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Residential Electricity Prices: A Review of Data Sources and Estimation Methods *

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Abstract

This paper presents an empirical study of residential electricity prices based on a compilation of tariff data collected for Lawrence Berkeley Lab's Tariff Analysis Project (TAP). We also review other data sources commonly used to estimate residential sector electricity prices, including utility data published by the Energy Information Administration (EIA), the *Typical Bills* reports published by the Edison Electric Institute, and household-level electricity consumption and expenditure data included with the EIA's Residential Energy Consumption Surveys. We define three different types of price that can be estimated from the data, construct estimation methods, compare the results and evaluate the relative strengths and weaknesses of each approach. We examine several sources of variation including seasonal, regional, industry structure, and the magnitude of baseline household consumption. The tariff data are also used to explore the impact of moving households from standard tariffs to time-of-use pricing, and to summarize how this affects predictions of electricity bill savings for both demand reduction and demand shifting.

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1 Introduction

Consumer-oriented analyses of the economic impacts of electricity demand management strategies are based on a comparison between the costs of the measure and any potential economic benefits to the consumer. For example, life-cycle cost (LCC) analyses are frequently used to evaluate the potential net consumer benefit of investments in energy-saving equipment. The LCC is equal to the sum of the equipment purchase and installation costs and the net present value of the lifetime equipment operating costs. In evaluating different equipment choices, the cost of a more energy-efficient but more expensive design may be offset by the benefit of reduced operating costs, with the latter primarily determined by the value of energy savings. This type of analysis forms the basis of tools such as the *Home Energy Saver* [9], and policy impact studies such as the Department of Energy's (DOE) Appliance and Equipment Standards rule-making analyses [3]. In the simplest approach, electricity cost savings are estimated using a single price for electricity that is multiplied by the change in kilowatt hours (kWh) consumed. In reality the pricing schemes used by utilities and encoded in their tariff documents can be considerably more complicated, and reflect the fact that provision of electricity is a service, and that the supply of the commodity kWh is only one aspect of that service. With the availability of smart meters and appliance controls, energy management strategies are themselves evolving to incorporate shifts in the timing and pattern of electricity use across a range of time scales on the demand side as well. Under these conditions it seems clear that the value of electricity cannot necessarily be captured by a simple commodity price.

In an effort to better understand utility pricing and the marginal value of reductions or shifts in electricity use, Lawrence Berkeley National Laboratory (LBNL) began compiling a database of electricity tariffs in 2005 [1, 2], known as the Tariff Analysis Project or TAP. This paper presents both a review of the TAP data for the residential sector and, more broadly a comparison and evaluation of the other available data sources.[1] The goals of this study are to:

- provide precise definitions of different price concepts, and of their applicability in different analysis contexts;
- quantify the degree of variability in prices due to baseline energy use and the pattern of changes to energy use on the customer side, and due to region, season, and industry structure on the utility side;
- define price estimation methods appropriate to different datasets;
- compare results from different calculation methods and/or datasets, and provide recommendations for use in practice.

While the TAP data provide a great deal of information about electricity tariffs for the selected utilities, all the data sources we review here are needed to assemble a complete picture of the industry. The additional datasets we review and analyze are:

[1]A similar study covering the non-residential sector is in preparation.

- the Energy Information Administration (EIA) Form 861 annual [6] and monthly [7] which provide data on revenues, sales and consumer counts by sector for all utilities with sales to final consumers;[2]
- the EIA Residential Energy Consumption surveys (RECS) for 2009 [12], particularly utility billing information on monthly expenditures and consumption;
- the Edison Electric Institute *Typical Bills and Average Rates* biannual reports [5], which provide the total utility bills at specific consumption levels for a large selection of investor-owned utilities.

These data differ in frequency of collection, coverage of utilities, and the level of detail in the description of the consumer population. The characteristics of different datasets are summarized in Figure 1. It is not the aim of this paper to reproduce the types of price estimates and historical trends that are published by the EIA; instead our goal is to use the comprehensive EIA data to evaluate sampling and other potential biases in the more limited datasets, and to use the latter to develop price estimates that cannot be made from the EIA data.

		Data Set				
		EIA861	EIA861m	EEI Typical Bills	RECS Billing	TAP
Ownership Type	Public	x	x			x
	Private	x	x	x		x
Price Type	Utility Average	x	x			x
	Utility Commodity		x			x
	Household Average			x	x	x
	Household Commodity			x	x	x
	Household Marginal					x
Price Period	Annual	x	x	x	x	x
	Seasonal		x	x	x	x
Household Data	Typical kWh			x		x
	Actual kWh				x	x
Time Frequency	of Publication	annual	annual	6 months	few years	few years
	of Data	annual	monthly	billing period	billing period	billing period

Figure 1: List of datasets that have been reviewed for this analysis.

The rest of this paper is organized as follows: In Section 2 we present definitions of different price concepts at the household level, and discuss the level of aggregation intrinsic to different datasets and how it affects price estimations. We provide an overview of the utility industry structure and discuss how it affects retail prices, and define the averaging methods used to construct state and regional price estimates. In Section 3 we present and compare price estimates calculated from the EIA, EEI, RECS and TAP data, and discuss

[2]EIA Form 861m was previously known as Form 826.

how the prices vary with baseline household electricity use. In section 4 we use the TAP data to review time-of-use rates and calculate an effective price per kWh that applies when electricity use is shifted from on-peak to off-peak periods. In Section 5 we summarize our findings and present our recommendations for consumer-focused analyses.

2 Price Concepts and Data Overview

2.1 Price concepts

For a simple commodity the price is the amount you pay per unit consumed. For a service such as electricity covered by a complex tariff there may be a variety of prices listed for different service components; what the customer really sees is a bill. Given the bill data a number of prices can be defined. Conceptually the bill b is a function or algorithm, which takes as input the household electricity use e during the billing period. The tariff itself is the specification of how b depends on e; here we represent the tariff as a function f that defines

$$b = f(e). \tag{1}$$

While the bill is a continuous function of electricity use, in most applications we work with discrete data, so that approach will be adopted in this analysis. The energy consumption depends on household characteristics and weather, and the bill depends on the input e and the structure and data of the utility tariff. To capture these dependencies our notation is:

- the tariff index is i,
- the household index is j,
- the billing period index is k; for simplicity we assume billing periods are calendar months (so k is also a month index),
- the electricity use for household j during period k is e_{jk},
- the utility bill under tariff i is b_{ijk},

We define the average price p_{ijk} as the ratio of the total bill to the energy consumption,

$$p_{ijk} = \frac{b_{ijk}}{e_{jk}}. \tag{2}$$

The marginal price is the incremental change in the bill given an incremental change in consumption, which we define as

$$m_{ijk} = \frac{\Delta b_{ijk}}{\Delta e_{jk}}, \tag{3}$$

where the Δ represents a small change of either sign.

kWh	Bill $	Average Price $/kWh	Marginal Price $/kWh	Commodity Price $/kWh
400	50	0.125	0.100	0.100
800	105	0.131	0.150	0.119
1500	235	0.157	0.200	0.150
3000	585	0.195	0.250	0.192

Table 1: Example of prices calculated for the tariff shown in Figure 2 assuming a fixed charge of $10.

We define the commodity price for electricity as follows: most tariffs include a fixed charge f_{ik} which does not depend on consumption but may depend on the billing month. If we remove the fixed charge from the bill, and take the ratio of the remainder to the electricity use, we get the average price per kWh for the consumption-dependent piece of the bill:

$$c_{ijk} = \frac{b_{ijk} - f_{ik}}{e_{jk}}. \tag{4}$$

Because the bill is a function of the input electricity use, the prices are also functions of this variable. The behavior of the bill/prices as a function of e depends on the details of the tariff. Most residential non-time-of-use tariffs consist of block rates, *i.e.* a constant price for electricity within certain consumption bounds as illustrated in Figure 2. This figure shows a case with four tiers. The marginal price at a given consumption level is the rate shown in this figure. The average price depends on the individual block rates and the size of the fixed charge. For a fixed charge of $10 per month, the bill and prices at different levels of consumption are shown in Table 1. This example illustrates that the commodity price is always less than the average price, but the true marginal price may be greater or less depending on both the details of the tariff and the household baseline electricity use. Note that most analysts do not distinguish between the marginal price and the commodity price, and refer to any estimate of the incremental cost of the next kWh as a marginal price. We make this distinction in Table 1 where we refer to the utility and household level prices derived from EIA and RECS as commodity and those from TAP as true marginal. The EEI data are somewhat indeterminate, but as discussed further in the next section seem to reflect true marginal prices. While for residential tariffs the difference between commodity and marginal price is numerically small, at the regional level it is systematic and may therefore lead to a small bias in valuation.

