dynamic pricing tariffs] avoid paying the hedge premium associated with flat-rate service. They realize additional savings when they adjust usage to avoid high prices" (Neenan Assocs., 2005). For instance, a large site might choose to run its generator at a time when market prices have spiked, or to delay an industrial process or energy-intensive lab experiment. For instance, Taylor et al. (2005) found that, as industrial customers spent more time on a Duke Power opt-in real-time rate, they got more savvy at shifting usage away from high-priced periods, on average saving about 4% (or $14,000 per month) compared to the time-of-use rate alternative. Barbose et al. (2006) found substantial price elasticities among large customers when prices were very high and day-ahead notice was provided.

Nonetheless, while numerous studies (e.g., Borenstein, 2005; Neenan Assocs, 2005; Goldman, 2006) address its expected presence, and market players have estimated expected long-run savings, there is a dearth of studies that have investigated the specific magnitude of the savings from dynamic pricing in the absence of participant responsiveness. In other words, just how much is the "risk premium" that can be avoided by moving off of fixed pricing and accepting market exposure? As summed up by a 2011 report by the National Association of Regulatory Utility Commissioners (NARUC) for the Washington State utility commission, the economic benefits of dynamic pricing are well touted, but almost only in theoretical explanations. The "benefits are often represented in abstract terms, founded upon the broad, simplistic economic theory that exposing retail electric customers to market prices for power supply will automatically produce large … benefits."

Government sites are classic examples of facilities that can benefit from avoiding the flat-rate price premium. While the vagaries of the market are such that, in any given year, a facility on dynamic pricing might experience considerably varying results, the long-term outcome will converge toward the average. Government facilities, because they are generally long-term in their physical presence and ownership, can afford to take a long-term perspective in their electricity procurement. *National* government facilities stand to benefit not only from this ability to take advantage of their temporal longevity (and thus one form of diversification), but also from the fact that they are geographically diversified, such that tight, expensive markets in one part of the country may be counterbalanced by cheaper ones elsewhere, particularly with differing weather trends in the different locales.

This paper reports on a study conducted by the U.S. General Services Administration (GSA), essentially the landlord for most of the civilian side of the government, to investigate the prospective benefits of choosing dynamic electric pricing for its facilities (and those of other federal agencies for whom it regularly acts as buyer). While the study focuses on the Washington, D.C. area, where the government has considerable presence, the goal was to gain insight into the merits of dynamic pricing across the federal buildings portfolio.

Some of the buildings that GSA buys electricity for are located in traditional, regulated markets, in which utilities have a granted monopoly over power supply. Others, about half of GSA's overall load, reside in deregulated markets, in which large buyers can competitively source their electricity from third-party suppliers. GSA purchases roughly 4.6 million MWh per year in electricity across 14 of these de-regulated states and the District of Columbia.

Since the early 2000s, GSA's policy in deregulated markets has been to solicit bids through a competitive auction process for "fixed full requirements" contracts, which obligate the winning bidder to provide the government's electricity requirement at a predefined cost per kilowatt-hour (kWh). This removes the government's price volatility risk (within the term of a contract) and ensures budgetary certainty in the years ahead. Contracts are typically two to four years long and are renewed when conditions are perceived to be conducive to beating the market for the term of the contract. They generally contain a "bandwidth" clause that allows suppliers contractual relief if usage varies by more than 10% of the amount estimated.

In these deregulated markets, GSA also has the option of putting its buildings on the real-time (often referred to as "hourly") electricity market or other dynamic pricing options. While this "index" pricing is conventionally thought to achieve lower total costs than fixed-price contracts, as discussed above, the risk premium savings have been uncertain and the price risk deemed too high by GSA. As such, only facilities with special load management equipment (e.g., cogeneration plants or thermal energy storage systems) have been put on index pricing, with the vast majority of accounts (and load) on fixed-price contracts.

In the fall of 2012 GSA decided to look backwards and compare how much it paid through its fixed-price contracts in one of its key markets, the Washington, DC area, against what it *would have paid* if all those accounts had been on a pure hourly index price.

Method

The question the study sought to answer is: Do real-time prices make sense in the long run given GSA's consumption patterns? As a first step, hourly consumption data for all of 2011 was obtained from PEPCO, the facilities' distribution utility, for the 154 large accounts for which GSA buys electricity on fixed-price contracts in the DC area. These 154 accounts had a combined annual electrical consumption of approximately 2.25 billion kilowatt-hours (kWh) and a combined peak load of approximately 400 megawatts (MW). The hourly consumption data added up to well over a million data points. Every building's usage was then added together to get a total for the portfolio for each hour of the year, making the data more manageable. This year's worth of load data was then extrapolated backwards (essentially copy-pasted), taking care to match weekends with weekends, to obtain GSA's best estimate of what the historical load would have been going back to January 1st, 2005 (the earliest date for which GSA has locational marginal price data). This was done because the load data for the years prior to 2011 was not available from PEPCO. GSA feels confident that yearly energy usage patterns remained essentially the same over the 8-year study period, at least on a portfolio-wide (all 154 buildings) basis, making it possible to apply one particular year's worth of load data to the other years of the study.

