

UC Berkeley

Recent Work

Title

Do Americans Consume Too Little Natural Gas? An Empirical Test of Marginal Cost Pricing

Permalink

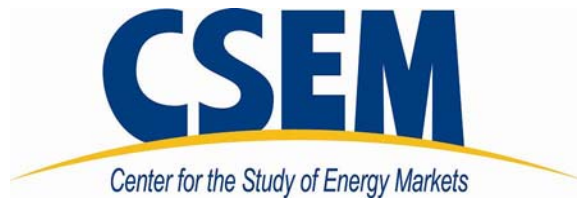
<https://escholarship.org/uc/item/2m41d45s>

Authors

Davis, Lucas
Muehlegger, Erich

Publication Date

2009-09-21



CSEM WP 194

**Do Americans Consume Too Little Natural Gas?
An Empirical Test of Marginal Cost Pricing**

Lucas W. Davis and Erich Muehlegger

September 2009

This paper is part of the Center for the Study of Energy Markets (CSEM) Working Paper Series. CSEM is a program of the University of California Energy Institute, a multi-campus research unit of the University of California located on the Berkeley campus.



2547 Channing Way
Berkeley, California 94720-5180
www.ucei.org

Do Americans Consume Too Little Natural Gas?

An Empirical Test of Marginal Cost Pricing

Lucas W. Davis

Erich Muehlegger*

September 2009

Abstract

A standard result in regulation is that efficiency requires that marginal prices be set equal to marginal costs. This paper performs an empirical test of marginal cost pricing in the natural gas distribution market in the United States during the period 1989-2008. For all 50 states we reject the null hypothesis of marginal cost pricing. Departures from marginal cost pricing are particularly severe in residential and commercial markets, where we find average markups of over 40%. Based on conservative estimates of the price elasticity of demand these distortions impose hundreds of millions of dollars of annual welfare loss. Moreover, the current pricing schedules are an important pre-existing distortion which should be taken into account when evaluating carbon taxes and other policies aimed at addressing external costs. Current markups for residential and commercial customers are already equivalent to a tax of over \$200 per metric ton of carbon, considerably higher than the range envisioned by most economists.

Key Words: Efficient Pricing, Marginal Cost Pricing, Natural Gas

JEL: D42, L50, L95, Q48, Q54

*(Davis) Haas School of Business, University of California, Berkeley and National Bureau of Economic Research. email: ldavis@haas.berkeley.edu. (Muehlegger) John F. Kennedy School of Government, Harvard University. email: Erich_Muehlegger@hks.harvard.edu. We thank Soren Anderson, Severin Borenstein, Meredith Fowlie, Ed Glaeser, Ryan Kellogg, Erzo Luttmer, Peter Reiss, Catherine Waddams, Matt White, and seminar participants at the University of California Energy Institute and the University of Michigan for helpful comments.

1 Introduction

Energy plays a central role in determining our overall economic well-being, from heating and cooling our homes and businesses to determining the cost and composition of goods and services produced in the economy. It is crucial that energy be priced appropriately to correctly encourage efficient choices within and across different energy sources. These choices are particularly important given recent increased attention to the external costs of energy. In the United States, 81% of greenhouse gas emissions are derived directly from the production and consumption of energy. There is a great deal of public interest, therefore, in regulating energy markets in such a way that prices accurately reflect both private and social costs.

Perhaps the most important and widely accepted rationale for public intervention in energy markets is natural monopoly. Left unregulated, a monopoly maximizes profit by pricing above marginal cost, resulting in a level of output below the socially optimal level. A standard result in regulation is that efficiency requires that marginal prices be set equal to marginal costs. This eliminates the deadweight loss associated with the monopoly and brings the level of production to the socially optimal level. The regulator then recoups the monopolist's fixed costs through public subsidies or through fixed fees. Although there is widespread agreement on the theoretical benefits of marginal cost pricing, there is relatively little evidence comparing actual regulated prices to this ideal.

This paper applies the standard natural monopoly framework to natural gas distribution in the United States. In this paper, we examine the following questions: (1) How do prices compare to marginal costs? (2) How much welfare is lost from the observed deviations from marginal cost pricing? (3) What explains the observed pattern of prices schedules? (4) Do municipally-owned distribution companies recoup the fixed costs of operation differently than regulated investor-owned distribution companies? (5) What do the observed prices imply for the likely effectiveness of a carbon tax or other policy aimed at addressing the external costs of energy consumption?