2.2 Data Overview

2.2.1 EIA 861 data

The EIA Forms 861 [6] and 861m [7] provide revenues, sales in megawatt hours and consumer counts to each sector (residential, commercial, industrial) organized by utility and by state. Form 861 provides annual data for all utilities who retail to final consumers, and Form 861m provides monthly data for a smaller sample consisting primarily of larger

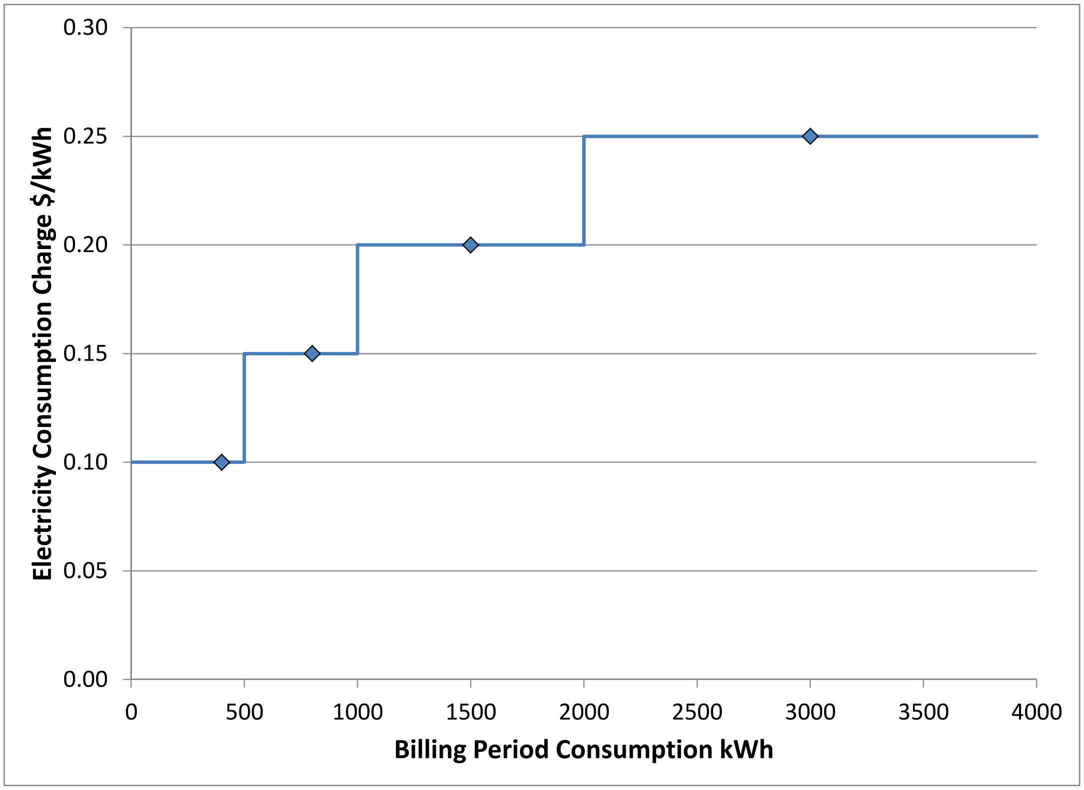

Figure 2: Example of a tariff with ascending block rates or tiers. The plot shows the rate charged for consumption as a function of electricity use. The diamonds indicate the kWh values for which prices are calculated in Table 1.

utility companies. The data are aggregated over all customers within a given sector, and hence all tariffs that apply to that sector.

The EIA data can be used to generate a utility-level retail price for each sector by dividing the total revenues by the total sales. For a given utility u the total residential sector revenues can be written as:

$$R_u = \Sigma_i \Sigma_j \Sigma_k \, b_{ijk}, \tag{5}$$

and total sales as

$$E_u = \Sigma_i \Sigma_j \Sigma_k e_{jk}. \tag{6}$$

The price estimate based on these data is the ratio of the two. Using the definition of average price in equation 2 we can write the utility-level price for utility u as

$$P_u = \frac{R_u}{E_u} = \frac{\Sigma_{ijk} e_{jk} p_{ijk}}{\Sigma_{ijk} e_{jk}}. \tag{7}$$

Code	Region Name	States	Short Name
1	New England	CT, MA, ME, NH, RI, VT	NE
2	Middle Atlantic	NJ, PA	MATL*
3	East North Central	IL, IN, I, OH, WI	ENC
4	West North Central	IA, KS, MN, MO, ND, NE, SD	WNC
5	South Atlantic	DC, DE, GA, MD, NC, SC, VA, WV	SATL*
6	East South Central	AL, KY, MS, TN	ESC
7	West South Central	AR, LA, OK	WSC*
8	Mountain	AZ, CO, ID, MT, NM, NV, UT, WY	MTN
9	Pacific	AK, HI, OR, WA	PAC*
10	New York	NY	NY
11	Florida	FL	FL
12	New York	TX	TX
13	California	CA	CA
14	United States	All	USA

Table 2: Region definitions used for regional averaging. The * indicates a census division from which a large state has been removed.

This formula shows that P_u is a consumption-weighted average of p_{ijk} over all the utility's residential customer bills for a year.

For consumer-focused analyses it is more appropriate to use consumer counts to weight any disaggregated data, so that the average represents the typical price charged to a consumer. Here we construct state-level, and regional prices by weighting the utility-level price with the utility consumer counts from the EIA 861 database. At the state-level the average price is denoted P_{ST} with

$$P_{ST} = \frac{\Sigma_{u \in \mathrm{ST}} N_u P_u}{\Sigma_{u \in \mathrm{ST}} N_u}, \tag{8}$$

where N_u is the number of residential consumers for utility u in state ST. Similarly, we define regional average prices P_R by taking the sum over all utilities in region R. In this paper we generally use *census division - large state* as our regional breakdown, with the large states being California, Florida, Texas, and New York. This convention is consistent with that used in most of the RECS surveys [12]. Table 2 defines the state assignment and the codes used in the charts and tables. In cases where the data are not sufficient to break out the large states we use census divisions as regions.

The EIA 861m monthly data can, in principle, be used to evaluate both seasonal price differences and the utility-level incremental revenue per unit of sales, which is an analogue of the marginal price. The latter is estimated by performing a regression analysis of the monthly revenues R_{uk} and sales E_{uk} for utility u and month k. This analysis can also be done for the summer and winter seasons separately. Here we define summer as May through September; to provide a continuous series of months for winter we define the winter season as October through December of year $y-1$ plus January through April of year y. To reduce noise in the data we use a robust method, the Theil-Sen estimator [11], rather than ordinary least squares. The Theil-Sen estimator is the median slope of the set of lines passing through all data pairs in the sample. This method provides seasonal and annual utility-level marginal price estimates. These prices are then aggregated to the regional level using the approach of equation 8; we use census divisions here to further reduce the noise in the data. The results of this analysis are summarized in Figure 3. The

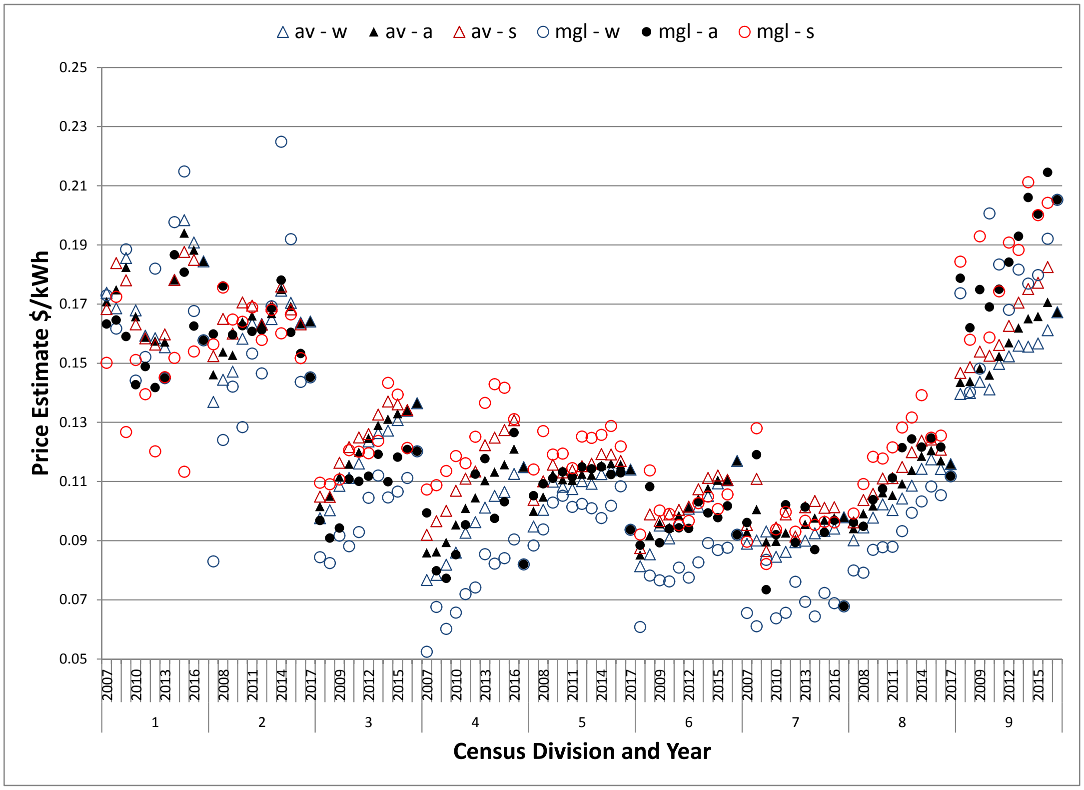

Figure 3: Price estimates by region and year for EIA 861 monthly. In the legend the letters (a, w, s) refer to annual, summer and winter respectively, and (av, mgl) to average or marginal price estimators. Summer data have open red markers, winter open blue and annual filled black.

plot illustrates the difficulty with this dataset. For census divisions 3 though 8 there is a reasonable pattern, with summer prices generally higher than annual, and winter lower than annual. These data generally show marginal prices to be lower than average prices in winter and higher than average prices in summer. For regions 1, 2 and 9 however there is no discernible pattern in marginal prices, annual or seasonal. The volatility can be smoothed out by doing the regression on data aggregated to the state level, however this approach also smoothes out most of the variation, with the results showing little difference between average *vs.* marginal or seasonal *vs.* annual prices. No other dataset shows this level of volatility in year-to-year changes of average or marginal price. We conclude that the EIA 861 monthly dataset is not able to provide reliable estimates of marginal prices.

