The Importance of Marginal Cost Electricity Pricing to the Success of Greenhouse Gas Reduction Programs
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Abstract

The efficient reduction of GHG emissions requires appropriate retail pricing of off-peak electricity. However, off-peak electricity for residential consumers is priced at 331% above its marginal cost in the United States as a whole (June 2009). Even for the 1% of residences that are on some form of time-of-use (TOU) rate schedule, the off-peak rate is almost three times higher than the marginal cost. A barrier to marginal-cost based TOU rates is that less than 9% of U.S. households have the "smart" meters in place that can measure and record the time of consumption. Policies should be put in place to achieve full deployment. Another important barrier is consumer concern about TOU rate design. Two TOU rate designs (baseline and two-part tariff) are described that utilize marginal-cost based rates, ensure appropriate cost recovery, and minimize bill changes from current rate structures. A final barrier is to get residences on to these rates. Should a marginal-cost based TOU rate design remain an alternative for which residences could "opt-in," or become the default choice, or become mandatory? Time-invariant rates are a historical anachronism that subsidize very costly peak-period consumption and penalize off-peak usage to our environmental detriment. They should be phased out.

Keywords: regulation, environmental policy, electricity, marginal cost pricing, time-of-use pricing, greenhouse gas reduction, off-peak electricity rates, smart meters, smart grid, two-part tariff.

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1. Introduction

Most of the world's science and policy communities have come to accept both that the globe is warming and that this is largely caused by the emissions of greenhouse gases (GHGs) as byproducts of human commerce. Furthermore, there is recognition that any increase of more than 3 degrees centigrade by the next century poses a severe danger, perhaps catastrophic, to the world's ecosystems. Many nations are struggling to design and implement policies to prevent such an increase. To achieve this, something like a 50-80% global GHG reduction from the 1990 level is necessary by 2050. The problem is greatly complicated by its nature as a global public good: reductions in any one country do not work to cool that specific country's climate, but are a general cooling force throughout the globe. Thus the willingness of one nation to undertake costly reductions depends on the willingness of others to contribute as well. The focus here is on one important way to make the reductions less expensive—indeed, a way that is in the self-interest of countries acting autonomously. Taking up this opportunity lowers the overall reduction costs, and increases the likelihood that the reductions can be achieved within the necessary time frame.

GHG emissions are negative externalities, and corrective policies should effectively internalize them. Because the sources of these emissions are so varied, market-based policies like a carbon tax or a GHG cap-and-trade program are typically centerpieces of the recommended corrective efforts. As important as these policies are, the politics of creating such systems at more global levels have at least temporarily stalled further progress. The U.S. is a leading outlier among highly developed nations with no firm reduction goals or national cap-and-trade programs to achieve them currently under serious consideration. Nor have the extensive international efforts to forge a reduction agreement beyond the 2012 targets and 37 countries of the Kyoto Protocol yet borne fruit.

The analysis of this paper identifies a different problem that has not yet been a focus of policy debate in the GHG context, but is also crucial to the success of GHG reduction efforts. The problem is the proper pricing of electricity, apart from how its price may be affected by internalizing the GHG externality (as with cap-and-trade programs).[1] In the usual analysis of negative externality problems, the initial price of one activity (emitting GHGs) is too low relative to all other prices. But the other prices are generally assumed to be set appropriately. However, that is not the case with electricity. Electricity prices to its consumers are almost never equal to the marginal costs of providing it, and are often multiples away from the appropriate marginal cost. Failure to fix this problem can seriously impair efforts to reduce GHG emissions. The politics of such fixes are quite different, and perhaps more favorable to action, than those of global GHG agreements. Put plainly, it is in the self-interest of nations to fix this part of the problem.

A simple example can suggest the seriousness of the mispricing. One of the most promising new technologies for reducing GHGs is the electric vehicle. In California, it has been estimated that compared to conventional gasoline, using electricity to power the vehicle and move it an equivalent distance reduces GHG emissions by about 60%.[2] Since transportation is responsible for about 40% of all California GHG emissions, it is possible to achieve very substantial overall reductions simply through vehicle electrification. Of course if the cost of using electricity is much more expensive than gasoline then few consumers would choose to use it.[3] Based on current technology, several researchers have estimated "break-even" prices—for a given gasoline price, the electricity price that makes the marginal cost per mile the same. For example, Kammen et al (2008) estimate that gasoline at $5.00 per gallon is equivalent to electricity at $.10 per kilowatt-hour (kwh), at (high) battery prices of $1300/kwh.

However the actual marginal cost of using off-peak electricity to recharge a vehicle in California is only on the order of $.03/kwh, based on recent off-peak market wholesale prices. Even ignoring improving battery technology, consumers should be indifferent between using electricity and gasoline at a gasoline price of $1.50 per gallon. Since gasoline is about $4.00 per gallon at the time of this writing, off-peak electricity charging of vehicles should seem like a great bargain compared to gasoline. One problem is that virtually all residential customers are on rate schedules in which prices are the same throughout the day, and far above off-peak marginal cost. According to a FERC survey discussed in more detail later, less than 1% of California's residential consumers are on rate schedules that vary prices within a day (called here time-of-use or TOU schedules, encompassing not just simple time-of-day pricing but also more dynamic variants like real-time pricing or critical peak pricing).[4] The rates that California residences face are tiered and increase with consumption, and even the average residential rate in the year ending May 2009 was about $.15 per kwh, five times greater than the marginal cost.[5] Many of these customers face actual marginal rates of well over $.30 per kwh, or prices more than 10 times higher than a marginal cost price.[6]

To put this in a pocketbook perspective, assume a compact plug-in hybrid electric vehicle (PHEV) is driven 1000 miles per month and that half of that or 500 miles is powered by electricity. With current technology the PHEV gets about 4 miles/kwh, or it will need 125 kwhs of electricity each month. On Tier 3 of our representative rate schedule, this is $47.33 extra on the monthly electricity bill or $568 annually, whereas the off-peak marginal cost of providing it is only $3.75 per month or $45 annually. The difference in the attractiveness of these two amounts to consumers, and therefore their willingness to consider purchasing plug-in hybrids, is obvious. Huang et al (2011) show empirically that the high tiered electricity prices in California will act as a substantial deterrent to PHEV adoption, even relative to its existing TOU rates that are still well above marginal cost.

A number of questions can and should be raised about this illustrative example. Is it true that the off-peak marginal cost is only about $.03 per kwh? Wouldn't consumers simply switch to a TOU rate schedule? This paper gives more detailed answers to these questions in the U.S. context, although the answers remain as disturbing as the example and other nations likely have similar situations.

The paper proceeds as follows. In Section 2, the historical argument for marginal cost pricing is reviewed (2.1), and then evidence is presented about actual off-peak marginal costs throughout the U.S. (2.2), and actual available rate structures (2.3). This evidence suggests that, under status quo policies, there is substantial reason to be concerned about the gap between actual consumer rates and off-peak marginal costs. Then in Section 3, obstacles to marginal cost off-peak pricing are considered. Information from a useful set of surveys undertaken by FERC is reviewed (3.1) and utilized in two important dimensions. One dimension is metering issues that impede the use of TOU rate schedules, especially the important role of advanced meters and policies to speed up their deployment (3.2). Such meters make it feasible to administer TOU rates, but do little by themselves to cause consumers to want to be on these rates. Thus the second dimension concerns TOU rate design barriers (3.3), with focus on two aspects. The first aspect is the feasibility of designs that make rates closer to marginal costs and are perceived as fair by consumers, and two methods to achieve these are discussed (3.3.1). The second aspect is to consider the question of consumer options: whether an appropriate marginal-cost based TOU rate structure should be an available alternative if a residence chooses to “opt-in”, the default alternative unless the residence “opts out,” or mandatory (3.3.2). Finally, Section 4 provides a summary and conclusions.

2. Is There Really a U.S. Problem of Mispriced Off-Peak Electricity?

2.1. The Historical Argument for Marginal Cost Electricity Pricing

Long before global warming became a known issue, economists have pointed out the inefficiency caused by the mismatch between electricity’s rates and the highly variable marginal cost of providing it. The 20th century argument was usually in the context of rates set approximately at average cost (under rate-of-return regulation), whereas actual marginal cost during peak periods was well above this average, and actual marginal cost during off-peak periods well below the average. This rate structure resulted in the building of many high marginal cost plants designed only to operate during peak periods, with substantial unused capacity during the off-peak. There was inefficient overconsumption of electricity during the peak, and inefficient underconsumption during the off-peak. TOU prices, on the other hand, would give consumers incentive to reduce these inefficiencies by conserving more during peak periods and shifting load to off-peak periods.[7]

This argument met resistance from the regulated utility world on two practical grounds: existing meters were not smart enough to distinguish time-of-day let alone real-time variations, and electricity consumers preferred the simple system where they did not have to pay continual attention to the timing of (and varying rates for) their electricity consumption. We have come to understand the metering question as a transaction cost that had been assumed away in the early argument, and the consumer behavior question as one for the rapidly-developing area of behavioral economics with consumers characterized by bounds on (and often distaste for) calculating.

The more practical economists did not give up in the face of this resistance; rather they attempted to address it. It was true that existing electromechanical meters could not be used in conjunction with TOU rates, but it was not impossible to build meters that could be so used. They were expensive, but the benefits would outweigh the costs for larger customers. Similarly, even if most residential households did not want to be bothered with electricity plans that required more ongoing attention from them, surely larger plants with energy management departments would be interested in opportunities to reduce their electricity expenses through more efficient rate plans. So the use of TOU rate plans began to spread, but limited primarily to the industrial and larger commercial electricity consumers. There was also a response to the behavioral problem that customers do not like the threat of very high real-time rates that are sometimes observed in wholesale market prices on unusual days. Interruptible rate plans (now often called “demand response” programs) that offered consumers lower normal rates in return for willingness to shed load during the unusual days also had some success in a number of jurisdictions. The behavioral genius of this plan is to reward those who conserve during peak periods, rather than to penalize those who do not conserve. Again, these were primarily used by larger customers but also included some residences that agreed to reduce air conditioner usage.