Examining data from 1989-2008, we find that price schedules differ substantially from the theoretical ideal. Individually and jointly, for all 50 states we reject the null hypothesis of marginal cost pricing. In practice, most distribution companies charge prices approximately equal to average cost, including the amortization of capital expenditures. Based on conservative estimates of the price elasticity of demand, our results imply that the current pricing system yields annual welfare losses of \$2.6 billion compared to marginal cost pricing.

Our results are relevant for evaluating the likely effectiveness of proposed legislation which would place a tax on natural gas and other sources of carbon emissions. Our results indicate that, on average, customers already face average markups of 36% above the marginal cost. The average customer markup (\$2.57 per McF) is equivalent to a carbon tax of \$173 per metric ton, higher than the level of a carbon tax envisioned by most economists.¹ As a point of comparison, Nordhaus (2008) adopts a carbon tax of \$35 per metric ton of carbon. Based on \$35 per ton, therefore, customers are already facing a marginal price that is above the social marginal cost of natural gas and any policy which further increases the marginal price will further reduce consumption below the efficient level. The broader policy lesson from our analysis is that pre-existing distortions from imperfect regulation are important to consider when evaluating carbon taxes and other policies that would increase the marginal price of energy products.

We then discuss possible explanations for the observed rate structures. Cost recovery is a central feature of the current regulatory environment, but cost recovery alone cannot explain why per unit prices tend to be marked up considerably while fixed fees (e.g. monthly fixed fees) are consistently very low across customer classes. In part, this preference for low fixed fees may reflect efforts by regulated companies to maximize the total number of customers and thus the total rate base (see Sherman and Visscher, 1982). Distributional considerations provide an additional and complementary explanation. Under current price schedules, high-volume customers pay a disproportionately large share of fixed costs and attempts to “levelize” price schedules typically face substantial political opposition because higher fixed fees would result in increased expenditures for low-volume customers.

Finally, the paper considers available policy approaches for addressing these departures from marginal cost pricing. One alternative is public ownership. Direct subsidies from general tax revenues could allow municipally-owned companies to charge prices which are closer to marginal cost. In order to explore this possibility we assemble an alternative utility-level dataset and compare revenues from municipally-owned and investor-owned distribution companies. Exploiting variation in utility ownership among markets with similar observable characteristics, we find that approximately 25 percent of a municipally-owned utility’s fixed costs are borne by taxpayers rather than consumers of natural gas. Lower revenue requirements allow municipally-owned companies to charge marginal prices which are closer to marginal cost, reducing deadweight loss. Of course, these subsidies must

¹U.S. Department of Energy, Energy Information Administration, “Documentation for Emissions of Greenhouse Gases in the United States (2005)”, October 2007, DOE/EIA-0638, Table 6-4. There are .0148 metric tons of carbon per thousand cubic feet(McF) of natural gas.

be financed through taxes. Because the government cannot collect non-distortionary taxes, the welfare effects of public provision are ambiguous - welfare for natural gas consumers rises, but tax collection introduces distortions in other parts of the economy.

The paper proceeds as follows. Section 2 describes relevant background information about the regulatory environment faced by natural gas distribution companies. Section 3 describes the 20-year state-level panel of prices and quantities assembled for the analysis. Section 4 presents the results of our test of marginal cost pricing and measures of the total welfare loss compared to marginal cost pricing. Section 5 discusses the causes and consequences of the current rate structure with emphasis on implications for carbon policy. Section 6 compares regulated prices for municipally-owned and investor-owned distribution companies and section 7 concludes.

2 Regulatory Background

The natural gas market in the United States consists of three main players: gas producers, interstate pipeline operators, and local distribution companies (“LDCs”). Gas producers explore for and produce natural gas. Interstate pipeline operators transport natural gas from producing areas to consuming areas. LDCs, in turn, purchase natural gas at the “city gate” and distribute it through a distribution network to four different customer classes: residential, commercial, industrial, and electric power.

The costs in this market are widely understood. The main fixed cost for the LDC is the installation and maintenance of the pipeline network. In addition, LDCs incur costs installing and maintaining gas meters, processing bills, and taking customer service calls. These costs depend critically on the total number of customers, and the “marginal customer cost”, i.e. the cost of adding an additional customer to the network is substantial. In contrast, the cost of providing an additional unit of gas to an existing customer, or “marginal commodity cost” is just the commodity cost of the natural gas. The commodity cost is measured by the city gate price, the price at which the LDC receives natural gas.² The marginal cost of distributing gas through the local pipeline network is virtually zero for all classes of consumers. Our conversations with industry participants and examinations of industry filings confirm that there are line losses, particularly in older pipeline

²From a research perspective, a significant advantage of natural gas distribution compared to many other markets is that marginal costs of the LDCs are observed. This is important because although an extensive literature in industrial organization has been developed for inferring marginal cost based on pricing behavior, this approach is problematic for studies of regulated firms because prices for these firms are established by regulators, causing the key identification assumption to fail. Not only do we observe marginal costs, but they are observed for all 50 states, at a monthly frequency, going back to 1989, and during an unprecedented increase in natural gas prices since 2000.

networks, but that these costs are negligible, representing a tiny fraction of total costs.