2.2.2 Edison Electric Institute Typical Bills

The Edison Electric Institute (EEI) publishes a *Typical Bills and Average Rates* report for summer and winter each year [5]. The data in these reports consist of the total consumer bill at fixed consumption levels of 500 kWh, 750 kWh and 1000 kWh for approximately 200 utilities, all of which are investor-owned. For the EEI data we estimate average and marginal prices as in equations 2 and 3, with the understanding that for EEI the index i refers to a utility (no tariff is specified), j to a season (summer or winter), and k to one of the three consumption levels. We have found that in general there is little variation in prices across these three consumption levels; for many utilities the calculated marginal price is identical across one of both tiers. The close spacing of consumption levels in the EEI data suggest that they sit in the same or consecutive tiers as to the example of Figure 2, so the prices we calculate are true marginal prices. As shown in the next section 1000 kWh is most representative of actual monthly household electricity use, so we use the average price for 1000 kWh, and the marginal price based on the difference between the 750 kWh and 1000 kWh bills, to represent the EEI data.

2.2.3 RECS

The EIA conducts the Residential Energy Consumption Survey (RECS) about every five years, including the collection of utility bill data on electricity use (kWh) and expenditures (bills) [12]. The RECS sample consists of several thousand individual households, stratified by region and housing unit type, each assigned a weight that represents the number of comparable households in that region. In this study we use the data from RECS 2009 as a source of information on both electricity prices and electricity consumption in households [12]. The reported RECS billing periods are converted to typical months by dividing the kWh or bill by the number of days in the billing period, and normalizing to 30.5 days for a typical month. The data are filtered to remove outliers which arise primarily due to unusually long or short billing periods. The monthly consumption data are summarized in Figure 4. The monthly kWh from the RECS bills are assigned to bins of 0-500, 500-1000, 1000-2000, *etc.* ; for each region, the total weight in each bin is defined as the sum over the product of the RECS household weight times the number of bills for that household that fall into that bin. The RECS data show that 37% of household bills are for 1000 kWh or less, another 38% are in the range of 1000-2000 kWh, and only 1.6% are for more than 4000 kWh. The average monthly consumption ranges between 1200 and 1800 kWh per month, depending on the region and housing unit type. The RECS monthly bill data are used to estimate seasonal and annual average prices as the ratio of bill to consumption, and marginal prices using ordinary least squares regression. As for the EIA 861 monthly data summer is defined as May through September and winter the rest of the year. For the RECS-based estimates, the utility and tariff are unknown. Regional averages are calculated by weighting the household-level prices with the RECS sample weight.

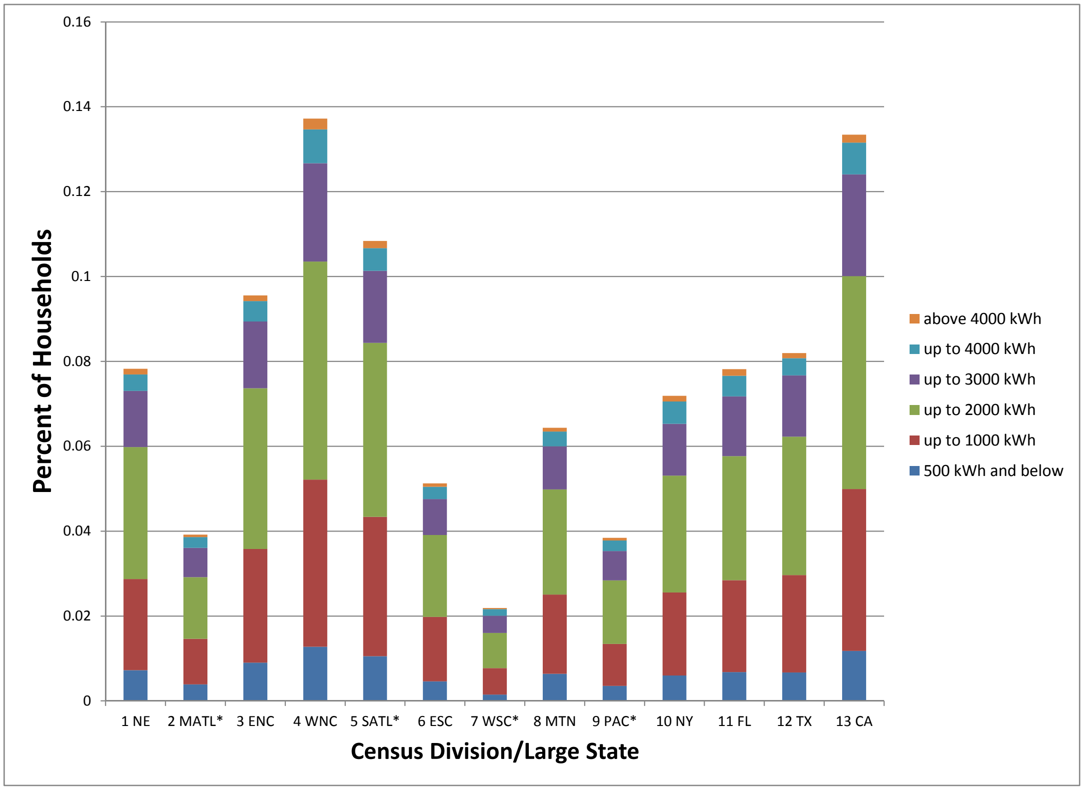

Figure 4: Distribution of monthly electricity use by region (horizontal axis) and consumption level (indexed by color).

2.2.4 TAP

The TAP database consists of a set of 2,229 tariffs collected for 150 utilities, covering both investor-owned and publicly-owned companies, for three data years. Of these 654 are residential and 1575 are non-residential. The sample is designed to provide good coverage of the industry at the level of census division - large state. The information in the tariffs is stored in a set of normalized data tables that can accommodate most of the features (seasonal rates, time-of-use, block rates *etc.*) used in real tariffs [1]. For the residential sector we collect the default tariff for each utility and an optional time-of-use tariff if it is offered. The TAP database is the only electricity price dataset that allows the marginal value of changes in electricity demand and consumption to be calculated without approximation, and that can explicitly model time-of-use rate structures. Although the TAP database is not large, given the complexity of most tariffs it is difficult to expand and update the data.

TAP also incorporates tools that allow the bill b to be calculated from the tariff function f

given the electricity use e, and all relevant prices as defined in Section 2. For this analysis we calculate TAP bills for representative consumption levels of 1000, 2000, 3000 and 4000 kWh. We have also calculated bills for 5000 and 6000 kWh, but find that, for almost all tariffs, above 4000 kWh the estimated marginal price is not affected by further increasing the consumption. As noted above only 1.6% of the bills in RECS are for more than 4000 kWh, so this represents a reasonable upper bound on monthly electricity use.

2.3 Utility Industry Structure

Broadly speaking, the utility industry can be segregated into two types of provider and two types of service. The two types of provider are privately- and publicly-owned. The EIA 861 data assign each company an ownership type, with all investor-owned utilities (IOUs) and most power marketers privately owned, while the publicly-owned utility (POU) sector consists of cooperatives and municipal, county, state and federal agencies. The two types of service are bundled and unbundled. For bundled service both the supply and the delivery of energy are provided by the same company, in unbundled service they are provided by different companies. For customers taking unbundled service, there is no public data source describing how energy and delivery service providers are paired, so there is no way to determine the total bill at the household level. For this reason both the EEI and the TAP data cover bundled service only.

We use the EIA data to evaluate whether there are systematic differences in price based on provider and service type. As EIA tabulates each utility's data by state, at the state level the total sales and consumer counts for unbundled delivery service should equal the total sales and consumer counts for unbundled energy (EIA includes an adjustment to enforce this identity). We use these data to define a single *unbundled utility* for each state. The revenues to this unbundled utility are equal to the sum of revenues for energy and delivery, and an average price is defined as in equation 2. We define average prices at the state level for each ownership category by including only IOUs or POUs in the sum of equation 8.

The comparison of bundled and unbundled service is summarized in Figure 5 and Table 3. The figure shows time series of total residential customer counts for public and private companies, with the unbundled segment shown in red. The vast majority of unbundled customers are with private companies, typically with energy provided by retail power marketers and delivery by utility companies. Unbundled market share grew from 1% of consumers in 2006 to a peak of 9% in 2014 and is at 7.7% in the most recent 2016 data. Table 3 shows, for those states with unbundled service, a comparison of the state-level average P_{ST} for bundled *vs.* unbundled service (public and private combined). The last column in the table shows the percent of consumers in that state taking unbundled service (values less than 0.05% show as zero). To smooth out some of the inter-annual variability, the data for 2014-2016 are averaged in this table. In general, the price estimate for unbundled service is somewhat higher than for bundled service; at the national level the difference is 0.147 *vs.* 0.119 $/kWh, or about 20%. The table shows that the price discrepancy tends to be larger when the market share is smaller, and vice versa. In further analysis of the EIA data, we find that excluding the unbundled utility from regional

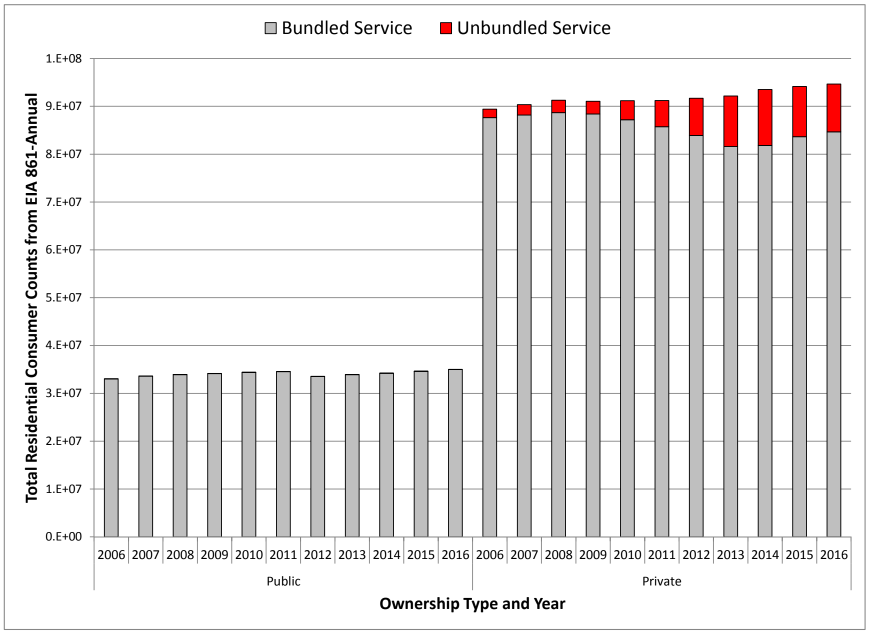

Figure 5: Residential customer counts from EIA Form 861 for the POU and IOU sectors with number of unbundled customers shown in red.

averages does not have a significant impact on the results. Hence, for the rest of this paper we include the unbundled utility data in the EIA averages, but do not correct for the fact that this market segment is not explicitly sampled in the other datasets. The EIA data imply that any such correction would be on the order of 1% or less.