If we fast forward to the 21st century, metering and control technology have advanced greatly. Smart, reliable electricity meters that can tell time and can go not only forwards but backwards are available at no higher cost than the older-style mechanical meters.[8] Computer programs and other inexpensive control devices are available to respond automatically to increases in electricity rates and adjust electricity usage in accordance with the prior instructions of the user. Both the transaction cost and behavioral arguments against TOU rates have been substantially weakened by these technological advances.

For many economists, the old 20th century argument updated with 21st century technological advances is sufficient grounds for pushing anew for increased use of TOU rate structures, and preferably the more sophisticated kind like real-time pricing or approximations of it. Borenstein (2005), for example, shows that substantial welfare gains would arise from increased use of time-varying rates in competitive electricity markets, even with quite small price elasticities of demand.

Even the updated version of the old argument emphasizes gains that come primarily from reducing loads during the peak periods.[9] This is because these demands can be so expensive to fulfill, because they threaten the reliability of the grid for all users, and because demand reduction during these periods mitigates the threat of harmful exercise of market power (a feature that might have made a difference in the California electricity crisis of 2000-2001[10]). These are all valid and important arguments, but another layer must be added to them: <u>the social gain from increased use of off-peak electricity as a</u>

GHG-reducing response. That is, in some cases off-peak electricity can power something—serving as a substitute for another power source—and do so at lower social cost precisely because it reduces GHG emissions. This may help the "peak" problem of capacity that goes unused much of the time in a surprising way, by expanding off-peak demand and thus reducing the differential between peak and off-peak. However these opportunities will not be taken up to anywhere near the extent that they should if off-peak electricity is priced substantially above its marginal social cost. The important example of vehicle electrification has already been given, but there may be many other opportunities for this type of substitution. Suppose, for example, inexpensive and abundant wind power supplies become available at night, meaning relatively few GHG allowances must be used for this off-peak supply. This further reduces the off-peak marginal cost relative to alternative fuel options (including but not limited to on-peak electricity), and some activities now using alternative fuel sources may shift to off-peak electricity if priced at its marginal cost. Another opportunity is if battery storage technology continues to improve, so that off-peak electricity can be economically stored for later peak usage.

2.2. What Exactly is the Marginal Cost of Off-Peak Electricity?

The earlier California example referred to an off-peak marginal cost of $.03 per kwh based upon wholesale prices. The relevant short-run marginal cost is the extra cost necessary to deliver an additional kilowatt-hour of electricity to a customer at a particular time and location. In many parts of the country, where wholesale prices are set by competitive electricity markets, the Independent System Operators (ISOs) keep track of these prices as delivered to particular points on their grids; these are referred to as locational marginal prices (LMPs). These prices depend primarily on the fuel cost at the marginal electricity plant generating the power (e.g. coal, natural gas, nuclear), and they vary around the country at any single time as well as varying over time at any single location due to fuel price changes. These prices also take into account any congestion and line losses that arise between the generator and the receiving electricity distributor.

Of course the retailer's prices to its consumers must fully recover all of its costs for the operation to be viable. However, substantial portions of the cost are not marginal—e.g. they include reimbursement for the sunk costs of investments made long ago, like plant construction costs and the costs of the wiring for distribution. Allowed cost recovery also may depend on contracts signed long ago for delivery of electricity at fixed prices, also a sunk cost. Because these sunk costs have historically been a large portion of the total allowed cost, recovery of them by pricing at average cost rather than marginal cost has characterized pricing in regulated sectors. But these prices do not give the correct signals to consumers about the cost of additional consumption. This has been a major bone of contention between economists seeking more efficient prices (closer to marginal costs) and managers of the regulatory practice wanting an easy-to-administer system.

Much work has been done by economists to devise workable pricing plans for regulated settings that allow for cost recovery but have prices closer to marginal costs. Higher revenue during peak periods tends to offset the lower revenue during off-peak periods, but in general they will not balance out simply by charging marginal cost and some adjustment is needed to meet the overall revenue requirement. A promising method for practical application, including the off-peak problem that is the focus here, is that of the "two-part tariff".[11] With this method, all rates (think both peak and off-peak) are set at short-run marginal costs, and the residual amount still necessary for full cost recovery is assessed as a fixed fee (spread over all consumers). Payment of this fixed fee is mandatory for using the system, but it need not be the same for all customers. It has been shown earlier (Friedman and Weare 1993) that this fixed fee can be set by dividing customers of a certain class (e.g. residential) into 5-6 consumption groups from low to high levels, each group with its own fixed fee representing its share of the non-marginal costs, and that these fees can be set so that virtually all customers experience little to no aggregate bill changes at their current consumption levels.

Assuming for now that this method can be used with marginal cost prices to meet the overall revenue requirement, are there are other costs besides the LMP that may be additional short-run off-peak marginal cost components? There are basically two categories here, discussed in turn below: ancillary services used to ensure grid reliability and balance, and any marginal distribution costs incurred to move the electricity from the door of the receiving utility (where the LMP ends) to the ultimate consumer.

The cost of ancillary services is also reported by the ISOs, although it is not clear how much if any of these costs are incurred by incremental increases in off-peak demand (e.g. the cost of maintaining reserve margins). For example, data from the New England ISO wholesale cost report for April-June 2009 in Connecticut shows that the average off-peak LMP was \$.0321/kwh.[12] The same table shows a total wholesale cost of \$.0401. However, almost all of the difference is due to a capacity payment that averages to \$.0078/kwh but is clearly described as Connecticut's share of a monthly payment based on the system-wide peak from a year earlier. None of this should be billed or attributed to off-peak hours.[13] With the capacity payment removed as nonmarginal, the marginal cost including all ancillary services is \$.0323/kwh (barely distinguishable from the off-peak LMP). In general for the New England ISO, these off-peak ancillary costs are usually below 3% of the LMP, and we add 3% to approximate them here.

Similarly, the marginal cost at the retail level is simply the marginal wholesale cost plus marginal distribution charges. However, most of the distribution expenses are nonmarginal; they are the fixed costs of the low-voltage wire system, its maintenance, and the administrative costs of meter reading, billing, and other service changes. They are similar to local land-line telephone service, for which almost all revenue is collected through a fixed monthly fee. The full average of all distribution expenses is on the order of \$.017 nationwide.[14] Perhaps the only clearly identifiable off-peak marginal cost is the line loss in going from entry to exit of this system, which varies but is usually on the order of 6-7%, or \$.002/kwh (ISO New England 2009). To be conservative, let us assume that 10% of the LMP (\$.003/kwh in this case) can be considered marginal distribution expenses. This brings our estimated off-peak marginal cost for Connecticut to \$.0363, having added 13% to the LMP to account for marginal ancillary services and distribution expenses.

Table 1 column (1) presents estimates of the off-peak marginal costs for April-June 2009 in each of the 50 states and Washington, DC. For those 34 jurisdictions served by ISOs, data analogous to that used in the example above was used: the off-peak LMP, plus 13% to approximate the marginal ancillary services and distribution cost. The average estimated off-peak marginal cost for this group is .02767 cents/kwh. For the 17 jurisdictions not served by ISOs, somewhat rougher data was used. The North American Electric Reliability Corporation (NERC) has average wholesale price data for each of its nine regions, but not broken into peak and off-peak. For each ISO state, the percent that the (previously calculated) off-peak marginal cost is to that state's NERC wholesale data was calculated using its relevant NERC region; the average of these is 51.1 percent. Off-peak marginal costs for the non-ISO states were then estimated by applying this percentage to the available NERC wholesale data for each state's region. This yielded an average U.S. off-peak marginal cost estimate of .02794.[15] These averages of course contain considerable variation, with a high of .03627 in Florida and New York, and a low of .02076 in the states served by the Midwest ISO.

These estimates are heavily dependent upon fuel prices that in 2009 declined from unusually high levels in 2008. For comparison purposes, we present in Table 2 the 2003-2010 annual average off-peak marginal cost estimates for residences in the PENELEC zone (western Pennsylvania) of the PJM system. These are the simple average off-peak LMP prices for this zone, plus 13% as before. Over the past eight years, the average off-peak marginal cost has been between \$.03 and \$.05 per kwh, except when it rose to \$.06 in 2008 before returning in 2009 to the lower part of its historically more typical range.

Table 1: Off-Peak Marginal Costs of Electricity and Actual Rates, April-June 2009, by State

State	(1) Off-peak Marginal Cost (2007 NERC data)	(2) Off-peak Marginal Cost (2009 ICE data)	(3) Average Residential Electricity Price June 2009	(4) Percent (3)>(2)	(5) June 2009 TOD Off-Peak Rates	(6) Percent (5)>(2)
Alabama	2.820	2.857	11.060	292	6.926	146
Alaska	3.611	4.091	17.550	386	6.140	70
Arizona	2.593	2.504	11.270	335	5.018	93
Arkansas	2.209	2.209	9.630	336	4.403	99
California	2.240	2.240	15.010	570	18.826	741
Colorado	2.593	2.504	9.970	284	6.370	146
Connecticut	3.228	3.228	20.890	547	16.931	425
Delaware	3.236	3.236	14.870	359	5.416	67
Florida	3.627	4.494	12.170	236	8.835	144
Georgia	2.820	3.235	10.850	285	8.025	185
Hawaii	3.611	4.469	22.200	515	17.332	380
Idaho	2.593	2.881	8.310	220	5.100	97
Illinois	3.236	3.236	11.420	253	5.592	73
Indiana	3.236	3.236	9.640	198	3.621	12
Iowa	2.482	2.708	10.810	336	6.431	159
Kansas	2.209	2.209	10.160	360	7.411	235
Kentucky	3.236	3.236	8.440	161	6.693	107
Louisiana	2.209	2.209	7.860	256		
Maine	3.122	3.122	15.250	388	12.681	306
Maryland	3.236	3.236	15.920	392	9.507	194
Massachusett	3.246	3.246	17.970	454	12.459	284
Michigan	2.076	2.076	12.620	508	4.243	104
Minnesota	2.076	2.076	10.450	403	6.080	193
Mississippi	2.209	2.209	10.370	369		
Missouri	2.209	2.209	9.810	344	5.480	148
Montana	2.482	2.708	9.360	277	6.501	162
Nebraska	2.209	2.209	9.780	343		
Nevada	2.593	2.881	12.020	364	7.554	191
New Hampshir	3.203	3.203	16.630	419	12.028	275
New Jersey	3.236	3.236	16.880	422	5.257	62
New Mexico	2.209	2.209	10.370	369	7.705	249
New York	3.627	3.627	19.540	439	4.767	31
North Carolina	3.236	3.236	10.120	213	4.562	41
North Dakota	2.076	2.076	8.810	324		
Ohio	2.076	2.076	11.380	448	5.188	150
Oklahoma	2.209	2.209	8.460	283	5.240	137
Oregon	2.593	2.504	9.040	249	7.161	176
Pennsylvania	3.236	3.236	12.480	286	6.842	111
Rhode Island	3.260	3.260	16.200	397		
South Carolina	2.820	2.857	10.420	270	8.367	197
South Dakota	2.076	2.076	9.200	343	4.750	129
Tennessee	3.236	3.236	9.360	189	2.755	-15
Texas	2.752	2.752	12.930	370	9.071	230
Utah	2.593	2.504	9.120	252		
Vermont	3.220	3.220	15.280	375	6.864	113
Virginia	3.236	3.236	11.230	247	4.932	52
Washinton	2.593	2.504	7.940	206		
Washington, D	3.236	3.236	13.910	330	15.655	384
West Virginia	3.236	3.236	7.950	146	2.896	-11
Wisconsin	2.076	2.076	12.550	505	6.645	220
Wyoming	3.192	2.504	9.160	187	3.650	14
AVERAGE	**2.794**	**2.844**	**11.910**	**326**	**7.452**	167