LDCs are regulated by state utility commissions which set tariff schedules for each customer class using traditional rate-of-return techniques.³ Regulators create price schedules for each customer class to equate revenues and costs so that economic profit is zero,

$$\sum_{i=1}^I \text{Revenue}(p_i) = sB + \text{expenses}$$

where $\text{Revenue}(p_i)$ is the revenues generated from customer class i given the price schedule p_i , s is the allowed rate of return, and B is the rate base, the total value of the firms investment. Although regulatory commissions differ in how B is measured, this always includes capital investments such as the distribution network itself, but not *expenses* such as labor expenditures and other variable operating costs.

There are many different price schedules which satisfy the zero profit condition and several previous studies have considered the question of which schedule yields the highest level of utility. If constrained to use linear prices, Boiteux (1956) shows that the welfare-maximizing price markup is proportional to the inverse of the elasticity of demand. Specifically, if a monopolist produces N goods (or serves N different customer classes) with total cost function $C(x_1, x_2, \dots, x_I)$ and faces inverse demand function $p_i(x_i)$ for good i , a social planner constrained to using linear prices can maximize social surplus by setting prices

$$\frac{p_i - \frac{\partial C(X)}{\partial x_i}}{p_i} = - \left(\frac{\partial p_i}{\partial x_i} \frac{x_i}{p_i} \right) \left(\frac{\lambda}{1 + \lambda} \right),$$

where λ is a non-negative constant. These prices are called ‘‘Ramsey-Boiteux’’ prices because the problem considered by Boiteux (1956) is formally identical to the constrained maximization problem solved by Ramsey (1927). In practice, state regulators are not constrained to linear prices and instead typically allow LDCs to collect revenues through two-part tariffs.⁴ First, LDCs typically charge customers a fixed fee, typically levied monthly, that does not depend on the level of consumption. This fee varies by customer class - typically, industrial customers pay a higher

³See VHV (2005) for more information about natural gas regulation in the United States. Price controls on wellhead prices were a major feature of the U.S. natural gas market for much of the post-war period (see e.g. Davis and Kilian, 2009) but were terminated in 1989 at the beginning of our sample period.

⁴Typically LDCs use simple two-part tariffs, although multiple-part tariffs are not uncommon. We examined the 2007 tariff schedules of the twelve largest investor-owned distribution companies and the six largest municipally-owned distribution companies. Of the LDCs we surveyed, ten use multiple-part tariffs for at least one category of customers.

monthly fee than residential or commercial customers. In some cases, the fixed fee also varies within customer class - for example, residential customers who use natural gas for heating may be charged a different fee than residential customers who do not use natural gas for heating. Second, customers pay a per unit price for each unit of natural gas that is consumed. This price includes a commodity charge for natural gas purchased on their behalf by the local distribution company. Commodity costs change throughout the year with the LDCs procurement costs and typically changes in commodity costs are passed on relatively quickly to final customers.⁵ In addition to commodity costs, most companies also charge customers a per unit “transportation charge” per unit of natural gas consumed. This is typically a price per unit, though in some cases commodity costs are marked up by a fixed percentage. As we illustrate in Section 4, these per unit fees imply that LDC revenues are highly seasonal with LDCs collecting a large share of their total annual revenue during cold, high-demand winter months.

As first suggested by Coase (1946), two-part tariffs can be adjusted such that the price per unit is equal to marginal cost and the fixed fee set to cover total firm costs. For the relevant case with declining average costs and constant marginal costs, this implies that the fixed fee would be set equal to each customer’s share of the LDC’s fixed costs. Ng and Weisser (1974) and Sherman and Visscher (1982) extend the analysis of two-part tariffs, solving for optimal tariffs with and without revenue constraints. Sherman and Visscher show that the utility-maximizing tariff is such that the per-unit price is equal to the marginal commodity cost, and the fixed fee is equal to the marginal customer cost. If this efficient two-part tariff is not sufficient to cover the monopolist’s fixed costs, then both prices are marked up by an amount inversely proportional to the elasticity of demand for that margin.