With regard to ownership type, the EIA data do show persistent, significant differences in average price for publicly- *vs.* privately-owned companies. Figure 5 shows that a large proportion of consumers are served by publicly-owned companies. We have computed the state-level average price P_{ST} for IOU and POU companies separately and plotted these in Figure 6. The bars in this figure are the total number of consumers served by the POU and IOU sector in each state. These numbers are based on the 2014-2016 EIA data. There are significant differences in this price metric at the state level, and on a national average basis this price is about 15% lower for the public sectors. Figure 7 shows the POU and IOU prices (filled squares) aggregated to the census division/large state level, this time as time series for the years 2007-2016. The figure also plots time series of the standard deviation of prices (open squares), based on the difference between the regional average and the utility-level price. The regional data show a much clearer pattern of difference between IOU and POU companies. In general IOU prices are either higher (as in NE, MATL, PAC and CA) or there is not much difference between the two. The figure also shows that there is more price volatility and variability between companies (as measured by the standard deviation) in those regions where the IOU/POU difference is large. These are mostly

State	Bundled Avg ¢/kWh	Unbundled Avg ¢/kWh	Percent Consumers Unbundled
CA	15.8	18.5	0.7%
CT	19.0	19.3	25.1%
DC	12.5	13.8	6.9%
DE	13.8	14.4	4.4%
IL	10.9	11.4	20.2%
MA	16.7	18.3	14.3%
MD	13.0	14.1	13.2%
ME	14.8	15.4	92.2%
MI	12.6	13.0	0.0%
MT	10.2	9.4	0.0%
NH	16.1	15.9	5.6%
NJ	15.4	16.6	6.5%
NY	18.0	20.1	18.4%
OH	11.0	11.7	28.4%
PA	12.0	13.6	17.2%
RI	15.8	18.2	1.7%
VA	10.0	12.5	0.0%
US	11.9	14.7	6.5%

Table 3: For states with unbundled service, the consumption-weighted average price and percent of consumers on unbundled rates.

regions where restructuring of the electric utility industry is most advanced.

Based on EIA 2016 data, 27% of residential customers are served by POUs and the number of POU companies is about 7 times the number of IOUs, implying that the number of customers served by the average POU is about 1/17 that of the average IOU. Hence, for a sample of utilities to cover similar proportions of IOU and POU customers, it would be necessary to sample 4 or 5 POUs for each IOU. The EIA 861 monthly data include only a couple of large POUs, the EEI data include no POUs, and the TAP sample includes roughly the same number of POUs as IOUs, meaning that all these datasets under-represent the publicly-owned sector, which may result in a biased price estimate. In this paper we correct for any potential bias in two ways: by use of a correction factor for the EIA monthly and EEI data, and through re-weighting for the TAP sample. The

Year	1 NE	2 MATL	3 ENC	4 WNC	5 SATL	6 ESC	7 WSC	8 MTN	9 PAC	10 NY	11 FL	12 TX	13 CA
2006	-3.3%	0.0%	-0.2%	0.1%	4.3%	-0.7%	-1.3%	-0.4%	-6.8%	0.5%	-2.4%	-9.0%	-6.2%
2007	-2.3%	-0.2%	-0.7%	0.6%	2.8%	-1.8%	-1.3%	-0.7%	-10.0%	0.0%	-1.5%	-8.6%	-5.8%
2008	-2.5%	-0.1%	-0.9%	1.7%	1.5%	-1.1%	-3.3%	-1.1%	-13.8%	0.0%	0.3%	-6.8%	-3.5%
2009	-2.3%	-0.1%	-0.5%	2.6%	1.1%	2.2%	1.0%	-0.7%	-11.3%	-0.6%	0.4%	-7.5%	-3.9%
2010	0.2%	-0.8%	-0.8%	1.2%	0.6%	0.0%	-0.4%	-0.2%	-12.1%	-0.8%	2.3%	-5.1%	-3.0%
2011	1.2%	-1.0%	-1.5%	0.8%	1.0%	2.0%	0.1%	0.3%	-14.2%	-1.6%	2.0%	-3.7%	-2.6%
2012	0.0%	-1.8%	-2.2%	1.3%	1.2%	2.5%	1.7%	-0.2%	-14.2%	-0.9%	2.0%	-3.7%	-3.1%
2013	-0.9%	-0.9%	-4.9%	-0.7%	1.5%	-0.6%	0.4%	-0.7%	-13.4%	-0.5%	2.0%	-3.3%	-3.3%
2014	-1.1%	1.1%	-3.1%	-1.0%	1.7%	-1.0%	1.2%	-1.1%	-12.3%	-1.4%	1.2%	-3.3%	-2.7%
2015	-0.1%	0.7%	-1.7%	-1.3%	1.4%	-2.5%	1.5%	-0.9%	-9.9%	0.7%	1.1%	-3.1%	-3.1%
2016	0.9%	1.1%	-1.4%	-1.6%	0.7%	-2.2%	1.9%	0.1%	-8.7%	1.6%	1.4%	-1.9%	-3.2%

Table 4: Correction factor for IOU-only price estimates. The factor applied is 1 plus the number in the table.

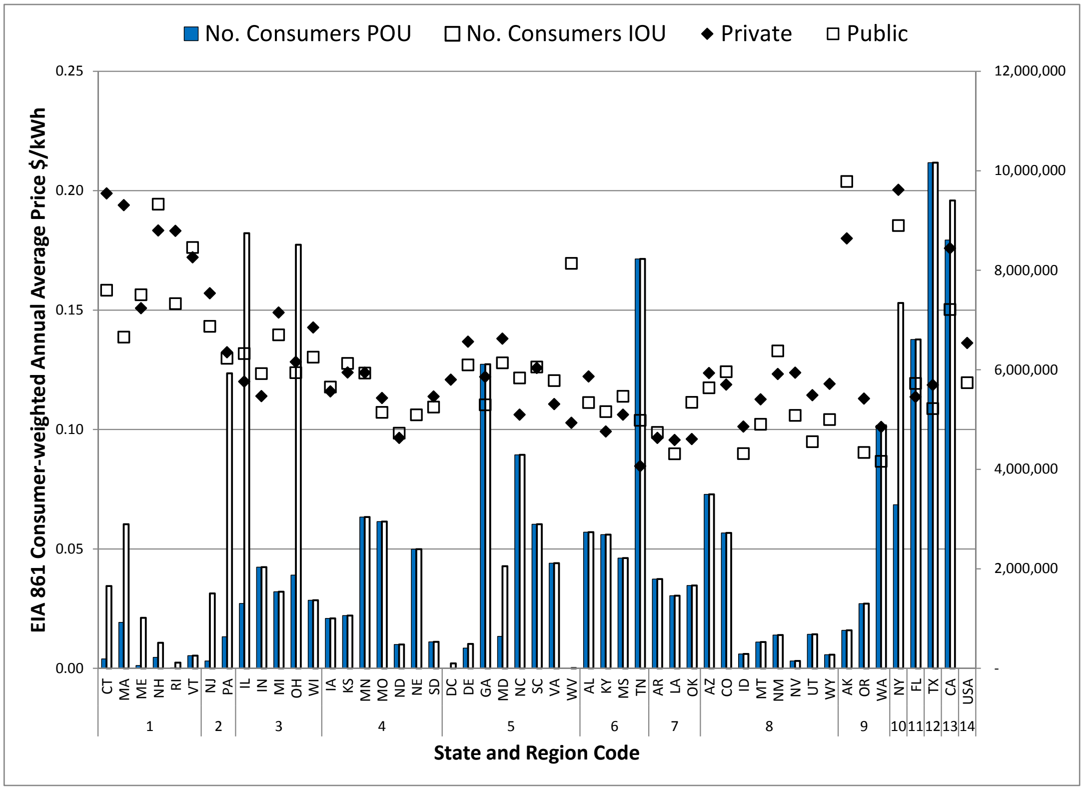

Figure 6: State-level average prices ($/kWh, left axis) for IOUs and POUs based on EIA 861 data for 2014-2016. The blue/open bars indicate the total number of consumers served by POUs/IOUs in the each state (right axis).

correction factor is defined as the ratio of the regional average price calculated from the full EIA 861 sample to that price calculated using only IOU companies. It therefore corrects for the under-estimate or over-estimate in IOU-only data. Table 4 shows values of the correction factor minus one, which corresponds to the magnitude of the correction as a percentage of the IOU-only price, for 2016 data. Negative values in the table mean that the IOU-only estimate should be reduced by the percentage shown in the table and vice versa. These factors are applied to the regional average and marginal prices calculated from the EEI data.