Each hourly usage amount was then multiplied by the corresponding locational marginal price (LMP) at the "PEPCO" zone of PJM Interconnection, the transmission grid operator, to obtain the hourly cost of the 154 buildings for each hour from January 1st, 2005 to December 31st, 2012. Each of these hourly amounts was added together to get the total portfolio cost by year, and for the entire study period. A supplier margin fee and estimated ancillary costs totaling $4/MWh were added to the real-time cost to make for an equal comparison to the fixed rate. The ancillary fee and supplier margin cost estimates were based on a review of PEPCO invoices in 2009 and 2010.

The next step in the study was to estimate the actual cost of the 154 buildings in the study according to the fixed price contract they were on. This was done by taking the same totalized interval consumption data for the entire portfolio, and multiplying each hourly usage by the fixed contract rate that was in effect at that time. Again, each of these amounts was added together to get the total portfolio cost by year, and for the entire study period. Capacity, transmission, and other system demand charges were not added to either the fixed or real-time costs, since these items are identical (and passed through to government end users by GSA for both contract types).

The buildings in this study were operated almost entirely without regard to real-time price spikes. Building operators did receive "peak load contribution" predictor emails (provided by a consulting service to help GSA's customers avoid pass-through PJM demand charges that are assessed based on end-users' loads during PJM's five highest system loads of the year) that encouraged them to reduce their load for three to four hours on ten to twelve days per summer, but on a portfolio-wide basis the effect of these emails is not discernible with a visual inspection of the graphed data, so assumed to be minimal. In an actual hourly price situation, building operators would be more likely to take steps to shift building load to mitigate high prices, particularly on high demand days during the summer (assuming they had sufficient information on market trends, such as with day-ahead pricing).

Results

To reiterate, the study was seeking to assess whether real-time prices make sense in the long run given GSA's consumption patterns. The answer to this question is definitely yes: GSA would have saved, on average, over 1¢ per kWh if its PEPCO DC buildings had been on hourly, instead of fixed, pricing over the eight-year study period. The average fixed price was $.076/kWh, while the average index cost would have been $.063/kWh, or 17% less. This represents missed savings of roughly $230 million over the eight-year period.

The PEPCO zone has somewhat unusual market dynamics that may lend themselves to particularly stark results. There is a good deal of transmission congestion, yielding higher than average market fluctuations and uncertainty relative to other PJM zones, most likely adding to the risk premium in suppliers' fixed-price quotes. This higher premium would serve to widen the average spread between real-time and fixed prices, suggesting that such drastic savings will not necessarily be available in other markets.

While the index cost came out well below the fixed-price costs over the study period, the yearly variation between the portfolio's electricity costs was, not surprisingly, considerably larger than the variation experienced on fixed-price contracts over the same period, as summarized below. The average year-over-year variation came to 22%, while the fixed-price contracts' costs varied by only 9%.

Table 1: Change in average price from one study year to the next under GSA's actual fixed-price contracts and, hypothetically, with real-time pricing (RTP).

Years	Change in Fixed Price	Change in avg. RTP
2005-2006	+46%	-14%
2006-2007	-1%	+17%
2007-2008	0%	+15%
2008-2009	0%	-47%
2009-2010	-12%	+26%
2010-2011	0%	-10%
2011-2012	0%	-24%

Moreover, the surprisingly high risk premium savings from the real-time pricing versus the fixed across the entire 2005-2012 study period was spread very unevenly across the eight years. In fact, in two of the years (2005 and 2008), GSA's customers would have *lost* money by choosing the index pricing. In 2005, this loss would have represented nearly 2¢ per kWh, (7.6¢ vs. 5.7¢), or 33%, amounting to more than $44 million.

Table 2: Annual total expenditures under GSA's actual fixed-price contracts and, hypothetically, with real-time pricing.

Year	Fixed Price Total	RTP Total	Savings from RTP
2005	$128,255,837	$172,371,367	($44,115,529)
2006	$187,771,819	$147,379,453	$40,392,366
2007	$186,643,407	$172,453,501	$14,189,906
2008	$187,169,300	$197,841,136	($10,671,837)
2009	$186,631,501	$104,167,340	$82,464,161
2010	$164,526,740	$131,748,914	$32,777,825
2011	$164,387,894	$118,637,996	$45,749,897
2012	$164,847,205	$92,294,049	$72,553,156
Total	**$1,370,233,702**	**$1,136,893,758**	**$233,339,944**

Table 3: Annual average unit costs under GSA's actual fixed-price contracts and, hypothetically, with real-time pricing, along with the percent difference.