3 Data

To perform the test of marginal cost pricing, we assembled a 20-year panel of natural gas sales and prices at the state-level. Our sample includes the entire period for which data are available, January 1989 through December 2008. Natural gas sales and prices come from the U.S.

⁵Friedman (1991, Section 3) provides a fascinating description of electricity and natural gas ratemaking in California under the California Public Utility Commission. Typically every three years there is a rate case with more frequent rate adjustments for commodity cost changes. “Substantively, each case proceeds in the same way. First, the utility’s revenue requirement and marginal costs are determined. Second, the commission comes to a broad decision about how to allocate that revenue among customer classes. Finally, actual rates within classes are set to raise the allotted revenue. See also Kahn (1994, Chapter 4) for additional description of the rate making process including a detailed example from Pacific Gas and Electric.”

Department of Energy, Energy Information Administration, “Natural Gas Navigator”. These data describe natural gas sales separately for residential, commercial, industrial, and electric utility customers. The Department of Energy constructs these data using a monthly survey (EIA Form-857) of natural gas distribution companies. In states with retail competition such as Georgia, Maryland, New York, Ohio, Pennsylvania, and Virginia, this information is supplemented using information from a monthly survey of natural gas marketers (Form-910). Thus, these data reflect total sales by state and month for all end-users. See Department of Energy, Energy Information Administration, “Definitions, Sources and Explanatory Notes” for details.

In this paper, we focus on sales to residential, commercial and industrial customers. We omit electric utility consumers. These facilities consume sufficiently large amounts of natural gas such that it is often profitable to build a dedicated line directly to an interstate pipeline, contract with suppliers directly and bypass the LDC. Consequently, LDCs have very little bargaining power with respect to electric utility customers and they tend to face very different price schedules from other customers. Similarly, among commercial and industrial customers, we exclude what are called “non-core” customers.⁶ Whereas “core” customers must buy from the LDC, “non-core” customers by virtue of their size or other factors can buy from third parties and then contract with the LDCs for transportation services only. Much like electric utility customers, non-core customers have negotiating power which allows them to typically obtain price schedules that are different from the schedules faced by most customers. Both the prices and quantities used in the analysis exclude non-core customers.

Prices are available by state, month, and customer class and include all charges paid by end-users including transportation costs as well as all federal, state and local taxes. Also available by state and month are city gate prices, the price paid by the LDC when they receive deliveries at the entrance to the distribution network. Table 1 presents descriptive statistics for the monthly data: consumption and average delivered prices by customer class, city gate prices, the spot price for North Sea crude oil (Brent Crude Spot Price), and heating degree days. All dollar values in the paper have been normalized to reflect year 2007 prices. In addition to the monthly survey data from EIA Form-857, we assembled annual utility-level data for the universe of distribution companies delivering natural gas to end users from EIA Form-176. For each LDC, we observe annual sales,

⁶While a relatively high proportion of commercial demand comes from “core” customers, most industrial customers contract with wholesaler natural gas providers directly. From 2002 to 2007, approximately, 79% of commercial natural gas demand came from “core” customers. For industrial demand, approximately 23% of demand came from “core” customers.

revenues and customers by class. In addition, we know firm ownership, which allows us to compare regulated prices of investor-owned and municipally-owned distribution companies in Section 6.

City gate prices play a critical role in the analysis that follows because they represent the marginal cost of natural gas for LDCs. Costs reported on EIA Form-857 represent, “the total cost of those volumes, including any and all demand charges, commodity charges, monthly minimum bill and/or take-or-pay charges, surcharges, refunds in the form of reduced charges, charges incidental to underground storage of company-owned gas, and transportation charges paid or incurred to deliver gas to your distribution area.” Although many of these costs indeed reflect the true marginal cost of natural gas to the LDC, one might be concerned, for example, by the monthly minimum bill charges which should be correctly thought of as a fixed fee rather than as a marginal cost. In addition, LDCs enter long-term contracts and engage in hedging transactions so costs in a particular month may be a poor proxy for marginal commodity costs. The ideal measure of marginal cost would reflect the true marginal cost of gas to the LDC, net of all fixed fees and any other costs that do not vary with the amount of natural gas procured.

To address these concerns, we also perform our empirical test of marginal cost pricing using an alternative set of city gate prices derived from an entirely independent source. These alternative city gate prices come from Platts’ GASdat database and consist of daily natural gas spot prices from 131 different locations.⁷ Platts obtains these prices via surveys of trades made at each location and they represent true natural gas spot prices. We aggregate these city gate prices to the monthly level and then calculate state averages across all locations in a given state. For states without Platts survey locations, prices from the closest available location are used.⁸ Table 1 reports summary statistics for both measures of the city gate price. The price from the EIA tends to be somewhat higher, consistent with including additional non-marginal costs. Overall, however, the two prices track each other fairly accurately and the correlation between the two prices is 78.2%.