While the TAP database does include many POUs it still under-represents consumers served by this industry sector. We correct for this by adjusting the weighting used to compute regional averages for TAP data. In the first step, within a given region we define separate consumer-weighted regional average prices for the publicly- and privately-owned utilities in TAP. As in equation 8, this step uses the utility's consumer counts as the weight. In the second step we combine the IOU and POU results, this time using the total

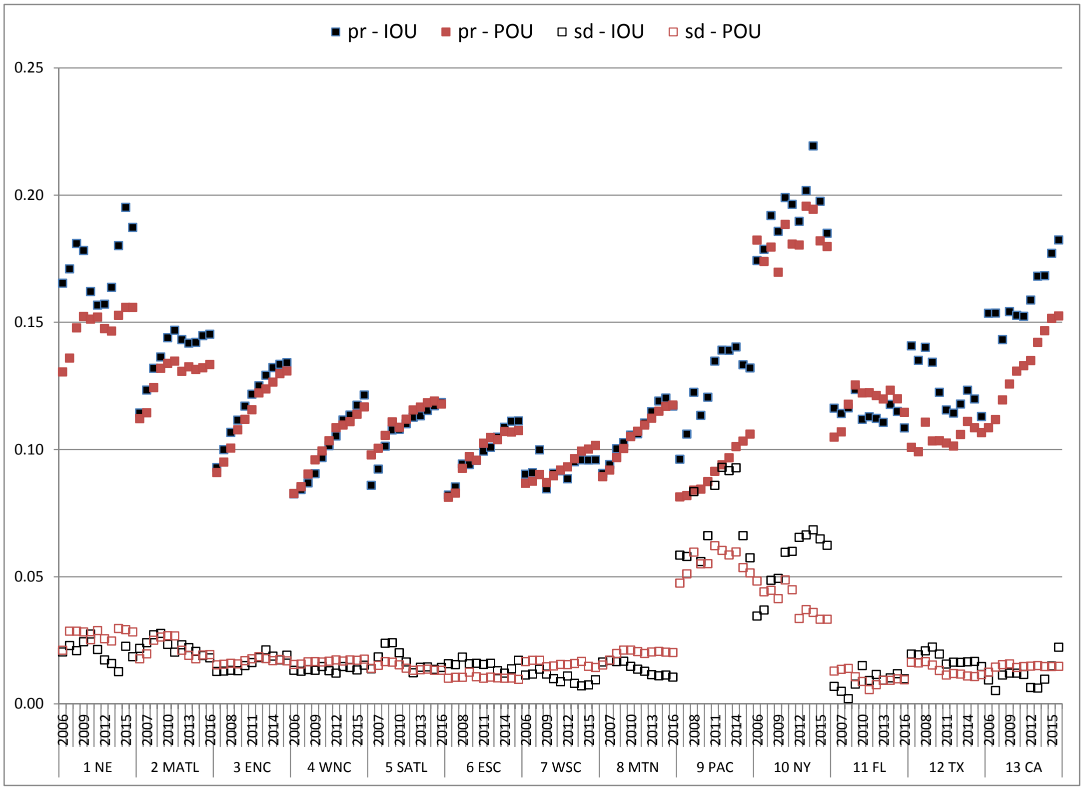

Figure 7: Filled squares: region-level average prices for IOUs (pr-IOU) and POUs (pr-POU) by year for EIA 861 data 2006-2016. Open squares: standard deviation for the regional price metric.

number of consumers by provider type from EIA 861 as the weight. This step effectively adjusts the relative weights of the TAP utilities so that the proportion of public/private sector consumers in the TAP calculation is the same as that of the full EIA 861 sample. The correction factors of Table 4 are not applied to the TAP prices.

3 Comparison Across Data Sources

In this section we present our calculation of regional weighted-average electricity prices for the EIA 861, EEI, RECS and TAP datasets. We focus on the years for which TAP data are available: 2008, 2011 and 2015. The RECS data are only available for 2009 and are compared to the 2008 data for the other sources. Figure 8 summarizes the regional average and marginal prices for all sources and data years. In this figure, average prices (as defined by equation 2) are indicated by markers and marginal prices (equation 3) by bars. The charts labeled 2008, 2011 and 2015 compare the EEI, TAP and EIA data. In the chart on the upper right, data from 2008 for TAP and EIA, and 2009 for RECS are shown. In this particular chart the method of calculating the TAP prices is modified to be more consistent with the RECS data. The TAP bills are calculated for the consumption levels shown in Figure 4, and the percentage of household by bin is used to weight the TAP results to give a single value for each region. This price now represents an average across the same distribution of monthly bills as are present in the RECS data. This approach results in a slight decrease of the average price (because the effect of the fixed charge is less pronounced), and a slight increase in the marginal price. The increase in the latter is substantial in regions 11 (FL) and 13 (CA).

Overall the four datasets agree reasonably well with significant discrepancies confined to particular regions and years. We note that in areas where the industry has undergone restructuring, utility bills tend to get more complicated, with an increasing number of small charges added to the bill. It can be difficult to identify and include all these charges in the TAP database. Particular effort was made in collecting the 2015 TAP data to include these charges; this presumably explains why there is better agreement in the TAP and EEI data in 2015 than in 2011. In the case of New York (region 10) in 2011 and later, many utilities include fuel cost adjustments which are not defined in the tariff, but vary depending on whether the utilities' annual fuel costs come in above or below expectations. Neglecting these charges seems to result in an underestimate in TAP, relative to both EEI and EIA, of average prices in NY.

In 2015 the EIA data provide a reasonable estimate of the average prices determined by EEI except for California. This pattern holds true for 2014 and 2016 (the latest EIA year available) as well. In the 2015 data there is a relatively large discrepancy in the TAP prices versus those estimated from EIA and EEI for region 9 (Pacific without California). This is due to the fact that in the TAP sample, the relative weight of utilities from Hawaii is larger than in the other datasets; because prices in Hawaii are in the range of 0.3 to 0.4 $/kWh, there is a significant effect on the regional price. In most regions, again excepting California, the marginal prices are slightly lower than average prices in both the EEI and the TAP datasets. In California, the marginal price is several cents per kWh higher than the average price, and recent data shows good agreement between TAP and EEI. Using the EIA estimate for California would underestimate the marginal cost of electricity in California by about 0.15 $/kWh.

3.1 Seasonal Effects

Seasonal information is available for the EIA 861 monthly, EEI, RECS and TAP data. Many utilities incorporate seasonal rates into their tariffs; the TAP data indicate that 43% of residential default tariffs include seasonal rates. In almost all cases, rates are defined for summer and winter seasons only, with the only exception being two utilities in the 2015 data with shoulder seasons defined in their tariffs. The TAP data tabulate which calendar months are assigned to a season; almost all tariffs define June through September as summer and about one half to two thirds define either May or October as summer. For this

Figure 8: Average prices (as defined by equation 2), indicated by markers, and marginal prices (equation 3), indicated by bars. Units are \$/kWh. The charts labeled 2008, 2011 and 2015 compare the EIA, EEI and TAP data; EEI and TAP values are for a billing period consumption of 1000 kWh. In the chart on the upper right data from 2008 for TAP and EIA and 2009 for RECS are shown, with the TAP values defined as weighted averages across all kWh tiers.

analysis, we assign the months May through September to summer and the rest of the year to winter in analysis of the EIA and RECS data. For EEI and TAP, we construct annual prices as weighted averages equal to (5/12) times the summer plus (7/12) times winter values.

The magnitude of seasonal variation is indicated in Figure 9, which tabulates the percent difference between the summer or winter price and the annual price for a selection of the datasets available. For EIA 861 monthly, only the average prices are available by season. For comparison to EEI and EIA, the TAP seasonal differences are calculated using IOUs

Average Price : percent difference in seasonal vs. annual value

Region	2009		2015 (IOUs only)						2015 (All)	
	RECS		EIA861 monthly		EEI		TAP		TAP	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1 NE	0.6%	0.3%	-3.3%	2.3%	-10.7%	7.7%	0.0%	0.0%	0.0%	0.0%
2 MATL*	2.1%	-1.1%	3.6%	-2.7%	2.0%	-1.4%	1.6%	-1.1%	1.5%	-1.1%
3 ENC	2.2%	-0.3%	2.3%	-1.6%	1.9%	-1.3%	1.6%	-1.2%	1.8%	-1.3%
4 WNC	7.9%	-2.0%	10.1%	-8.0%	10.8%	-7.7%	12.7%	-9.0%	11.6%	-8.3%
5 SATL*	3.3%	-0.9%	4.9%	-3.9%	3.6%	-2.6%	3.4%	-2.4%	2.8%	-2.0%
6 ESC	1.7%	0.1%	1.4%	-1.0%	1.4%	-1.0%	1.3%	-0.9%	1.1%	-0.8%
7 WSC*	3.6%	-0.3%	5.1%	-4.4%	4.2%	-3.0%	4.2%	-3.0%	7.5%	-4.9%
8 MTN	3.0%	-1.0%	3.1%	-2.5%	4.1%	-2.9%	7.7%	-5.5%	5.9%	-4.2%
9 PAC*	2.9%	-0.5%	0.0%	0.4%	1.7%	-1.2%	0.0%	0.0%	0.0%	0.0%
10 NY	1.9%	-0.6%	-4.8%	4.1%	-5.3%	3.8%	1.5%	-1.1%	2.5%	-1.8%
11 FL	1.8%	-1.2%	-1.3%	1.3%	-1.2%	0.8%	0.0%	0.0%	0.0%	0.0%
12 TX	-0.4%	1.0%	1.8%	-1.5%	0.7%	-0.5%	3.1%	-2.2%	1.7%	-1.2%
13 CA	0.2%	0.1%	8.4%	-6.8%	0.8%	-0.5%	0.2%	-0.1%	0.3%	-0.2%