Table 2
Average Off-Peak Marginal Cost, 2003-2010
PENELEC Zone of PJM[a]

Year	Average Off-Peak MC
2003	.033
2004	.037
2005	.049
2006	.045
2007	.046
2008	.060
2009	.036
2010	.042

[a]These estimates are derived from the simple-average off-peak LMPs reported by PJM, plus 13% to account for the additional marginal costs necessary to deliver the electricity from the receiving distribution company to its customers. The PJM data comes from its annual State of the Market reports.

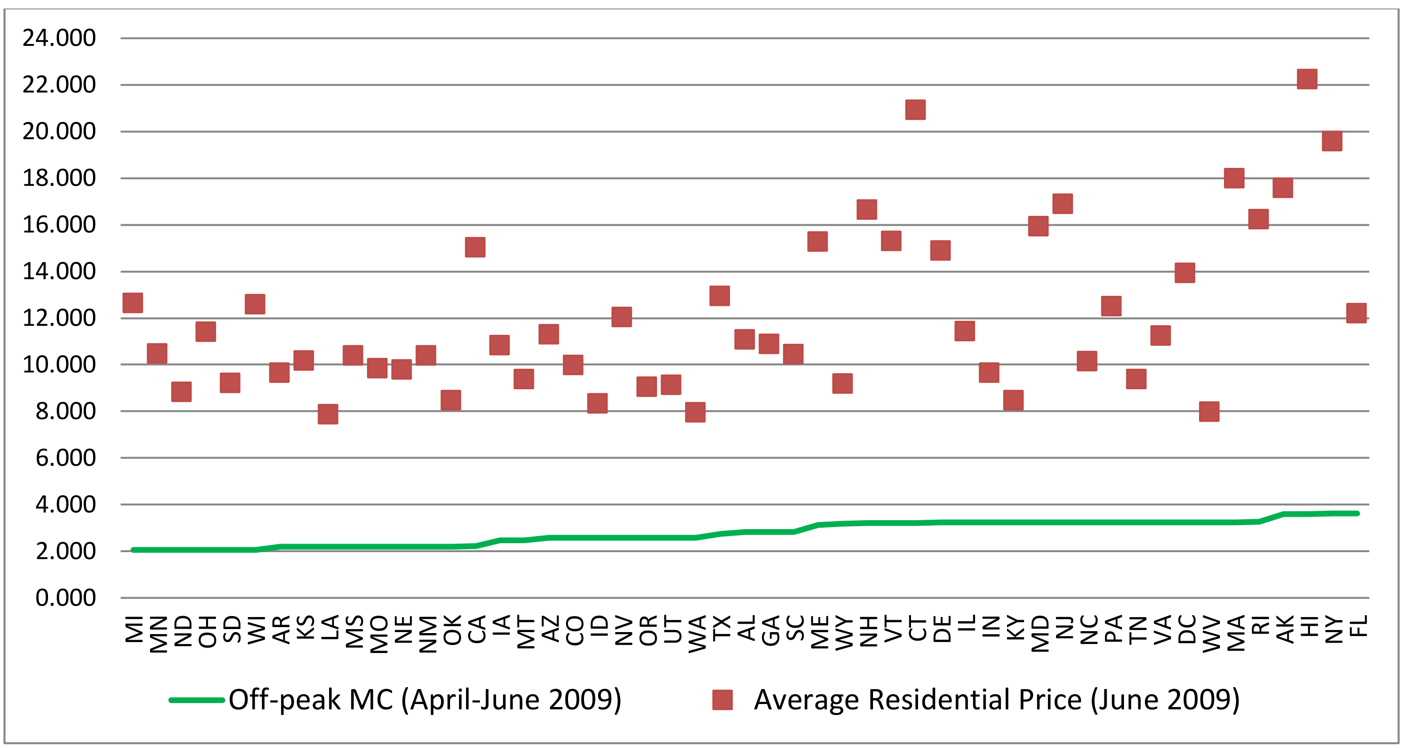
The point of this section is that appropriate off-peak rates for electricity should be based upon its marginal costs. In 2009, these marginal costs were around \$.03 per kwh in most of the country, although they were as low as \$.02 and as high as \$.04 depending upon location. How do they compare to the rates being charged?

2.3. How Close Are Actual Rates to the Off-Peak Marginal Costs?

The next part of our task is to see how close actual retail off-peak rates are to the off-peak marginal costs. There are two distinct parts to this task. One is to compare the actual rates that residential consumers face with the marginal costs. However, this comparison takes as a given the rate structures that consumers are on. Almost all of the consumers are on the standard rate structures that do not vary with time, and they could if motivated switch to a TOU schedule that would have lower off-peak rates. However there are numerous obstacles and barriers reviewed below that deter residential consumers from this. These include <u>meter availability</u>, <u>disincentives due to regulation</u>, and <u>consumer resistance due to behavioral economic factors</u>. The effects of these might be called <u>the obstacles gap</u>. <u>An additional rate gap would then be defined as the amount by which available TOU rates exceed marginal costs</u>, and we consider later policies that might change the rate structure to reduce any such gaps.

Because almost all residential consumers are on time-invariant rates, average electricity rates in each state are a good proxy for rates that customers actually face.[16] We show the average residential rates in effect for June 2009 in column (3) of Table 1, and have calculated in column (4) the percent that these average rates exceed the off-peak marginal cost. These are also shown in Figure 1 along with the off-peak marginal cost data, with the data arranged from least to greatest off-peak marginal cost. The average residential rate for the U.S. as a whole is 12.05 cents per kwh, which is 331 % above the average off-peak marginal cost of 2.79 cents per kwh.[17] There is considerable variation in these "mark-ups" by state, with our estimates showing the lowest mark-up of 145% in Washington DC and the highest mark-up of 766% in Michigan (followed closely by Idaho's 756%).

Figure 1: Average Residential Electricity Rates and Off-peak Marginal Costs by State (cents/kwh)



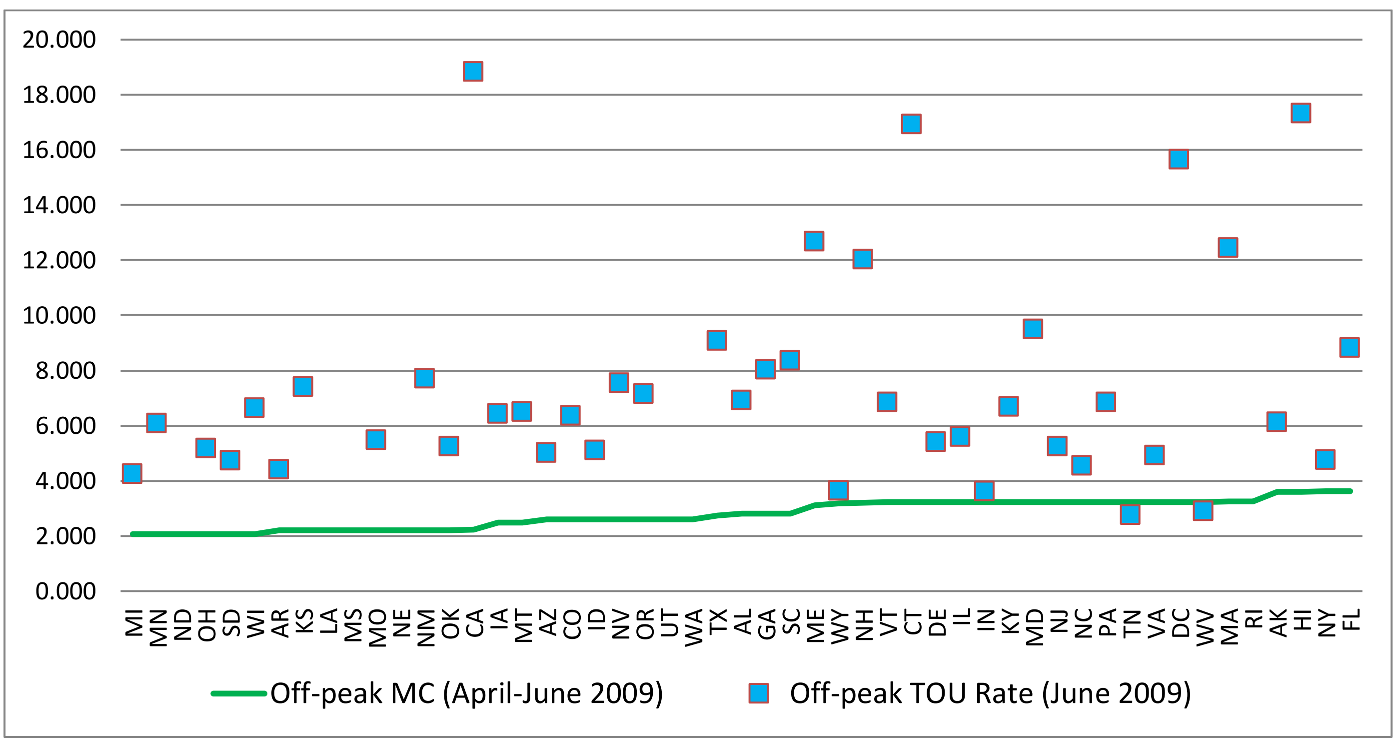
Again, this is not to say that electricity sellers are collecting too much revenue in total; these rates are almost always the result of a process (whether competitive or regulatory) intended to provide an appropriate overall industry rate-of-return. However, today's consumers face highly inappropriate rates and incentives for consuming off-peak electricity, and such rates inappropriately discourage anyone thinking of buying an electric vehicle like a plug-in hybrid and recharging it during off-peak hours. Of course, if these consumers were able to switch to a TOU rate schedule, the story might be different.