Although the analysis which follows is performed at the monthly level, it is important to point out that city gate prices vary daily. Although natural gas storage dampens price volatility compared to e.g. wholesale electricity prices, there is still a substantial amount of day-to-day variation in natural gas city gate prices and one could envision a system in which the per unit price faced by

⁷In practice LDCs procure natural gas both on the spot market and in a forward market called the “bidweek market” in which the LDC purchases a specified volume of natural gas every day over the course of a month. Participating in this forward market reduces the volatility of expenditures but not the marginal cost of natural gas because at the margin, LDCs always have the option to buy (or sell) natural gas on the spot market. See Borenstein, Busse, and Kellogg (2009) for a detailed description of how LDCs procure natural gas.

⁸Both Alaska and Hawaii lack Platts survey locations. Since Alaska and Hawaii are the states with the lowest and highest average City Gate natural gas prices in the EIA data, we do not impute a Platts prices for these states.

consumers was continuously adjusted to reflect market conditions. Performing the analysis at the month level abstracts from this variation so our measure of deadweight loss will understate the gains from moving to true “real-time” marginal cost pricing for natural gas. In future research it would be interesting to examine this day-to-day volatility explicitly and calculate the potential social gains to a pricing system in which the marginal price faced by consumers was continuously updated.

4 Results

4.1 A Test of Marginal Cost Pricing

This section describes our test of marginal cost pricing. Because the marginal cost of natural gas distribution is essentially zero, efficiency requires per unit prices to be equal to the marginal commodity cost of natural gas. First, for each state, month, and customer class we calculate “net revenue”, the total revenue collected by LDCs net of commodity costs. Next, we test if net revenue is a function of the level of gas consumption.

The best way to understand our test is by example. Figure 1 plots consumption and net revenue by month for residential natural gas customers in Massachusetts in 2006. Natural gas consumption varies substantially throughout the year with per capita consumption increasing by a factor of five between summer and winter months as more natural gas is used for home heating. Net revenue follows a similar pattern, increasing substantially with per capita consumption and peaking in the winter. The variation in consumption during the course of the year traces the price schedule.

In addition to the monthly observations, figure 1 also plots fitted values from the following regression equation:

$$NR_t = \alpha_0 + \alpha_1 q_t + \epsilon_t, \quad t \in 1, 2, \dots, 12 \quad (1)$$

where monthly net revenue from residential sales per customer, NR_t , is regressed on monthly gas consumption per customer, q_t . The constant α_0 is the average amount paid in fixed fees while α_1 is the average per unit markup over the city gate price. The average per unit price (not plotted) is the city gate price plus α_1 . The price schedule indicates that revenues tend to be collected from the per unit price rather than the fixed fee. As a result, net revenue in winter months is many times higher than net revenue in summer months.

For our test of marginal cost pricing we estimate equation (1), allowing α_0 and α_1 to vary by

state, year, and customer class. The null hypothesis of marginal cost pricing is $\alpha_1 = 0$. Table 2 presents the main results of our test of marginal cost pricing. Panel A reports F-statistics by state over all years and customer classes, panel B reports F-statistics by year over all states and customer classes, and panel C reports F-statistics by customer class over all states and years. For all 50 states, all years and for all three customer classes, we reject marginal cost pricing with p -values less than 0.001. Overall, the tests provide strong evidence of departures from marginal cost pricing.⁹ Our conclusions do not change if we use the Platts city gate prices as our measure of marginal cost. Using this alternative measure of marginal cost, we still reject marginal cost pricing for all 48 states (Alaska and Hawaii not available), all years and all three customer classes.

Table 3 summarizes the per-unit markups borne by each customer class. On average, residential consumers paid a 45.1% per-unit markup over the city gate price, equivalent to a \$3.16 transportation fee per-unit. The per-unit markup for commercial customers is slightly lower, a 42.1% markup equivalent to a \$2.98 transportation fee per-unit. Markups are much lower for industrial customers - industrial customers pay a 1.5% markup over the city gate on average, equivalent to a \$0.20 transportation fee per-unit. Overall, the results imply an average markup across all customer classes of 36.4%. Using the Platts city gate prices, we find similar markups - we estimate that the average per-unit markup across all customer classes is 38.4%, equivalent to a \$2.71 per-unit markup. In the sections which follow we attempt to put these results in context, for example comparing our estimated markups to the increase that would be implied by proposed carbon legislation.