Marginal Price : percent difference in seasonal vs. annual value

Region	2009		2015 (IOUs only)						2015 (All)	
	RECS		EIA861 monthly		EEI		TAP		TAP	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1 NE	-1.9%	1.6%			-11.2%	8.0%	0.0%	0.0%	0.0%	0.0%
2 MATL*	4.7%	-6.2%			4.6%	-3.3%	5.2%	-3.7%	5.1%	-3.6%
3 ENC	7.9%	-3.1%			3.9%	-2.8%	5.5%	-3.9%	5.3%	-3.8%
4 WNC	14.8%	-11.9%			17.1%	-12.2%	19.8%	-14.2%	17.6%	-12.6%
5 SATL*	8.8%	-5.7%			9.5%	-6.8%	11.1%	-7.9%	9.7%	-6.9%
6 ESC	3.0%	-3.8%			3.7%	-2.6%	6.1%	-4.4%	2.9%	-2.0%
7 WSC*	7.5%	-6.5%			8.9%	-6.4%	11.9%	-8.5%	14.5%	-9.7%
8 MTN	4.8%	-6.4%			7.3%	-5.2%	15.7%	-11.2%	12.2%	-8.7%
9 PAC*	0.4%	1.2%			2.2%	-1.5%	0.0%	0.0%	0.0%	0.0%
10 NY	3.6%	-2.8%			-5.2%	3.7%	2.5%	-1.8%	3.7%	-2.7%
11 FL	2.2%	-2.8%			-1.3%	0.9%	0.0%	0.0%	0.0%	0.0%
12 TX	1.7%	0.3%			1.4%	-1.0%	3.3%	-2.3%	2.8%	-2.0%
13 CA	3.3%	-1.6%			0.8%	-0.6%	0.8%	-0.6%	0.8%	-0.5%

Figure 9: Color-coded values of the percent difference between the summer/winter price and the annual price; blue (red) indicates that the seasonal value is lower (higher) than the annual.

only. The table entries are colored according to the sign and magnitude of the difference, with blue (red) indicating that the seasonal value is lower (higher) than the annual. The regional pattern of variation for the years displayed in Figure 9 is generally consistent across all years although the magnitude varies. The EIA 861 monthly data seem to indicate that the magnitude of seasonal variation is decreasing over time. The RECS data show the weakest seasonal variation, and the EEI data the strongest. In all areas except the northeast (regions 1 and 10), prices tend to be higher in summer than in winter. The EEI data show a large seasonal variation in region 1-NE, while all the other datasets indicate that this variation is minimal. The magnitude of seasonal variation is larger for the marginal than for the average price, and the increase in summer is typically larger than the decrease in winter. The EEI and EIA 861 monthly data include only IOUs, and the correction factor we calculate from EIA 861 has no seasonal variation. To look at the effect of provider type on seasonal variation we calculate summer and winter prices for the TAP data for IOUs only and for all companies combined. Including the POUs tends to reduce the magnitude of seasonal variation relative to IOU-only.

3.2 Effect of Household Baseline

The magnitude of household baseline electricity use (the e of equation 1) can also affect the value of the average and marginal prices. The only way to investigate this is using the TAP data. To do so, we computed summer and winter monthly bills for consumption levels of 1000, 2000, *etc.* up to 6000 kWh, and examined the variation in the average and marginal prices. Average prices decrease with increasing kWh by definition, while marginal prices may go up or down depending on whether the tariff includes ascending or descending block rates. In general, we find almost no variation in marginal price above 4000 kWh, *i.e.* the calculated marginal price remains essentially constant at each tier. Figure 10 illustrates the degree of change in the marginal price in moving from the 1000 kWh bill (the highest included in the EEI data), to 2000, 3000 and 4000 kWh. The figure also includes the change in price when moving from prices calculated for a fixed bill amount to prices calculated as a weighted average across all consumption levels, with the weights defined from the data in Figure 4. For most regions the variation is weak, with the exception of region 11-FL; in this region the price increases by about 13% in moving from 1000 to 2000 kWh, but does not increase significantly beyond that. Based on this analysis, the marginal prices derived from EEI may somewhat underestimate the true marginal price for households with larger baseline electricity use, but the effect is not large.

4 Time-of-Use Prices

Many utilities offer optional time-of-use (TOU) tariffs to residential customers. If a utility offers a TOU rate, it is included in the TAP database. The percent of utilities with optional TOU rates in the TAP database is 30% in 2008, 32% in 2011 and 20% in 2015. As the set of sample utilities is the same across data years, the data suggest that a declining number of utilities are offering the TOU option. With TOU tariffs, each hour of the day is allocated to two or three periods (on-peak, off-peak and shoulder) and the rate charged for electricity varies by period. Both the hours allocated to a given period and the rates charged may also vary by season. Most commonly, summer weekday afternoons are in the on-peak period and evenings and weekends are in the off-peak period, but there is considerable variation by utility. Figure 11 illustrates the allocation of hours for a random selection of tariffs in the TAP database. In this figure, the column labels 1-24 represent the hours of the day with hour 1 corresponding to midnight-1am *etc.* The TOU specification includes the season and the days of the week in which the period definitions are to be applied; days not included in the 'Peak Days' column are all off-peak.

In order to calculate customer bills for TOU tariffs, the billing period consumption first needs to be distributed over the TOU periods; for a given household, this distribution depends on the tariff used. Therefore, to proceed with bill calculations for TOU tariffs, we

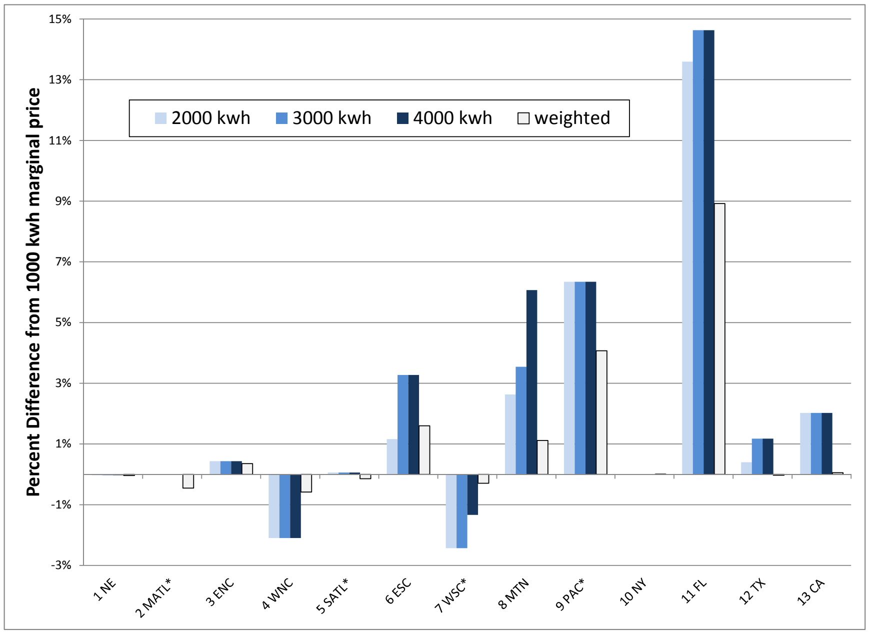

Figure 10: Percent change in the marginal price in moving from the 1000 kWh bill to 2000, 3000, 4000 kWh and the value calculated as a weighted average across kWh tiers.

need additional information about the time pattern of household electricity use. For this study we use an existing database of *EnergyPlus* [4] simulations of 3418 single-family residences drawn from the RECS 2005 sample [10]. Simulation input files were developed from the RECS data and information from a variety of other sources, and the output validated by comparing the statistical distribution of annual energy use by fuel type to the values published in RECS 2005 [10]. Here we use the hourly time series of total household electricity use to to create a model that defines, for each TOU tariff, the percentage of monthly electricity use that should be allocated to each TOU period.

The modeling steps are as follows:

1. For household j, tariff i, and month k, sum up the total electricity use in period p using the hour assignments illustrated in Figure 11 to generate a data set e_{ijkp}. Households and tariffs are aligned by census division so that if tariff i is defined for a state in census division 5, then only households in Census Division 5 are used to generate the e_{ijkp} for that tariff.

2. Convert e_{ijkp} to a percentage $z_{ijkp} = e_{ijkp}/e_{jk}$ where e_{jk} is the total consumption in month k.

3. Convert the monthly values z_{ijkp} to seasonal values z_{ijsp} by taking the simple average over all months appropriate to a given season; here the index s refers to summer,

Tariff ID	Season	Peak Days	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	All-year	Mon-Fri	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	0	0	0	0	0	0	0
2	All-year	Mon-Fri	0	0	0	0	0	0	2	2	2	2	2	1	1	1	1	2	2	2	2	0	0	0	0	0
3	All-year	Mon-Fri	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
4	All-year	Mon-Fri	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0
5	All-year	Mon-Fri	0	0	0	0	0	0	0	0	0	1	1	1	2	2	2	2	1	1	1	0	0	0	0	0
6	All-year	Mon-Sun	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0
7	All-year	Mon-Fri	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0
8	Summer	Mon-Sun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	0	0	0	0
8	Winter	Mon-Sun	0	0	0	0	0	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Summer	Mon-Fri	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	0	0	0	0
9	Winter	Mon-Fri	0	0	0	0	0	2	2	2	2	0	0	0	0	0	0	0	0	2	2	2	2	0	0	0
11	Summer	Mon-Fri	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0
11	Winter	Mon-Fri	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0
12	Summer	Mon-Fri	0	0	0	0	0	0	0	1	1	1	2	2	2	2	2	2	1	1	1	0	0	0	0	0
12	Winter	Mon-Fri	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	1	1	1	0	0	0	0	0
13	Summer	Mon-Sat	0	0	0	0	0	0	0	0	2	2	2	2	1	1	1	1	1	1	2	2	2	2	0	0
13	Winter	Mon-Sat	0	0	0	0	0	0	2	2	2	2	1	1	1	1	1	1	2	2	2	2	0	0	0	0
14	Summer	Mon-Fri	0	0	0	0	0	0	0	0	0	1	1	1	2	2	2	2	1	1	1	0	0	0	0	0
14	Winter	Mon-Fri	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0

Figure 11: Definition of off-peak, shoulder and on-peak hours, denoted (0, 1, 2) in the chart, for a random selection of tariffs in the TAP database. Labels 1-24 correspond to the hours 12-1 AM, 1-2 AM *etc.* This figure illustrates the variability in how TOU periods are assigned, which may depend on season and day-of-week as well as hour-of-day.

winter or all-year as is appropriate for the tariff.