Column (5) of Table 1 lists the off-peak rates in effect in June 2009 at 50 utilities or retailers, chosen largely from those who had participated in the 2008 Demand Response and Advanced Metering survey undertaken every two years by the Federal Electricity Regulatory Commission (FERC).[18] However, this subsample focuses on entities that serve suburban populations, and that offer residential TOU rates. For a few states in which utilities in the FERC survey reported no TOU programs, we looked for other utilities in the same state that did have such programs. However, in 7 states neither FERC nor we identified utilities with residential TOU rates available in June 2009.[19] In one case (Maryland), FERC's only utility with residential TOU served a rural population, and we substituted a utility serving a suburban population. When there was more than one utility in a state with TOU programs, we chose the one near the largest city that included a suburban residential area in its service territory. It would be difficult for this subsample to be very different from the U.S. residential population as a whole, but it does give somewhat higher weight to the suburban areas that should be prime targets for electric vehicles (many vehicle commuters, many garages convenient for night recharging of electric vehicles).[20]

The result of this exercise is that our estimate of the average off-peak residential TOU rate for the U.S. as a whole is 7.452 cents/kwh, almost three times higher than our 2.794 cents/kwh estimate of the off-peak marginal cost for the same period. This is not just a problem that rates may lag behind marginal costs: it is also substantially higher than average off-peak marginal costs for any year from 2003-2009, if our earlier estimates of 3-5 cents from PJM are representative. Of course there is considerable variation by jurisdiction. Figure 2 shows these rates graphically, again along with the corresponding off-peak marginal cost estimate from that state. Indiana, Tennessee, West Virginia and Wyoming all had utilities with rates that were within 15% of our current estimated off-peak marginal cost for them. Of the other 40 jurisdictions, another 10 were within 100% of estimated marginal cost. That leaves 30 with rates that are at least two times higher than marginal cost. California, still suffering consequences from its 2000-2001 electricity crisis, is the worst at 741% above marginal cost. It is followed by Connecticut (425%), Washington DC (384%), Hawaii (380%), and Maine (306%).

This exercise shows that it is not enough simply to get consumers off of the standard plans and on to TOU plans. In answer to the question asked by this section: Yes, there is a problem of mispriced off-peak electricity, and it is not a minor one when prices are routinely above competitive (marginal cost) levels by more than 100%. The TOU plans themselves need to be reformed so that off-peak rates are kept much closer to actual off-peak marginal costs. But what problems might there be in getting consumers on to TOU plans?

Figure 2: Time-of-Use Rates and Off-peak Marginal Costs by State (cents/kwh)



3. The Obstacles Gap

This section begins with the results of the FERC survey and discusses physical metering issues that prevent TOU rates from being offered. Then regulatory obstacles that further retard or deter the use of TOU rates are discussed. Finally, consumer behavior issues that lead to resistance to TOU rates are considered.

3.1. The 2010 FERC Assessment of Demand Response and Advanced Metering

The U.S. Energy Policy Act of 2005 requires that FERC publish an annual report assessing U.S. electricity demand response resources, including penetration rates of advanced meters and time-based rate programs. FERC implements this by conducting a survey every other year, and reviewing industry activities and regulatory actions during the non-survey years.[21] The advanced meters are informally referred to as “smart meters” and more formally as “advanced metering infrastructure” (AMI) meters. While the penetration rate of these meters is increasing, in 2010 it was only 8.9 percent of residential meters (up from 4.7 percent in 2008).[22] However, only 1 percent (1.1 million of 128 million residential electricity customers in the U.S.) are on some form of TOU rates, so that very few of these AMI meters are yet being used to encourage price responsive behavior. Rather, they are being used to improve customer service in other ways like faster outage detection and restoration.

The life expectancy of AMI meters is in excess of 20 years, and their costs are not very different from the older meters; the Electric Power Research Institute reported that they averaged $75 per meter during 2005-06.[23] However, to make full use of these advanced meters usually requires a new communications infrastructure, and there are also one-time installation costs, project management, and other information technology integration costs. According to EPRI and FERC(2006), this typically adds $125-

$150 to the average cost of an AMI upgrade per meter (or $200-$225 per meter in total installation expenses).

Given the limited number of meters in place that are even capable of measuring consumption by TOU, it is not surprising that very few residences are on TOU programs. We have used the FERC survey data to calculate, for each state, the percent of residences that are on any type of TOU program (including the more sophisticated variants like critical peak pricing and real-time pricing). For the U.S. as a whole in 2010, only .9 percent of residences are on time-varying plans. While there is of course variation by state (Table 3), the only state that exceeds 3% in the FERC data is Arizona with 28%. Interestingly, the Arizona energy providers generally offer customers choice from multiple time-varying plans. For example, the Salt River Project offers one plan with peak hours defined as 1-8PM weekdays, and another plan with peak hours defined much more narrowly to 3-6PM weekdays. In May-June, the broader-peak plan charges 19.15 cents/kwh on peak, and 6.63 cents off-peak (roughly a 3 to 1 ratio). But the narrower-peak plan charges 29.77 cents/kwh on peak, and 7.79 cents off-peak (roughly 4 to 1).

Table 3: Estimates of the Percentage of Residences on Time-Varying Electricity Rates in 2010, by State

State	Percent on TOU Rates
Alabama	.02
Alaska	.00
Arizona	28.44
Arkansas	0.00
California	0.14
Colorado	0.35
Connecticut	0.01
Delaware	0.00
Florida	0.12
Georgia	0.07
Hawaii	0.00
Idaho	0.01
Illinois	0.16
Indiana	0.68
Iowa	1.27
Kansas	0.03
Kentucky	0.11
Louisiana	0.00
Maine	0.04
Maryland	1.87
Massachusetts	0.00
Michigan	0.15

Minnesota	0.01
Mississippi	0.00
Missouri	0.02
Montana	0.00
Nebraska	0.01
Nevada	0.32
New Hampshire	0.09
New Jersey	0.39
New Mexico	0.16
New York	1.92
North Carolina	0.71
North Dakota	0.00
Ohio	0.77
Oklahoma	0.08
Oregon	0.00
Pennsylvania	0.02
Rhode Island	0.00
South Carolina	0.12
South Dakota	0.01
Tennessee	0.00
Texas	0.00
Utah	0.00
Vermont	2.21
Virginia	0.04
Washinton	0.00
Washington, DC	0.19
West Virginia	0.49
Wisconsin	0.21
Wyoming	0.06
U.S. Average	**.88**

The FERC survey, while the best available evidence on these developments, does have some reliability issues and was not designed to produce accurate numerical results by state. While it requests data from virtually all U.S. entities (n = 3358) providing electricity service, only 52% of these responded to the survey. Nevertheless, FERC reports that the respondents cover over 77% of all electricity meters in the U.S., and that it finds no evidence of selection bias in the results. Still, we caution against using our state-by-state comparison as anything other than a rough indication.[24]

Thus <u>if it is important for residential customers to face off-peak rates equal to off-peak marginal costs, perhaps the most serious obstacle is metering: such rates cannot be charged if the customers do not have meters that record off-peak consumption</u>.

3.2. Activity to Increase the Number of AMI Meters

By itself, the low number of AMI meters actually installed gives a false impression of the country's ability and perhaps willingness to move to a much greater reliance on time-varying electricity pricing. Provisions to encourage advanced metering were included in the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007, the Emergency Economic Stabilization Act of 2008 (the "bailout" bill), and the American Recovery and Reinvestment Act of 2009 (ARRA). The provisions of the 2005 and 2007 Acts largely encouraged states and their electricity providers to consider smart grid investments (including smart meters) favorably, but the 2008 bailout bill included a modest financial incentive: it reduced the smart meter depreciation time for tax purposes from 20 to 10 years. Some utilities and state regulatory commissions have acted to further the advanced metering goal. In particular, in recent years a number of places have acted quite vigorously to increase the presence of AMI meters. For example, three multistate utilities (Southern Company, Duke Energy, and Pepco Holdings) intend to deploy them throughout their systems.[25] These early planners were in excellent position to take advantage of the $3.4 billion Smart Grid Investment program that was appropriated under ARRA; DOE awarded all of these funds over the summer of 2009.[26] However there are substantial lags from the time a decision is made to upgrade meters until the actual upgrading is complete. A few examples will be instructive.

California utilities are under orders from the California Public Utilities Commission (CPUC) to install AMI meters for 100% of their residential customers. PG&E was the first to receive this order with approval of its application to fulfill it on July 20, 2006. This was preceded by authorization for a brief six-month "pre-deployment" phase, but the purpose of this was not for testing alternative AMI configurations as PG&E had already made decisions about this. The original order specified full deployment was to be done over the next five years. In response to its original order, PG&E proposed and received approval largely for retrofitting its existing meters with communications devices. But several years later PG&E rethought its original decision. It requested and in March 2009 the CPUC approved modification of the original order to take advantage of recent technological improvements, and it changed from retrofitting to fully replacing each meter with a solid-state AMI meter.[27] In Bakersfield, one of the first areas with the new meters, there has been public concern voiced about their accuracy after some consumers complained of unusually high bills from the summer; these concerns have not been validated, but they create pressures for further testing and deployment delays.[28] According to the FERC survey data, by 2010 only 41.6% of PG&E metered residential customers had AMI meters.