In addition to markups, table 3 reports the fraction of total revenues collected from each customer class. The results indicate that residential consumers were responsible for 74.9% of total revenues while receiving 54.4% of total core deliveries. In contrast, industrial customers were responsible for 0.5% of total revenues while receiving 18.1% of total core deliveries. Although the pattern of revenues is interesting, these results should be interpreted with caution because it is not clear how these collected revenues compare to marginal customer costs. For example, the residential market is characterized by a large number of customers, each consuming a relatively small amount of natural gas. For each customer the LDC must build and maintain an additional connection, purchase and maintain metering equipment, and process bills. Residential customers pay a large fraction of total revenue, but they also, therefore, impose a large fraction of total costs and with the available evidence it is difficult to make strong statements about the net burden borne by different

⁹In related work, Naughton (1982) tests the efficiency of price schedules for a sample of electric utilities in 1980. After estimating marginal costs using a translog cost function, Naughton finds that the per-unit prices faced by all customer classes exceed marginal costs.

customer classes.¹⁰

4.2 Total Deadweight Loss From Non-Marginal Cost Pricing

To evaluate the total deadweight loss from the observed departures from marginal cost pricing, we first estimate the elasticity of demand for each sector. We then calculate the deadweight loss associated with the current pricing schedules compared to marginal cost pricing.

For each customer class, we regress the log of monthly consumption per customer on the log of natural gas prices, state*month-of-year fixed effects, state*year fixed effects, and demand shifters. For the residential and commercial sectors which use natural gas for space heating, we include same-month heating and cooling degree days and interact heating and cooling degree days with prices to allow the elasticity to vary with temperature. For industrial customers, some of whom can switch between fuel oil and natural gas, we include the spot price of Brent crude oil. We instrument for natural gas prices using: heating and cooling degree days in all other states, and for residential and commercial demand, additionally use the Brent crude spot price. With state*month-of-year and state*year fixed effects, we estimate our coefficients off of deviations from mean seasonal patterns in each state. If long-run demand is more elastic, our estimate of the deadweight loss relative to marginal cost pricing would be conservative.

We present our demand elasticity estimates in table 4. We estimate that demand for natural gas in all three sectors is inelastic. The elasticity point estimates for residential, commercial and industrial users are -0.409 , -0.223 and -0.711 respectively. We estimate that the elasticity of residential customers is negatively correlated with heating degree days - residential consumers respond less to exogenous shifts in price during cold months. We estimate that a one standard deviation increase in monthly heating degree days (419 degree days) increases the residential elasticity point estimate by 0.115. In addition, we find that the cross-price elasticity of industrial demand with respect to the crude oil price is 0.347.

Table 5 reports deadweight loss generated by using existing pricing tariffs relative to marginal cost prices. We separately report deadweight loss for each customer class as well as block bootstrapped standard errors.¹¹ In total, we estimate that the existing price schedules create approx-

¹⁰See Stigler (1971) and Peltzman (1976) for discussion of the Stigler-Peltzman theory of regulation that argues that regulators act to transfer wealth between interest groups.

¹¹When calculating the deadweight loss, we assume that the number of customers using natural gas does not change. If firms can accurately estimate consumer willingness to pay based on observable and non-mutable characteristics (e.g. heating / non-heating residential), shifting to marginal cost pricing will create a welfare gain along the extensive margin as well. Consequently, our estimates likely understate the true deadweight loss.

imately 2.6 billion dollars in deadweight loss, relative to marginal cost pricing. In the United States total expenditure on natural gas in 2008 by core customers was \$92 billion so this represents approximately 3% of the total market.

These estimates provide a valuable preliminary assessment of the welfare consequences of the observed departures from marginal cost pricing. However, it is important to emphasize that the magnitude of the deadweight loss is sensitive to the elasticity of demand for natural gas. The estimates from Table 4 provide a starting point but there is some sampling variation in these estimates. Moreover, the relevant demand elasticity for these calculations is the long-run demand elasticity which is likely to be larger than the short-run elasticity because agents may employ additional margins of adjustment. For example, in the long-run, consumers may change heating and other equipment that uses natural gas. Because the stock of equipment turns over slowly, the full long-run impact of a price change may not be realized for many years and estimating such long-run effects using historical data is extremely challenging. In order to assess sensitivity, Table 5 reports deadweight loss estimates for two alternative sets of demand elasticities. The magnitude of the implied deadweight loss varies predictably with the choice of elasticities, but even under the most conservative assumption (-.20 for all customers), total deadweight loss exceeds \$1.2 billion annually.