4. For each tariff i and season s, define a typical value $\hat{z}_{isp}$ for the percentage of electricity use allocated to each period, by averaging across all household assigned to that tariff. In this average, the households are weighted using the RECS 2005 sample weight.

Figure 12 illustrates the output of this calculation for the TOU tariffs in the TAP 2015 dataset. These are organized along the horizontal axis by region and by season; each tariff either has hours defined for all months (A), or for summer and winter (S and W). Each bar corresponds to one tariff and season. To calculate the bill for a TOU tariff we generate the consumption in period p and season s by multiplying the total consumption by $\hat{z}_{isp}$; within each period the bill calculation then proceeds as for the default tariffs. For a given TOU period the tariff may include any feature that is used in non-TOU tariffs, such as ascending or descending block rates. While the bill calculation steps for the TOU tariffs are more involved, average and marginal prices are still calculated using equations 2 and 3.

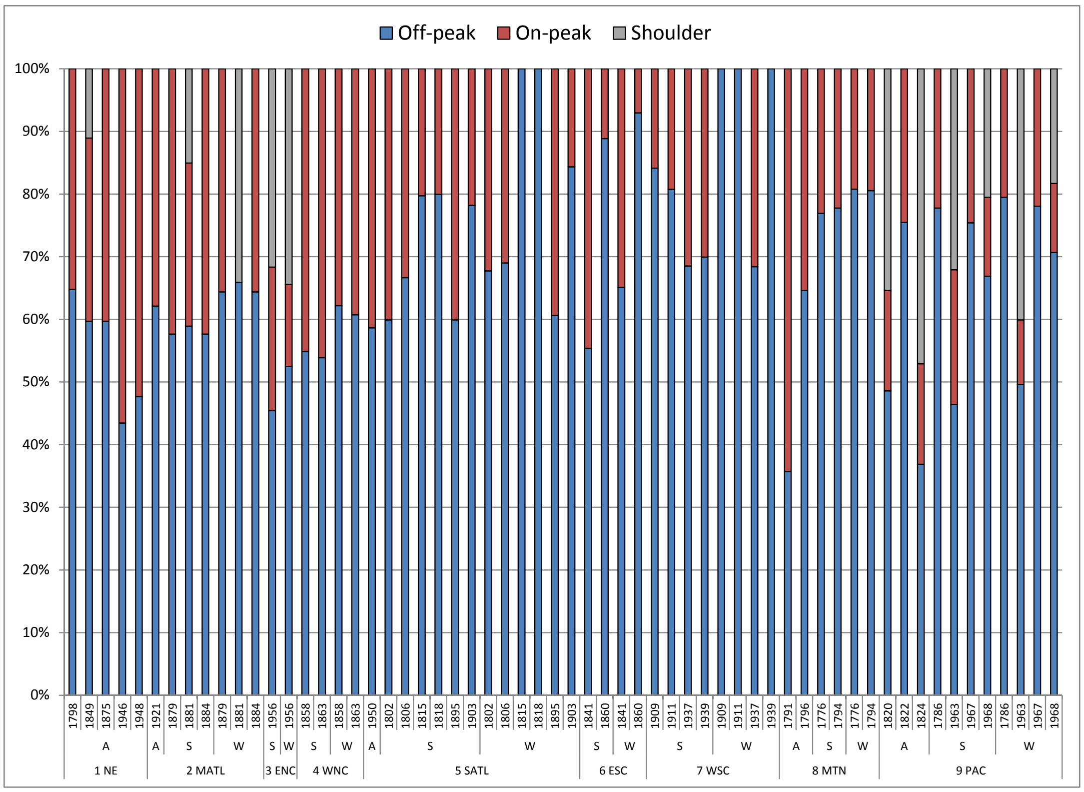

Figure 12: Distribution of billing period electricity use into TOU periods for all the TOU tariffs in the TAP 2015 data. The horizontal axis labels are the TAP internal tariff ID, a letter (A, S, W) indicating whether the hours distribution applies to all months, summer months or winter months, and the region label. Each tariff either has hours defined for all months (A), or for summer and winter (S and W).

In general, when a customer's electricity use is reduced, the fraction of the reduction assigned to each TOU period p will depend on the mechanism used to achieve the savings, and may be different from the fraction of baseline consumption allocated to p. For example, improving the efficiency of a peaking end-use such as air conditioning should have a higher proportion of savings allocated to on-peak relative to an efficiency improvement in a flat end-use such as refrigeration. Therefore, marginal prices for TOU tariffs include a *shifting* effect, *i.e.* an apparent price change induced by altering the way consumption is distributed across periods. To quantify this effect we split the marginal price calculations into two types. In the first type, we reduce the total bill as for non-TOU tariffs, holding the proportions across periods fixed. In the second type, which we term the TOU-shift price, we hold total consumption fixed and shift a quantity of kWh out of the peak period into the off-peak period. For tariffs with both shoulder and off-peak periods, the kWh shifted out of on-peak is allocated proportionally to the two non-peak periods. The shift price is calculated as the difference in the bill divided by the quantity of kWh shifted. Generally these two prices represent the value of reducing total demand versus the value of shifting demand to non-peak periods.

As an example, consider the case with two periods, on- and off-peak. The baseline total electricity use is e, and we define z as the fraction of electricity that is used in the on-peak period, *i.e.* on-peak use is $e_{\text{on}} = ze$ and off-peak use is $e_{\text{off}} = (1-z)e$. Generalizing equation 1, the bill is specified by a tariff that is a function of both e and z:

$$b = f(e, z) \tag{9}$$

The TOU marginal price is calculated by decrementing e but leaving z fixed:

$$m = \frac{f(e, z) - f(e - \Delta e, z)}{\Delta e}, \tag{10}$$

while the TOU shift price is calculated by holding e constant and modifying z:

$$r = \frac{f(e, z) - f(e, z - \Delta z)}{e\Delta z}. \tag{11}$$

In the latter case the total amount of energy shifted from on to off-peak is $e\Delta z$, so that is what appears in the denominator. For small Δe and Δz, we have

$$f(e - \Delta e, z) = f(e, z) - m\Delta e, \tag{12}$$

and

$$f(e, z - \Delta z) = f(e, z) - re\Delta z. \tag{13}$$

Figure 13 compares the default tariff marginal price, the TOU tariff marginal price with fixed proportions, and the TOU shift price for all those utilities in the TAP 2015 data that offer residential TOU tariffs. Since the TOU tariffs are only available for some utilities, consumer-weighted regional averages are not sensible for TOU prices, so we do the comparison at the utility level. The horizontal axis is organized by region, and the label includes the state for that tariff, but individual utilities are not identified in the figure. The data show that the marginal price calculated with the TOU tariff is comparable to the default marginal price, in some cases a little higher, in many cases a little lower. The shift prices vary across utilities, and are generally comparable to or lower than marginal prices. In two cases, the shift price is actually negative; this means that shifting electricity use from on to off-peak increases the bill. This occurs because the shift into the shoulder period pushes consumption up to the next tier, and the rate increase due to changing tiers is larger than the rate decrease due to switching periods.

In an application the value of electricity savings is determined by a combination of these two prices. The relative importance of the shift is determined by the load shape of the electricity savings, which in turn depends on the end-use that is affected by the change in

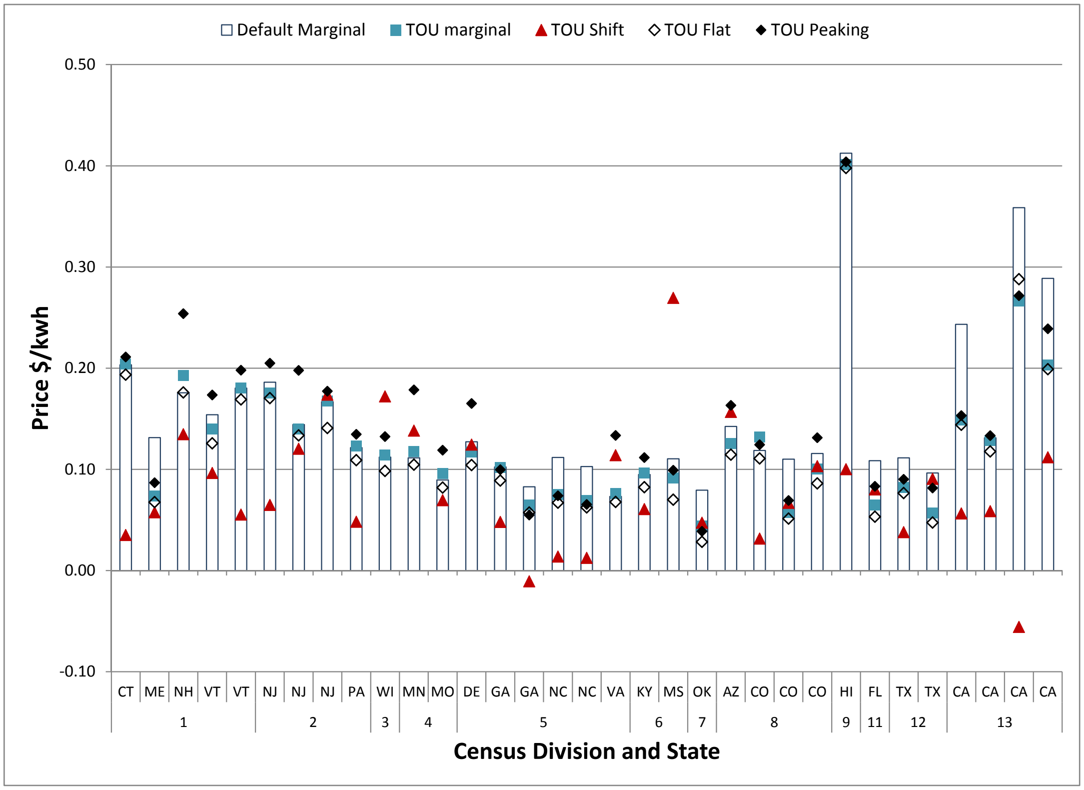

Figure 13: Comparison of the marginal prices for the default tariff (bars) and four TOU cases : with the distribution of electricity use across periods fixed (equation 10, blue squares), with zero decrement and a shift into on-peak (equation 11, red triangles), with a flat marginal load shape (equation 16, open diamonds), and with a peaking TOU load shape (equation 16, filled diamonds). The data are annual prices for the 2015 TAP utilities offering TOU tariffs.