Because this is a relatively new concept with technology that has been rapidly changing and improving, it is a somewhat similar problem to those of the 1980s and 1990s of bringing personal computers and then the internet into large organizations for the first time: there are many promising applications but nobody is quite sure exactly which of them (or which new additional ideas) will be used, and future technology could cause rapid obsolescence for the adopters of the early versions. So it is sensible in many cases to begin with preliminary testing and then pilot projects in order to try out particular versions before large orders for meters are placed. That is why SDG&E and SCE, the two other California utilities that received their orders somewhat after PG&E, have proceeded somewhat more slowly and by the time of the 2010 survey report had far less AMI coverage: 16.2% of residential meters for SDG&E, and only 3.3% for SCE.[29]

A second example of an active state is Connecticut, which in 2006 mandated that all electricity customers be placed on TOU service. Of course before this can happen, appropriate meters must be installed. The Department of Public Utility Control (DPUC) directed its utilities to prepare metering plans that would allow for the phase-in of these meters. Using Connecticut Light & Power (CL&P) as illustrative, it filed a plan in 2007 that would meet the requirement by replacing its 1990s AMR system with new AMI meters that it would phase-in over an 18-month period beginning January 2009. Later in 2007, the state legislature enacted a bill requiring CL&P to deploy an “advanced metering system,” that supports net metering and tracks hourly consumption.[30]

CL&P filed a revised plan to be in compliance with this legislation. DPUC, however, had concerns about the rapid deployment of an expensive new technology with no track record to prove its worthiness. It was concerned about an apparently large cost differential between using AMR meters at $125 each that it thought might be able to satisfy all mandates or AMI meters at $1000 each.[31] It only authorized two AMI pilot programs, of which the larger is called the “10,000 meter test,” and said that it would not decide about any further AMI deployment until the results of that test are in and hearings are held to review it. In March 2010, CL&P filed its test results with DPUC and recommended full AMI deployment to begin in 2013, subject to rulings on other filings that cover issues like cost recovery. This issue is still pending.

The point of these examples is that it takes considerable time to plan and implement a new AMI metering system for large numbers of customers. While this time will be reduced with experience and maturity of the technology, right now it seems to require more than five years (beginning with the planning) for large systems. FERC does report planned deployments of these meters over the next 5-7 years as reaching almost 52 million, about 36% of the 145 million meters in total (including commercial and industrial meters). Another FERC staff report estimates that even with some (unspecified) expansion from “business as usual” to stimulate AMI deployment, it would still only expect this deployment rate by 2019 to average 40% nationwide and to exceed 60% in only thirteen states.[32]

In addition to California and Connecticut, some other states are taking action to speed up the deployment of smart meters beyond the required encouragements of the 2005 and 2007 energy acts.

The Texas legislature, for example, in 2005 directed its PUC to authorize electric delivery companies to assess a surcharge to recover the cost of smart meters. The PUC reports that deployment is beginning voluntarily, but it also requested that the legislature authorize it to require smart meter deployment.[33] This authorization has not occurred, although voluntary deployment of AMI meters has been encouraged and at the time of the 2010 FERC Survey covered 11.7% of customers. In Pennsylvania, the General Assembly directed electric distribution companies with more than 100,000 customers to file smart meter procurement and installation plans for approval by the Pennsylvania PUC, and the PUC has clarified the standards that such plans must meet.[34] In April 2010, it approved the deployment plans of three of its utilities. However, these plans do not envision wide-scale deployment beginning before 2017 (with completion by 2022).[35] Other examples from other states could be given[36], but absent some type of strong further inducements, the deployment of smart meters seems unlikely to cover even half of U.S. households by 2020. This simply may not be fast enough to enable the type of GHG reductions achievable by substituting off-peak electricity for gasoline and diesel fuel through vehicle electrification, let alone all the other sources of benefits expected from AMI and time-varying rates.[37] More aggressive actions should be considered. These actions should focus on broadening the number of jurisdictions working to implement AMI, rather than trying to hasten any single jurisdiction's deployment. We have seen good reasons why this will remain a 5-year process or longer during the next decade. Nevertheless, there can be substantial gains achieved by encouraging the jurisdictions less active now to become "fast seconds" by quickly following the AMI pioneers of today.[38]

3.3. TOU Rate Design Barriers

The beginning of this article explained that there is a long history and a long consensus among economists that time-varying rates are more efficient than the time-invariant rates that apply to 99% of U.S. households. Starting from time-invariant rates, a switch to time-varying rates can be done in a way to make everyone better off. This is simply because the cost of peak electricity exceeds the price the customer is being charged, and correspondingly the cost of off-peak electricity is below the price charged.

To see this, start from the idea that bills at the initial consumption point can remain unchanged (at the combination of peak and off-peak consumption that the customer is using). However, now offer time-varying rates that apply only to changes from this starting point. Let the peak rate be above the current average cost rate, even if below marginal cost. Some consumers, now being offered a bigger bill reduction in return for reducing their peak consumption, will find it to their advantage to cut peak consumption. The utility pays them more for this than it would under the time-invariant rate, but less than the marginal cost they are avoiding. So both the consumer and the utility are better off, no one worse off. Similarly, let the off-peak rate be at a price lower than average cost, but still above the actual marginal cost. Some consumers will now find it to their advantage to increase off-peak consumption, paying the utility less than if under time-invariant rates but still more than the utility's cost of providing the additional off-peak units. Again, the consumer and the utility are both made better off, no one worse off. So time-varying rates are more efficient than time-invariant rates. Further, any time the rates are not at the actual peak and off-peak marginal costs, there is room for a deal (analogous to the above reasoning) that makes everyone better off by moving the rates closer to actual marginal costs. The most efficient rates are at prices equal to marginal costs.

In fact, an actual rate design very similar to the above description has been in voluntary use by commercial and industrial customers of Georgia Power. It is a real-time pricing rate design because it has prices that change every hour, but each customer is also given a baseline based on historic consumption for each hour and the real-time prices are only applied to changes from that baseline. In other words, this "baseline" method sets the bill at current average cost if consumption is at the baseline, and only applies marginal-cost based rates to the deviations from the baseline to determine the final bill. While this particular program is popular, time-varying rate programs for residential customers are another matter. Many of these consumers are uninterested in or opposed to time-varying rates. There are two essential types of reasons for this: (1) poor time-varying rate designs that actually can make substantial numbers of consumers worse off, even if many or most are made better off; and (2) behavioral economic factors that cause many consumers to stick with the status quo even when there are alternatives that would make them better off. Both types of factors must be satisfactorily addressed if we are to realize the GHG reductions and other potential gains from having off-peak rates at marginal costs.

3.3.1 Better time-varying residential rate design.

The main thrust of this article is that off-peak electricity rates must be reduced to the off-peak marginal costs. This thrust avoids much important discussion that has largely already occurred about peak-period pricing, and in particular the value of allowing more dynamic time variation than simple time-of-day pricing (e.g. critical peak pricing, real-time pricing). However to address common distributional concerns, in addition to the “baseline” method of rate design described above, it may also be beneficial to illustrate how the two-part tariff idea can be used.

For any given peak and off-peak marginal costs per kwh, one could calculate the pure marginal cost revenue (*MCR*) at the old consumption levels (similar to what is done in many PUC rate proceedings, in which proposed new rates are examined by seeing their implications when applied to the past year’s consumption levels).[39] Because there are non-marginal costs incurred and entitled to cost recovery, *MCR* will usually be less than total allowed revenue (*TAR*). One way to use the two-part tariff idea is to assess an additional fixed cost per customer (*FC*) chosen to make up the revenue difference. If there are *n* customers, this means:

$$FC = (TAR - MCR)/n \tag{1}$$

The important efficiency property of the fixed part of the system is that it be a charge that does not affect the consumer's behavior (an incentive for which there is no response). Virtually all residential customers regard it as a necessity to remain connected to the electricity system (i.e. the only way to avoid the fixed charge is by going completely off the grid). The problem with the above method is a fairness issue: both small and large customers would pay the same fixed cost, even though they have not been charged this way in the past. Furthermore, to the extent that smaller customers tend to be the least well-off and vice versa for the largest, this is a regressive method.

The way out of this is to recognize that all customers need not have the same fixed cost. If we think of the fixed cost as an assessment for the customer's fair share of infrastructure costs, this could rationally be assessed in rough proportion to long-term, historical consumption (again, something that is essentially unalterable by changes in short-run consumption behavior). A simple procedure to do this would be to divide residential consumers into approximately 5 equal-sized groups based on average annual consumption over the past few years, and then set a fixed charge for the households in each group such that the charge rises as one progresses to the higher-consuming groups. More generally for k groups, we set FC_1, FC_2, …, FC_k such that $FC_1 < FC_2 < \ldots < FC_k$, and

$$FC_i = (TAR - MCR - (\textstyle\sum_{j \neq i} n_j FC_j))/n_i \qquad \text{for } i = 1,2,\ldots k \qquad (2)$$

where n_i is the number of customers in group i.

If the fixed fee rises proportionately with the group's average consumption $\bar{Q}_i$, then the following relation will hold:

$$FC_i/FC_j = \bar{Q}_i/\bar{Q}_j \qquad \text{for all } i, j \qquad (3)$$

Equations (2) and (3) will solve for the FC_i for any group definitions given values of the other parameters (n_i, $\bar{Q}_i$, TAR, MCR).

However, the proportionality rule (3) may not correspond to what in practice is considered equitable. A different rule is "status quo equity" that assumes the distribution is fair in the current system, and tries to minimize any bill changes caused by a switchover to a different rate design. This is equivalent to assigning each group its own TAR_i (the total revenue group *i* contributes under the status quo) and then:

$$FC_i = TAR_i/n_i - MCR(\bar{Q}_i)) \qquad \text{for all } i \qquad (4)$$

where $MCR(\bar{Q}_i)$ is the marginal cost revenue at the average consumption level in group *i*. Since *MCR*(*Q*) is linear in *Q*, equation (4) for all *i* ensures that equation (2) holds.[40] Then the bill for the average consumer within each group is identical to its historical level at historical consumption, and because the groups are defined to be relatively homogeneous no one's bill departs very much from the historical level. The big difference is that (with publicity) customers will know that it has become relatively inexpensive to increase off-peak usage, and that the rewards to conserving during the peak have grown. All responses to these changed incentives imply gains from the consumer (and provider) perspective.