5 Discussion of Possible Explanations

The results in the previous section provide strong evidence of departure from marginal cost pricing in the U.S. natural gas distribution market. In this section, we consider several possible explanations for the observed rate structure, all of which likely play a role in distorting prices away from the theoretical ideal. We then discuss the implications of the current rate structure for carbon policy and other public efforts aimed at addressing the external costs of energy consumption.

5.1 Profit Maximization by LDCs

One possible explanation for the current price schedules lies in the incentives created by rate-of-return regulation. As described in the previous section, the central idea behind rate-of-return regulation is that a firm's revenues must equal its costs so that economic profit is zero,

$$\sum_{i=1}^I Revenue(p_i) = sB + expenses.$$

In theory, s should be set equal to the firm's market rate of return on capital for a riskless asset r . In practice, however, s is imperfectly observed by regulators and face a difficult tradeoff. If they set s too low, the ability of the firm to raise capital can be threatened. If they set s too high, this yields positive profits for the firm. Trying to balance these two objectives and under pressure from regulated firms to increase s , the conventional wisdom is that in practice s typically exceeds r .¹²

When $s > r$, the regulated firm has incentive to maximize the rate base B . As pointed out by Sherman and Visscher (1982), the price schedule that best allows the firm to increase B depends on whether adding customers or increasing output requires marginally the most capital. For natural gas distribution, capital depends most importantly on the number of customers. More customers means more miles of network, more connections, more metering equipment, etc. Although a large number of potential rate structures p_i satisfy the zero profit condition, from the regulated firm's perspective the optimal rate structure is one with very low monthly fees that will induce as many customers as possible to enter the market.¹³ Of course, lower monthly fees also mean higher prices per unit. However, decreased consumption along the intensive margin is not costly from the regulated firm's perspective because the rate base B does not depend on the level of natural gas consumption per customer. In short, under traditional rate-of-return regulation a regulated firm attempts to maximize B , and this creates incentive for firms to lobby regulators for low fixed fees.

In adjusting per unit fees and connection fees, the LDC faces a tradeoff between small and large customers. Small customers are sensitive to fixed fees while large customers are sensitive to the price per unit. Consider for example, a decrease in the fixed fee that is offset by an increase in the price per unit. Such a change attracts small customers while potentially leading some large consumers to switch to other energy sources. Whether or not such a change leads to a net increase or decrease in the number of customers depends on the distribution of customers of different sizes and the ease with which they can substitute across fuels. For the rate-base maximizing explanation to make sense, it must be the case that the current price schedules with low connection fees tend to increase the customer base relative to alternative schedules. There would seem to be some support for this. Particularly in the commercial and residential sectors there are a large number of smaller customers who may indeed be sensitive to the connection fee. Moreover, there tend to be fewer

¹²See, e.g. Averch and Johnson (1962), Baumol and Klevorick (1970), and Joskow (1974).

¹³These incentives could also help explain the fact that monthly fees sometimes vary within customer class. For example, some companies charge monthly fees for industrial customers that vary by historical consumption levels and some companies charge different monthly fees for residential customers depending on whether or they use natural gas for heating. This price discrimination could be seen as a mechanism for inducing as many customers as possible into the market.

large customers and the largest customers e.g. non-core industrial and commercial customers are typically able to negotiate alternative rate structures rather than switch to other energy sources.

From an efficiency standpoint, the important question in this context is how existing fixed fees compare to marginal connection costs. To add an additional customer requires connecting the customer to the central distribution network. This connection cost depends on the distance from the customer to the central network. In addition, LDCs incur costs installing and maintaining meters, processing bills, providing customer service, etc. Much of these additional costs should be considered marginal connection costs. Our study reveals low fixed fees across states and customer classes and near-zero fixed fees in many states and customer classes. Efficiency could be enhanced by increasing these fixed fees up to the level of marginal customer costs.

5.2 Distributional Considerations

Distributional considerations provide an alternative and complementary explanation for the observed rate structure. With low connection fees the existing rates imply that within customer classes high-demand customers pay a large share of fixed costs. Where monthly fees are exactly zero, for example, a customer consuming 100 McF annually pays twice as much as a customer consuming 50 McF despite the fact that the cost of providing distribution service to these two customers is nearly identical. This structure is likely to have positive distributional consequences. For example, to the extent that high-income households own large homes and consume high levels of natural gas, they will also pay a large share of total costs. This distributional argument is highlighted in a recent rate case for Bay State Gas before the Massachusetts Department of Telecommunications and Energy (*emphasis added*).