demand. It is useful to consider two boundary cases, representing perfectly flat and strongly peaking load shapes. To first order the percent of electricity use in period p should be proportional to the number of hours in period p; this is exactly true for a perfectly flat load. Therefore, load shape effects can be captured by comparing the percent of electricity use to the percent of hours in each period. Consider again the case with two periods, on- and off-peak. The number of hours in each period are n_{on} and n_{off}. For a perfectly flat load with hourly average magnitude c,

$$e_{\text{on}} = cn_{\text{on}}, \quad e_{\text{off}} = cn_{\text{off}}, \tag{14}$$

which implies that

$$\frac{e_{\text{on}}}{e_{\text{on}} + e_{\text{off}}} = \frac{n_{\text{on}}}{n_{\text{on}} + n_{\text{off}}}. \tag{15}$$

To represent this case we performed a marginal price calculation in which the decrement in each period is defined as the percent of all hours that fall into that period times Δe,

$$\Delta e_{\mathrm{on}} = \frac{n_{\mathrm{on}}}{n_{\mathrm{on}} + n_{\mathrm{off}}} \Delta e. \tag{16}$$

and similarly for the other periods. The output of this calculation is represented by the open diamonds, labelled TOU Flat, in Figure 13.

For a peaking load shape we expect that the hourly energy use in the on-peak period would be higher than the off-peak period. We can represent this effect using a new parameter h, defined by the relation

$$e_{\mathrm{on}} = hcn_{\mathrm{on}}, \quad e_{\mathrm{off}} = cn_{\mathrm{off}}. \tag{17}$$

The multiplier h is equal to the ratio of the average hourly on-peak load to the average hourly off-peak load. To estimate a typical value of h for a peaking load, we examined the air-conditioning load shapes available in the RECS simulation database [10]. We used the TOU hours definitions to allocate air-conditioning electricity use to TOU periods, and compared the resulting e_{on} and e_{off} to the values of n_{on} and n_{off} defined by the tariff. For this calculation, for tariffs having three periods, the off-peak and shoulder hours were summed to create a single non-peak period. The value of h in equation 17 was calculated for summer and winter months separately. The range of h is about 1.5 to 2.5 during summer months, and it 1.1 to 3.1 during winter months. As the summer season is where most air-conditioning energy use occurs, we use 2.5 as a representative value for peaking load shapes. In this case the on-peak marginal decrement is

$$\Delta e_{\mathrm{on}} = h \frac{n_{\mathrm{on}}}{n_{\mathrm{on}} + n_{\mathrm{off}}} \Delta e; \tag{18}$$

the remainder (if any) is allocated to the off-peak and shoulder periods proportionally. The marginal prices calculated using this method are shown as filled black diamonds, labelled TOU peaking, in Figure 13. The peaking marginal price is higher than the flat marginal price, and also higher than the default price, for most TOU tariffs. In many cases the range of difference is very small; large premiums associated with peaking loads are found primarily in the Northeast, while significant discounts for TOU relative to the default tariff are seen in 3 out of 4 California utilities.

To our knowledge very few utilities have mandatory TOU tariffs for residential customers (only one utility in the TAP 2015 data has a default TOU tariff). As long as TOU tariffs are optional, there is little incentive for a consumer to opt in if TOU prices are higher. The 2008 Federal Energy Regulatory Commission (FERC) staff report on demand response [8] provides a figure (Figure III-5) that indicates approximately 1.2 million residential customers were on TOU tariffs in 2007; based on the total residential consumer count from EIA Form 861 this corresponds to less than 1% of all consumers. Later FERC reports focus on customer enrollment in time-based demand response programs and do not explicitly consider TOU tariffs. The 2017 FERC report [8] shows that the penetration of advanced meters has increased from about 5% of all meters in 2008 to around 40% of all meters in 2016. The TAP data show that many utilities require commercial customers to use TOU tariffs [2], so the penetration for the residential sector may be significantly lower.

Even with residential advanced metering in place, it is not clear that these are being used to implement TOU pricing. The TAP utility sample actually shows fewer TOU tariffs offered in 2015 than in 2011. Given the likely low penetration of TOU rates, the relatively small differences in marginal prices shown in Figure 13, and the disincentive for consumers to opt into TOU if TOU prices are higher, we conclude that these tariff structures do not need to be included in general residential consumer price analyses.

5 Conclusions

In this paper we have provided a comprehensive review of data and methods available to calculate residential electricity prices. Our approach emphasizes that provision of electricity is a service, and supply of the energy commodity is just one aspect of that service. In this view the consumer bill is the starting point for the data analysis, and all prices are derived from bills. We define three types of price based on the bill consumption and expenditures: average, commodity and true marginal. The average price is the ratio of expenditures to consumption, the commodity price is the ratio of incremental cost to incremental consumption with some averaging included (over tiers, over households or over tariffs depending on the data source), and the true marginal is the cost of the next kWh for a single household. These prices have been calculated at the household and utility level, and as aggregated consumer-weighted regional values which are compared across data sources.

We have reviewed four data sources: EIA Form 861 annual and monthly, EEI Typical Bills reports, RECS 2009 household billing data, and the TAP tariff data compiled and analyzed at LBNL for 2008, 2011 and 2015. Each dataset has strengths and weaknesses:

- the EIA data provide complete coverage of the utility industry but can only be used to calculate average prices;
- the RECS data provide detailed information about actual households but are only updated every few years; our analysis shows that RECS data seem to under-estimate seasonal variation in prices;
- the EEI data provide sufficient information to calculate seasonal average and marginal prices but sample only IOUs;
- the TAP data provide detailed information about tariffs, and are the only dataset that allow TOU prices to be evaluated explicitly; TAP data are updated infrequently and in some regions the proliferation of small line-item charges in the tariff makes it challenging to capture all the relevant data.

In consumer-oriented analyses of the potential economic benefits of electricity demand management, the marginal price provides the best estimate of the value of energy savings to the consumer. In addition, for many residential end-uses the magnitude of electricity consumption varies both geographically and by season. This study shows that differences between marginal and average prices, and variation by region and by season in both marginal and average prices, are quantitatively significant. Only the EEI data and the TAP data provide the level of detail necessary to correctly capture this variability. In general these two datasets provide consistent results with small quantitative differences. For particular years and regions there can be larger discrepancies, but for the most recent (2015) data the EEI and TAP data agree well for both marginal and average prices.

The value of the TAP data is that it allows exact calculation of bills under any scenario, which provides a 'test bed' for understanding when and by how much additional details of consumer electricity use affect the valuation of changes to demand. However, given the high level of effort required, TAP is infrequently updated and the sample size cannot be increased significantly. The EEI data have the advantage that they are updated annually, and by making use of the other available data sets, we have shown that limitations of the EEI data either are not significant, or can be corrected for. These limitations are:

- EEI data are IOU-only. Our analysis of EIA 861 data showed significant and persistent differences in the utility-level average price based on ownership type. Therefore, we correct for potential bias in EEI prices by applying correction factors, computed from the EIA 861 data, shown in Table 4.

- EEI only includes bundled service data, not unbundled data. We used the EIA data to quantify the difference in average price based on service type (bundled or unbundled). We found that average prices for unbundled service are generally higher than for bundled service, but on a regional average basis prices computed with and without unbundled service included differ by less than 1%. Therefore, corrections for this effect would be negligible.

- EEI reports typical bills for consumption levels up to 1000 kWh. The RECS data show that only 37% of household bills are for 1000 kWh or less, with the remainder distributed over the range of 1000-4000 kWh, as illustrated in Figure 4. We used the TAP data to compare, on a regional basis, the marginal price calculated for a 1000 kWh bill to that calculated as an average over the distribution of household bills in Figure 4. The difference is on the order of a few percent except in region 11-FL where it is 9% (see Figure 10). Therefore, the effect of using 1000 kWh bills to represent household bills over the range 1000-4000 kWh is unlikely to be significant in any national-scale analysis, but may be important in region-specific cases. When necessary the TAP data could be used to develop correction factors for this effect.

- EEI data do not include optional time-of-use (TOU) tariffs. We used the TAP data, and a model we developed to distribute monthly electricity consumption across TOU periods, to calculate marginal prices for TOU tariffs in a variety of scenarios representing different types of marginal load-shape. We found that TOU marginal prices may be higher, lower, or very similar to those for default tariffs. Given that TOU tariffs are optional, and consumers are unlikely to opt into a tariff with higher prices, the penetration of TOU rates in the residential sector is low, and it should not be necessary to explicitly consider these rate types in general analyses.

In summary, we have quantified the variability by region, season, and price type of electricity price estimates derived from the most commonly used data sources. We have also provided a methodology for developing detailed price estimates from EEI data, supplemented by information from EIA 861. This information will allow analysts to determine whether simple price estimates, such as the average price based on EIA 861 data, are sufficient to represent the value to consumers of a policy or program impact. For example, the DOE Appliance Efficiency Standards Program [3] typically develops highly detailed LCC analyses, including household-level data on consumer characteristics that affect energy consumption and operating costs. If the household-level analysis shows significant variation in energy savings by region or season, then it would be appropriate to include the corresponding detail in the electricity prices. In cases where the costs of a measure are roughly equal to the estimated potential benefits, then even small differences between average and marginal prices could be important to correct evaluation of the net benefit.

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