The application of both equity rules can be illustrated in an example designed for transparency. Suppose we are designing rates for a moderate-sized utility with 500,000 residential customers, bills that average \$800 per year and average price per kwh of \$.10. Thus *TAR* in this example is \$400,000,000. Suppose further that under proposed marginal-cost based TOU rates that *MCR* is estimated at \$320,000,000 (the weighted average cost of peak and offpeak electricity is \$.08, as it would be if 20% of consumption occurred during peak hours with marginal cost of \$.20 per kwh and the other 80% of consumption was offpeak at marginal cost of \$.05 per kwh). That leaves \$80,000,000 to be raised in fixed costs.

If one simply divided the fixed costs evenly among the 500,000 customers, then *FC* would be \$160 per customer per year. However, those customers whose average bills had been only \$200 per year under the old system (1600 kwh offpeak and 400 peak) would not consider this very fair, as their new bill would be \$320. Those whose bills had been \$1400 per year (11,200 kwh offpeak and 3800 peak) would think the new system a bargain, as their new bills would fall to \$1280. Despite the efficiency advantage—those new electric-powered vehicles look much more attractive under this system—it is understandable that some consumer groups would oppose any such proposal as causing inequitable and undeserved bill shock to those least able to afford it (to the extent that low-consumption is concentrated among vulnerable populations).

To keep this illustration as transparent as possible, imagine that the residential customers cluster into three equal-sized groups that have the average bills (and consumption levels) already mentioned: a low-consuming group (*L*) with annual bills averaging \$200, a middle group (*M*) with average bills of \$800, and a high-consuming group (*H*) with bills averaging \$1400. The sum of the three fixed charges weighted by group size must equal the average fixed charge of \$160 per year necessary to raise \$80,000,000, shown in equation (5)

$$\$160 = (F_L/3) + (F_M/3) + (F_H/3) \qquad (5)$$

Suppose we use the proportional rule from equation (3) to set the three fixed charges F_L, F_M and F_H. Then since average consumption in the middle group is 4 times higher than the low group:

$$F_M = 4{*}F_L \qquad (6a)$$

and similarly average consumption in the high group is 7 times greater than the low group:

$$F_H = 7{*}F_L \qquad (6b)$$

Using equations (6a) and (6b) to substitute for F_M and F_H in equation (5), we have one unknown F_L and can solve:

$$\$160 = (F_L/3) + (4{*}F_L/3) + (7{*}F_L/3) = 4{*}F_L \qquad (5')$$

and

$$F_L = \$40,\ F_M = \$160 \text{ and } F_H = \$280.$$

In this example, the average bill within each group remains exactly the same as it was under the old system: \$200 for the low group, \$800 for the medium group, and \$1400 for the high group. Within a group, it remains true that those above the group average will be better off than before, and those below the group average will be worse off if their consumption remains unchanged. But we have greatly reduced the magnitude of windfall gains and losses ("bill shock") compared to a uniform fixed fee (consumers in the low and high groups are closer to their respective group averages than they were to the entire population average, the middle group is unaffected). We have increased the number of customers who will find that they are on balance better off by taking advantage of the efficiency gains of marginal cost prices (the gains from purchasing the electric vehicle and recharging at the low offpeak prices will more than compensate for modest losses if consumption were unchanged). We have achieved a better distribution of gains: more than half of *each* group, including the low-usage or "vulnerable" group, achieves these net gains.

In the example so far, all consumers were assumed originally to be paying the same \$.10 per kwh average price. But many electricity distributors utilize tiered pricing systems. In most cases of these, the price per kwh rises from one tier to the next. But there are also jurisdictions in which the opposite is true: price per kwh declines as consumption increases to reach another tier.[41] Suppose our jurisdiction had increasing tier prices, such that the average original bills in the three groups respectively from low to high were \$160, \$800, and \$1440 (chosen to keep TAR the same). Then the proportional rule that we used above to calculate the fixed charges per group as part of our new TOU system would no longer keep average bills in each group the same as in the original system.

Some might argue for the proportional rule anyway, simply as a matter of fairness. Other might prefer a more or less progressive approach, similar to views about the desired degree of progressiveness of a tax system. But then one might reason that the collectivity has already spoken on this issue, and its choice is already reflected in the design of existing tiered rates. That is the case for using the status quo equity rule of equation (4). Under this latter assumption, we assign the group fixed rates to keep each group's contributed revenue unchanged from the status quo. In this case, $F_L = 0$ since $TAR_L/n_L = 160$ and, for the low group's average consumption of 2000 kwh, $MCR(2000) = \$160$ (and the fixed assessment could be negative, or a credit, if equity preferences for this group were stronger). The average consumption in the middle group is 8000 kwh and $MCR(8000) = \$640$. Since $TAR_M/n_M = \$800$, then $F_M = \$160$. Finally, the higher-consumption group has $TAR_H/n_H = \$1440$ and it uses 14,000 kwh with $MCR(14{,}000) = \$1120$. Thus $F_H = \$320$ keeps its average bill as before. This second example illustrates that the fixed fees can be assigned to groups in a way that maintains the distributional equity of the status quo. Furthermore, it retains the same desirable features as the first: compared to a uniform fixed fee, we have greatly reduced windfall gains or losses, and we have ensured that a large proportion of the consuming population will receive actual net gains through efficiency improvements, and we have spread these gains so that low, medium and high usage groups all receive them.

A fuller exposition of this method is beyond the scope of this article, but it would allow treatment of several important complexities: the definition of peak and offpeak hours, the exact definitions of groups for residential populations, variation by group in the peak-intensiveness of its usage, reclassification of groups over time, and better measurement of gains and losses among the residential population. However it should be clear that good TOU rate design offers the prospects of making almost everyone, including vulnerable populations, better off.

3.3.2 Nudge or Shove to TOU.

Suppose now that we do have a TOU rate design with appropriate, relatively low off-peak rates. When this is simply made available to the consumer that can choose to opt in to it, we have strong evidence that most consumers do not opt in even when they would be made better off by doing so. This is referred to as the “status quo” bias in the behavioral economics literature. The proof of this powerful effect has been shown by reversing the status quo, and then observing that almost everyone sticks with the new status quo rather than opting in to their former choice. For any consumer choosing rationally, it should not matter which choice is the default. But the default matters a great deal.

One clear example reported by Benartzi and Thaler (2007) is of retirement plans at some firms in the United Kingdom that require no employee contributions at all; it is all paid for by the employer and thus free money. However, the employees had to opt-in to join it, and at 25 such firms studied only 51% of eligible employees signed up. Nor is this the only example. In another study, Choi, Laibson and Madrian (2005) identify a group of older employees that could make retirement contributions matched by their employer and that could be withdrawn immediately with no penalty—again, free money. However, 40% of this group either did not join at all or contributed less than the maximum.

If you think that perhaps people have real reasons why they are making the choices, then presumably the choices would not be affected by reversing the default position. However, numerous studies have shown that this is not the case. Madrian and Shea (2001) found that 65 percent of eligible employees in a large U.S. corporation were participating in the 401k program under the usual opt-in method after 36 months of employment, but this figure for the same time frame rose to 98 percent when the company switched to automatic enrollment unless the employee opted out. This same phenomenon seems to apply to many important choices. Daniel Goldstein (2009) gives the startling example of people deciding whether or not to donate their organs. In Germany, where people must explicitly choose to become organ donors, only 12% do so. But right across the border in Austria, where the default is to be in the organ donor pool unless a person has chosen to opt out, 99.98% of people stay in the pool.

There is scarce evidence on what difference it would make to (a) offer residential TOU as a voluntary opt-in program; (b) make residential TOU the default rate structure unless a consumer opts out and chooses another rate structure; or (c) make residential TOU mandatory. One interesting analysis was done of California's Statewide Pricing Pilot that tested a version of TOU called critical peak pricing. The customers reported high satisfaction with the program, and most indicated that they would remain on it if allowed. However, a presentation of the California Energy Commission reports estimates that only 10-15% of customers would choose it if it requires opting in, whereas 60-75% would remain on it if it were the default.[42] This also seems consistent with evidence reported by Letzler (2006) that only 1.3% of Florida customers chose to opt-in to a very similar program that promised an average of $90 in savings per year.

Upon what basis should a policy analyst come to a recommendation about the choice from opt-in, default, or mandatory? By the traditional assumptions of fully rational consumer behavior in choosing from among legitimate alternatives, it is almost impossible to recommend mandatory residential TOU (perhaps if so few people would choose non-TOU, the administrative cost of accommodating them could be too high). Furthermore, the choice between the other two would be of no consequence, as rational consumers would simply switch to their preferred system. Yet in this case, the choice from the three is a critical one, and by far the worst option would be to maintain the status quo of opt-in. Between making

TOU be the default and making it mandatory, mandatory should be favored with one caveat—that the mandatory TOU rate design be required to meet well-specified standards that include marginal cost rates. Why?

There are two reasons for preferring residential TOU as the default over its status quo as opt-in. The first reason is that it is likely to make a big difference empirically in the number of residences on TOU rates. While there is scant direct evidence about this, the status quo bias has been shown to be huge in numerous other cases, and the scant evidence that we have from electricity is consistent with this. If consumers are rational, there is no harm from this (as they can opt out). But the second reason is that there should be a bias in favor of the more efficient system. For all of the reasons why a consensus of economists have concluded that TOU is more efficient than time-invariant rates, and with a consensus that the efficiency benefit has only been growing more substantial over time, the default of TOU must be evaluated more highly than the status quo time-invariant system. It is not just that more residences will end up on TOU, but that this will be an improvement for almost all of them.