Year	Contract Price Unit Cost	Real-Time Unit Cost	% Difference
2005	$ 0.057	$ 0.076	33.3%
2006	$ 0.083	$ 0.065	-21.7%
2007	$ 0.083	$ 0.076	-8.4%
2008	$ 0.083	$ 0.087	4.8%
2009	$ 0.083	$ 0.046	-44.6%
2010	$ 0.073	$ 0.058	-20.5%
2011	$ 0.073	$ 0.053	-27.4%
2012	$ 0.073	$ 0.041	-32.8%
Total	**$ 0.076**	**$ 0.063**	-17.1%

It bears mentioning that market timing on behalf of GSA's procurement staff affected the results of this study. As the PEPCO DC fixed-price contract came near expiration, GSA staff would follow market trends and consult industry experts in order to time the follow-on solicitation. Hindsight reveals that GSA was more likely to lock in below-market prices based on its market timing decisions (see Figure 1). Indeed, GSA was successful in this timing in as much as it consistently saved money with its actual electricity procurement in DC (between 8% and 20% over the years of the study) relative to the default PEPCO tariff. In other words, without GSA's fortuitous market timing, the real-time savings would have been even greater.

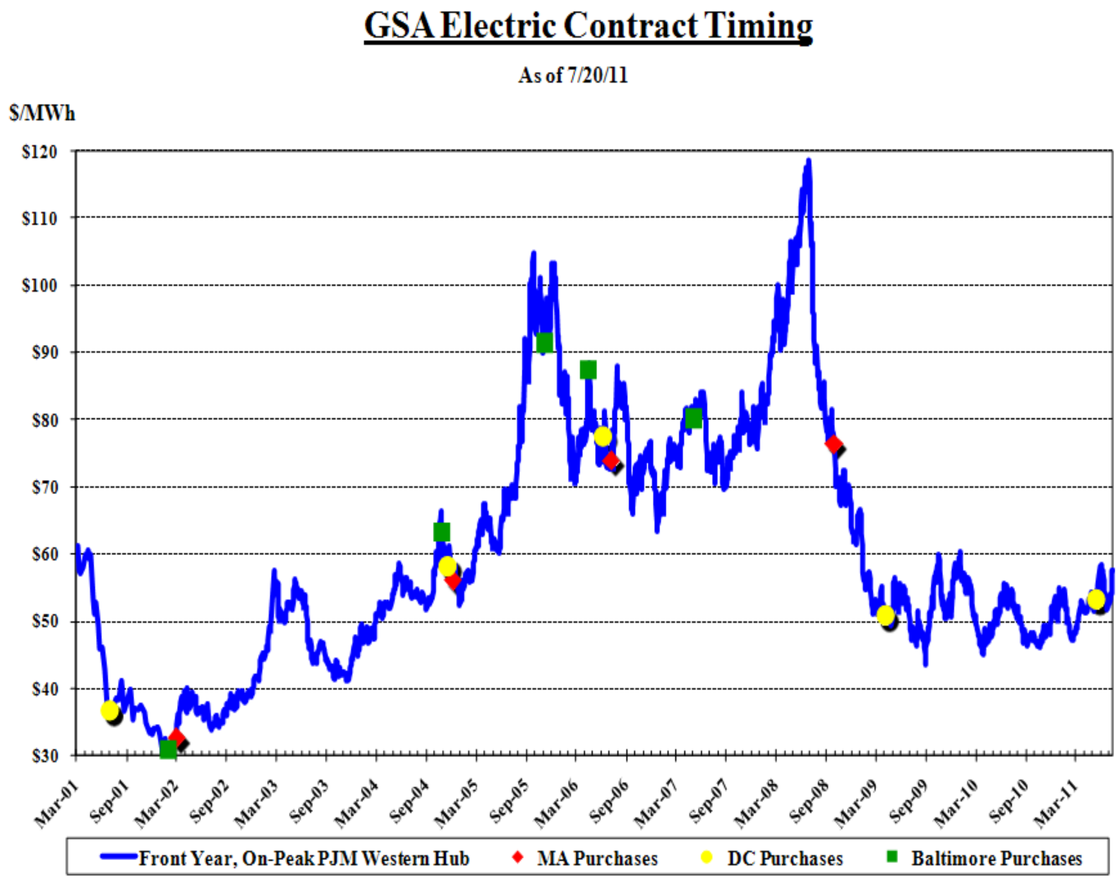

Figure 1: Colored dots indicate when GSA "pulled the trigger" on signing multi-year fixed price electricity contracts in various east coast markets. Two markets other than DC are used to show relative performance of the DC purchases.

However, there is no question that real-time prices were, on average, lower than the fixed-price contract prices, even without close analytical scrutiny (see Figure 2).