One might wonder if retail competition in electricity might bring about increasing use of TOU rates among residential customers. We have only limited experience with retail competition in the United States, primarily in New England, Pennsylvania, and Texas. However, all of these situations are constrained by the same lack of appropriate metering that we have already noted. Perhaps one should expect competitive retailers to more quickly bring AMI meters to their customers. In Texas, the meters are not controlled by the retailers but are owned by a different, noncompetitive entity. In New England, well over 90% of residential customers have remained with their former utility. These utilities are required to provide a “standard offer” that is typically referred to as the “price to beat” for comparison with competitors; all of these standard offers are for time-invariant rates. Thus a corollary to the argument to this point for restructured states is both to increase deployment of AMI meters and at least to make the “standard offer” a TOU rate.

To continue, what about mandatory TOU as opposed to simply having TOU as the default? The crucial factor here is to remember that time-invariant rates involve unwarranted and unfair subsidies and penalties. There is simply no excuse for us to continue subsidizing very costly and environmentally challenging peak-load usage by charging a price that is below its marginal cost. Nor should we continue to penalize off-peak consumption by charging a price above its marginal cost when it gives us critical GHG-reducing substitution possibilities (as with vehicle electrification) and important environmental flexibility among sources.[43] We are causing social harm in every instance that we allow this, even if some people benefit from this inefficient system. It is the same argument that causes analysts to oppose the inefficient agricultural subsidies, despite the fact that rich farmers like them. The fact that both have persisted for some time is no reason to support either of them. Time-invariant rates are no longer a legitimate choice to offer, and they should be phased out.

4. Conclusions

This policy research examines whether the current practice of pricing off-peak electricity usage might create a serious obstacle to the substantial reduction by 2050 of GHG emissions necessary to combat global warming. The focus on the price of off-peak electricity is because of the huge potential it has for enabling a reduction of GHG emissions, as through vehicle electrification that substitutes for the petroleum-based gasoline and diesel fuels that currently propel our vehicles. In California for example, transportation is responsible for about 40% of total GHG emissions and vehicle emissions would be reduced by 60% if the same vehicles using existing technology were powered by average California electricity. Just how efficient it is to do this depends on many factors, not the least of which is the relative cost of off-peak electricity to conventional vehicle fuels. As long as each fuel is priced at its marginal cost (including the cost of any GHG emissions), users considering the alternatives are given appropriate signals to guide their emission-reducing decisions.

However, the research undertaken here shows that off-peak electricity is currently priced at multiples above its marginal cost. For the U.S. as a whole, the average residential consumer faces a price for off-peak electricity (currently about $.12/kwh) that is 331% above the marginal cost of that electricity (just under $.03/kwh). This residential consumer price is high because 99% of these consumers are on traditional, time-invariant rate structures that do not distinguish peak and off-peak periods. It is simply absurd to think that these consumers will have appropriate incentives to increase the extent to which they fuel their vehicles by electricity. Furthermore, the problem does not disappear if we assume that these consumers could easily switch to a TOU rate schedule. For those places that have them, the average TOU residential consumer faces an off-peak price of about $.075/kwh, still almost three times higher than the marginal cost.

The importance of reducing GHG emissions makes it imperative that we take policy actions to bring down the off-peak electricity rates that consumers face to appropriate marginal cost levels. However, there are numerous obstacles that must be overcome. One of the most serious obstacles is metering. Just under 9% of American residences have the AMI meters that are capable of measuring the time of consumption. There have been some modest policies to encourage the development of a smart grid and the deployment of AMI meters, but even with these FERC expects the deployment rate to reach no more than about 40% of residences by 2019. This is not satisfactory, especially as there are many more reasons for having these meters than the one focused upon here. Yet it is also true that because AMI technology is both relatively new and developing rapidly, one cannot simply rush orders for them. It has been taking the pioneers in their use, like California which has required them for all residences, 5-7 years from the time of the requirement to full implementation. This implementation time may decrease as this part of the industry matures, but we must set the wheels in motion now to increase the deployment rate. The most promising policy actions are ones that encourage or require those jurisdictions that have been lagging to achieve full AMI implementation by around 2020.

Even as we increase the deployment of AMI meters, there remain substantial barriers. TOU rate designs must be improved so that rates are based upon marginal costs, and residential consumers must face such rates. This paper illustrates two types of rate designs that enable such rates, allow for full recovery of appropriate costs, and minimize changes in the monthly bill amounts that consumers receive. One is the "baseline" method that makes the bill equal to the conventional amount if consumption remains at its historic baseline level for that month, but applies marginal-cost rates to any deviations from the baseline. The second is the "two-part tariff" that sets rates at marginal cost and assesses a fixed amount per month to make up any difference between the marginal-cost based revenue and the amount allowed for appropriate cost recovery. The novel feature of design that ensures widespread gains among the residential population, including those with relatively low usage, is that the fixed part of the two-part tariff rises depending upon which of 5-6 consumption groups the consumer falls within. This also allows for flexibility with respect to concern for fair distributional consequences.

Even with TOU rate designs like these, there remains the question of whether or not consumers will switch to utilize them. The evidence from behavioral economics demonstrates that consumers have a very substantial "status quo" bias, in opposition to conventional economic thinking that consumers will make the choice that is most appropriate for them in their own judgments. Were the latter the case, it would not matter which choice is the default choice and which other choices can be made by opting-in to them. But with many important examples like retirement savings choices and organ donation choices, the choices made are vastly different and remain that way depending upon which choice is designated as the default. The scant evidence about this available for the choice between TOU or time-invariant rate plans suggests that the default choice will be hugely important here as well. Because we have strong reasons to believe that TOU is more efficient and will make almost all consumers better off, it is better for it to be the default choice (including being the standard offer in restructured states).

However, there is the further consideration of whether or not TOU rates should be made mandatory for residential consumers, as Connecticut is requiring. Again, the conventional model of consumer behavior seems to oppose this: the fact that many consumers choose time-invariant rates reveals that they must think they are better off on such a schedule. While behavioral economics certainly provides considerable skepticism about this conclusion, another area of economic theory trumps it altogether and leads to the opposite conclusion that TOU rates should be made mandatory. Time-invariant rates are a historical anachronism, a system of grossly inefficient subsidies and penalties that no longer has a legitimate basis for continuation. It seems unconscionable for us to continue to subsidize peak-load consumption when its social costs are so great, and to penalize off-peak consumption when it holds so much promise as a method of environmental improvement. We need to phase time-invariant rates out, and to move to full deployment of equitable TOU marginal-cost based rates as quickly as we can.

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Endnotes

[1] The latter is also an important issue, but will not be the focus of this paper. Retail electricity prices should rise by the marginal cost of GHG allowances necessary to generate the electricity. However, most retail rates are set at average cost rather than marginal cost, and if electricity distribution companies effectively receive revenue to offset allowance costs (e.g. by free distribution of the allowances to them, or by earmarking some portion of auctioned allowance revenue to them), then even their average costs may not rise by the full value of the allowances.

[2] The reduction would not be as great for jurisdictions relying primarily upon coal-fired electricity, but it would still be significant. The 60% reduction figure is the average of two calculations using the approved "carbon intensities" and "energy economy ratio" for electricity of the California Air Resources Board as of February 2011. According to it, gasoline has a carbon intensity of 95.86 gCO_2e/MJ. Electricity has an energy economy ratio of 3, meaning one MJ of it will move a passenger vehicle 3 times the distance than if the MJ was generated by a gasoline engine. Average electricity including imports from out-of-state coal-fired plants had a carbon intensity in 2005 of 124.10 and thus if used to power vehicles would reduce emissions by 57% (= 100 * [95.86 – 124.10/3]/95.86). However, "marginal electricity" in California comes from natural gas and renewables that have a lower carbon intensity of 104.71 gCO_2e/MJ, and vehicles powered by these sources will reduce emissions by 63% (= 100 * [95.86 – 104.71/3]/95.86). See CARB (2009).

[3] Some who value the GHG reduction highly might use it anyway, for the same reasons that some people voluntarily provide support for other public goods.

[4] The survey we are referring to is the December 2010 Assessment of Demand Response & Advanced Metering by the Federal Energy Regulatory Commission. It reports fewer than 25,000 residential customers of more than 11 million served by the state's three investor-owned utilities as on any form of TOU rates. The California off-peak marginal cost is estimated by using the average off-peak price of $.028/kwh reported by the California Independent System Operator (CAISO) for April-June 2009.

[5] The California Energy Commission has a table on its website "Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State (EIA)" in which it is reported that California residential customers had an average rate of $.1464 per kwh in the year ending May 2009. Because most consumers use amounts beyond the first-tier (baseline) quantity, their marginal rates exceed their average rates.

[6] For example, customers of PG&E on the most common residential rate schedules (E-1, EM, ES, ESR, ET) have an average rate of $.17643, but those customers who are between 201-300% of the baseline quantity pay a marginal rate of $.37866 and those 300% above or more pay a marginal rate of $.44098. These rates are from the schedule on the PG&E website described as in effect from March 1, 2009 through September 30, 2009.

[7] The arguments for the more sophisticated variants of simple TOU pricing, like real-time pricing where rates could vary from minute to minute and day to day, were simply extensions of the same argument: efficiency requires that customers always face rates equal to marginal costs, and that marginal costs during all or part of unusual days (e.g. very hot summer days, very cold winter days, or days with unexpected major supply interruptions) could be many multiples of marginal costs at a similar hour during a more typical day.

[8] If the consumer has some excess on-site electricity like that from a solar system, the excess can be sold and delivered to the grid by having the meter run backwards. This is called net metering as the consumer only pays for the difference between its electricity taken from the grid and that supplied to the grid.

[9] See, for example, the very interesting recent review by Newsham and Bowker (2010).

[10] See Friedman (2009).

[11] One of the first proponents of this idea was Coase (1946).

[12] This is the simple average of the April, May and June off-peak LMPs in $/mwh shown in Table 3.3.4 as $31.48, $33.35, and $31.46.

[13] ISO New England states that its figures do not represent billing figures. Some of the non-LMP charges are monthly charges that it simply divides by the number of mwhs reported for that month in order to produce cost/mwh numbers. This procedure does not attempt to distinguish what costs are appropriately charged to peak or off-peak periods.

[14] The Energy Information Administration (1997) reported that all distribution expenses were 19 percent or $.013 of the $.071 full average cost of electricity (p. 11). Updating this from 1997 to 2008 by the Consumer Price Index yields an estimate of $.017.

[15] We also tried an alternate method for estimating off-peak marginal costs for the non-ISO states shown in column (2). This did not substantially change the results. We used 2009 data from the Intercontinental Exchange (ICE), calculating the simple average of peak and off-peak prices for 6 hubs having both available. Compared to the NERC data for the same six states, wholesale prices have declined by 1.935 cents/kwh from 2007. We used this number to adjust the 2007 NERC data to be estimated 2009 wholesale prices. Then we again calculated the ratio for ISO states of off-peak marginal costs to these estimated 2009 prices, which was 79.7%. We used this percentage to estimate off-peak marginal costs for the non-ISO states, and derived an overall average U.S. off-peak marginal cost of 2.844 cents/kwh.

[16] This understates the true rate (and thus the distance from marginal cost) that we calculate for the reason given previously for California: in many states an increasing tier system is used (although there are also decreasing ones), and for these the average is less than the marginal rate.

[17] 12.05 cents per kwh is the simple average of the rates given for each of the states. The average weighted by each state's kwhs is almost the same, 11.91 cents per kwh (only 1% difference). The weights necessary to compute weighted averages are not always available for our calculations.

[18] The 2010 FERC survey, released in early 2011 and discussed in the next section, was not yet available when we chose our sample utilities.

[19] The 7 states are Louisiana, Mississippi, Nebraska, North Dakota, Rhode Island, Utah, and Washington.

[20] Five utilities in the subsample had block TOU rates (decreasing in Iowa, Oklahoma, Pennsylvania and Wyoming, increasing in Oregon), and in those cases we report the second block which represented consumption in the 600-800 kwh monthly range for residences.

[21] For purposes of the survey, FERC defines advanced meters as ones "…that measure and record usage data [and possibly other parameters] at hourly intervals or more frequently and provide usage data to both consumers and energy companies at least once daily." See p. 6 of FERC(2011). FERC changed the definition slightly in 2010 from that used in earlier surveys to include the requirement that the meters provide daily usage data to customers.

[22] Almost all households are still metered by the older electromechanical meters that do not measure when electricity is consumed. Some households are metered by "automated meter reading" (AMR) meters that preceded the age of smart meters and offered some limited advances that do not necessarily include time of day capability. Some AMR meters, for example, are read by having the meter reader wave an electronic wand near them, which increases accuracy and speeds up the time it takes to read the meters.

[23] EPRI (2007).

[24] FERC recognized that there are instances of double-counting of the same TOU programs, particularly when there is one entity that provides distribution service and a separate entity that provides transmission and generation services. FERC examined the data for this and made corrections in terms of the TOU programs, but it is possible that some double-counting errors remain.

[25] See FERC (2009b), p. 11.

[26]Southern Company received $164 million, Duke $200 million, and Pepco $200 million, along with 10 other electricity companies that each received in excess of $100 million.

[27] PG&E's original 2006 order approved its plan to retrofit 54% of its existing electric meters and 96.1% of its existing gas meters (p. 3, CPUC Decision A.07-12-009 dated 3/12/2009). But at the end of 2007, it filed a request to upgrade its program in order to use all new solid-state meters (allowing remote upgrades to firmware and software) rather than the retrofits as well as to include a load-limiting connect/disconnect switch and a Home Area Network (HAN) gateway device to support in-home HAN applications. This was approved but not until March 2009.

[28] See the independent assessment by Structure Consulting Group LLC ordered by the CPUC and completed Sept. 2, 2010 at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/solicit.htm. Public wariness is voiced in the press, as in David R. Baker, "Customers Say New PG&E Meters not always Smart," San Francisco Chronicle, October 18, 2009 at http://www.sfchronicle.us/cgi-bin/article.cgi?f=/c/a/2009/10/18/BUJI1A658S.DTL&type=printable.

[29] SDG&E received authorization to proceed with its AMI deployment on April 12, 2007 (CPUC D.07-04-043). SCE received similar authorization on September 22, 2008 (CPUC D.08-09-039). The SDG&E authorization followed pre-deployment activities first approved in August 2005 for the rest of 2005 and 2006. The planning paid off for SDG&E as it was awarded a $28 million ARRA grant to share the $60 million cost of its planned system. The SCE authorization followed the completion of two earlier phases, in which the first phase that began in December 2005 was simply to study the availability of an AMI that had the features desired by SCE and the CPUC, and a Phase 2 in July 2007 that began field testing of several specific types of AMI meters.

[30] See note 8 for a definition of net metering. It is worth mentioning that some analysts think there is potential to use electric vehicles as large batteries that draw electricity in the least-expensive off-peak times and sell it back to the grid during the more expensive peak hours; this would be an unintended consequence of Connecticut's legislation, as this use was not envisioned as part of the motivation for it.

[31] This cost substantially exceeds the average installation costs of $200-225 for AMI metering generally reported elsewhere, as in EPRI(2007) and FERC(2006).

[32] See FERC (2009a), Table A-1, p. 80.

[33] See Texas PUC (2008), pp. 2-3.

[34] See Pennsylvania PUC "Implementation Order" re Smart Meter Procurement and Installation, Docket No. M-2009-2092655, June 18, 2009.

[35] See p. 19 of Pennsylvania PUC "Initial Decision" re Approval of Smart Meter Technology Procurement and Installation Plan, joint petition of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company, Docket No. M-2009-2123950, January 28, 2010.

[36] FERC (2009b) also identifies Hawaii, Kentucky, Massachusetts, Ohio and Vermont as having adopted plans or legislation that includes both the deployment of AMI meters and the use of dynamic pricing.

[37] It should be noted that this section, in referencing the number of AMI meters, assumes each AMI meter is taking the place of what would otherwise be an older-style meter. Some people have suggested that an electric vehicles should have its own AMI meter with special vehicle rates in addition to a household's meter for all other electricity services. This seems like a needless expense and is in opposition to basic economic principles: the price of electricity should be the marginal cost of providing it, and it should not depend on the particular use to which the electricity is being put. As long as the rates are the same regardless of usage, then it is strictly a technological question if the cost of any extra equipment that facilitates a service like vehicle charging (e.g. if a consumer prefers a faster-charging 220 volt line as is used for some appliances to an ordinary 110 volt line) might actually be lower by including its own meter. There may be some atypical cases for which this is true (e.g. a detached garage with no current electrical service and far from the resident's existing meter). The point here is simply that the argument in this section for expanded AMI deployment is referring only to metering upgrades, not to additional metering.

[38] Baldwin and Childs (1969) were the first to point out that in some circumstances it can be more efficient to imitate quickly (the fast second) rather than undergo all the development costs necessary to be first. In this case we have barely any competition at the retail level that might force AMI adoption after some initial deployments, but it can nevertheless be true that the most efficient adoption pattern is with most jurisdictions acting as fast seconds.

[39]The marginal cost calculation should include the marginal cost of capacity, although most of this occurs during the peak-period hours and it is often calculated independently of customer total kwhs. Technically the capacities of an electricity system are joint costs—costs that are incurred once but used to produce and carry different services, in this case electricity at different time periods. Thus the marginal cost of capacity is shared by the different services—peak and off-peak electricity—provided with it. It can be a difficult technical problem to determine the proper capacity charges assigned to each of the services produced with the available capacities. See Wenders (1976) for an exposition. However, two factors work to minimize the share that should be assigned to off-peak service: the geographic broadening of the relevant market for transmission and generation, and the large demand differences for peak and off-peak electricity.

As our generation markets become geographically broader and more competitive, there is less need for new small peaking plants as other plants (and growing demand response programs) serving a larger area can fulfill peak demands at a lower cost. Competitive systems in effect now, like ISO-New England and PJM, determine capacity additions and competitive capacity charges purely as a function of peak-period demands. Additionally, because the demand for electricity is so much less during off-peak hours than it is during peak hours, and because the respective demands are highly inelastic, the appropriate share of capacity costs for off-peak hours is small. For example, peak demand in ISO New England during the first (winter) quarter has been between 21,000-22,000 MW in 2007-09 whereas the median load has been at 16,000 MW, and the off-peak load goes down to about 10,000 MW at the minimum (See p. 8 Figure 3 of ISO New England 2009 First Quarter Markets Report). Off-peak consumers should not be charged for the cost of intermediate-level and peaking plants that they do not use, nor extra transmission lines that they do not need. Off-peak users should pay some portion of the marginal cost of baseload capacity, but this marginal cost may be small if it is accompanied by a reduction in the need for intermediate and peaking capacities. Should there be a large increase in off-peak usage relative to the peak, perhaps because of a strong growth in off-peak charging of electric vehicles, then the share of capacity attributed to “off-peak” usage could increase (or equivalently, the number of hours considered off-peak could decrease).

[40] Equation (4) summed across *i* gives this expression:

$$\sum_i n_i FC_i + \sum_i n_i MCR(\bar{Q}_i) = \sum_i TAR_i$$

The second term in this expression is simply MCR, and the third term by definition is TAR. So we have:

$$\sum_i n_i FC_i = TAR - MCR$$

First decomposing the left-hand side and then rearranging terms and dividing by n_i gives equation (2):

$$n_i FC_i + \sum_{j \neq i} n_j FC_j = TAR - MCR$$

$$FC_i = (TAR - MCR - (\textstyle\sum_{j \neq i} n_j FC_j))/n_i$$

[41] California is an example of a state with increasing tier rates, and Iowa is an example of a state with decreasing tier rates (e.g Interstate Power and Light, Original Tariff No. 1). Tiered rates are also referred to as block rates.

[42] See presentation by Mike Messenger on the California Energy Commission website dated April 24, 2006 at http://www.energy.ca.gov/energy_action_plan/meetings/2006-04-24_meeting/presentations/2006-04-24_MESSENGER_INCREASE_DR.PDF.

[43] One excuse is legal. For example, New York state law prohibits mandatory or even default TOU rates for residential customers (FERC 2006, p. 131, referencing NY Public Service law 66(27)). This is clearly another type of barrier, even if one argues that this law should be repealed. One important factor that motivates this type of barrier as well as other forms of resistance are poor rate designs, especially those that do not consider adequately the exposure to peak rates of certain vulnerable groups, like the elderly or lower-income families in apartment units without individual meters. There are numerous ways to institute marginal-cost based rates that have only minimal bill changes at current consumption levels.