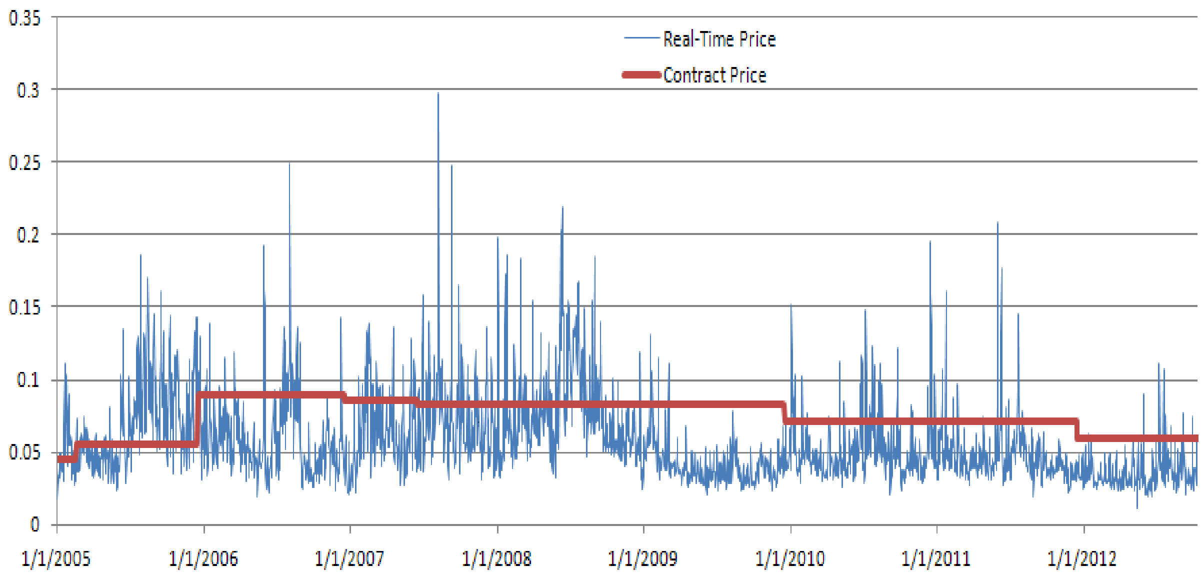

Figure 2: Area below the red line but above the blue represents savings to real-time pricing (RTP); the spikes above the red line represent instances where sites would have lost in RTP relative to the fixed price.

Conclusion/Discussion

The potential cost difference demonstrated by moving from fixed to real-time pricing in this study was a surprising finding for GSA, not so much in its direction – which was expected by the authors – but rather its magnitude (17%). Further study is needed to assess the savings potential in other markets, such as less congested zones in PJM as well as those in other ISO/RTO markets like ISO-New England, the New York and Midwest ISOs, and the Electric Reliability Council of Texas (ERCOT). The dynamics of these markets may be considerably different. In less congested markets, one would expect less volatility and perhaps less of a difference between real-time and fixed-flat prices.

In the meantime, though, GSA has acted on the study's finding, along with informal assessments in other areas where its buildings are located, by pushing more of its facilities (and those of some of other federal agency customers for whom it buys electricity) toward dynamic pricing options. Whereas only 1% of its purchased load was on some form of dynamic pricing in 2011, roughly half is expected to be by the end of 2016. To address the greater volatility – particularly the prospects for losses in some years (like the two years in the study when RTP costs would have exceeded the fixed-price ones), GSA is steering most of its facilities to "block-and-index" options, most commonly one in which roughly 75% of a facilities' peak period consumption is purchased at a fixed price and any usage above that is exposed to the real-time market prices. This hedging strategy is showing positive results, preliminarily, with all facilities demonstrating at least small savings over the first year or two. As more data come in from different regions and savings are substantiated, GSA plans to increase the percentage of real-time (or day-ahead) pricing it pursues. GSA's companion buyer at the Department of Defense, the Defense Logistics Agency, has also procured more dynamically priced electricity in recent years, particularly for the U.S. Navy.

Government facilities are exceptionally well situated to take advantage of dynamic pricing because in many cases they can (because of their expected longevity) take a long-term perspective to cost control. But other types of large electricity users that expect to endure – such as hospitals or universities, for example – might also be good candidates.

In addition, there may be strategies organizations can craft to allow the good (savings) years to buffer the bad (loss) ones. GSA's election of block-and-swing options represents one hedging strategy. Another potential strategy might be the creation of escrow accounts with balances maintained to help offset the losses in bad years. This would soften the volatility inherent in the greater market exposure. Despite some risk of year-to-year volatility, the savings potential demonstrated by this study suggests strongly that any organization with substantial electric costs in states with electric choice should look closely at dynamic pricing.

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