The Attorney General also takes issue with the Company's proposed residential delivery rates (id. at 116-117). While the Company proposed block rates for the residential rate classes, the Attorney General requests that the Company provide a flat rate design (i.e., no block charges) for the residential rate classes (id. at 117). The Attorney General argues that a flat rate design for the residential rate classes not only would simplify rate design but would also *provide lower bill impacts for all but those customers with higher than average use*.¹⁴

¹⁴Massachusetts Department of Telecommunications and Energy, DTE 05-27, p. 325

These distributional concerns make it politically difficult to implement rate changes that would increase fixed fees. Although state and federal programs exist aimed at providing assistance to low-income households with energy bills, there are concerns that these programs may not do enough for vulnerable populations.¹⁵ More broadly, the fixed fees are very salient to consumer protection groups and they are correctly perceived as substantially impacting energy bills for low-income groups and small businesses.

5.3 Environmental Externalities

Environmental externalities provide a third possible explanation for setting the per-unit price above the marginal commodity cost. Natural gas combustion releases .09 pounds of nitrogen oxides and .007 pounds of particulates per McF and one could imagine implementing a Pigouvian tax equal to the marginal damages from these emissions.¹⁶ However, the available estimates of marginal damages imply that the price increases implied by such a tax would be considerably smaller than the existing markups in the market. Using estimates from Muller and Mendelsohn (forthcoming), the external costs of emissions of nitrogen oxides and particulates are less than 3 cents per McF, equivalent to a markup over average residential prices of about one fifth of one percent. Of course, marginal damages from local pollutants depend on the proximity between the location of emissions and population centers. However, even the 99% percentile estimates from Muller and Mendelsohn imply markups of less than 1% over average residential prices.¹⁷

Although local pollutants are important, given recent increased attention to the issue of climate change it is also important to consider the implications of current pricing schedules for carbon emissions. Section 4 showed that different customer classes face substantially different markups

¹⁵The largest such program, the Low Income Home Energy Assistance Program (LIHEAP) has been in operation since 1982 and operates in all 50 states with a \$4.5 billion dollar budget in 2009. Eligible household must meet income requirements and typically assistance is awarded on a first come-first served basis.

¹⁶U.S. Department of Energy, Energy Information Administration, ‘Natural Gas 1998: Issues and Trends’, DOE/EIA-0560(1998), released April 1999, Chapter 2: Natural Gas and the Environment, Table 2. See also U.S. Department of Energy, Energy Information Administration, ‘Annual Energy Review’, DOE/EIA-0384(2007), released June 2008, Table 12.7a. Natural gas is the cleanest of all major fossil fuels. Per unit of energy, natural gas combustion releases 80% less nitrogen oxides, 90% less particulates, and over 99% less sulfur dioxide and mercury than oil combustion.

¹⁷Muller and Mendelsohn (forthcoming), use an integrated assessment model to track and value emissions from 10,000 point and aggregated non-point sources in the United States. Average marginal damages from Table 1 are \$1.61 per pound of particulates (PM_{2.5}) and \$.13 per pound of nitrogen oxides. The 99th percentile of marginal damages is \$6.20 per pound of particulates (PM_{2.5}) and \$.55 per pound of nitrogen oxides. Alternative, and somewhat larger estimates of the marginal damages of nitrogen oxide emissions come from Muller, Tong, and Mendelsohn (2009) using the Community Multi-scale Air Quality model (CMAQ) rather than the reduced-form Air Pollution Emission Experiments and Policy (APEEP) model used in Muller and Mendelsohn (forthcoming). With CMAQ, marginal damages from ground-level nitrogen oxide emissions from nine locations in and around Atlanta (Table 1) average \$.27 per pound with a maximum of \$.55.

above marginal price that ranges from 1.5% for core industrial customers to 45.1% for residential customers. For industrial customers this is equivalent to the markup that would be implied by a carbon tax of \$13 per metric ton of carbon while for residential customers this is equivalent to a carbon tax of \$212 per metric ton. Interestingly, these markups straddle markups implied by the range of carbon taxes envisioned by most economists. For example, Nordhaus (2008) adopts a carbon tax of \$35 per metric ton and Metcalf (2007) proposes a tax of \$55 per metric ton. Regardless of ones views on the marginal external costs of carbon emissions, it is critical that carbon policy take into account pre-existing distortions in the market. Using \$35 per metric ton of carbon, for example, the current after-tax price of natural gas for residential and commercial customers already exceeds marginal social costs.¹⁸ In this case, natural gas consumption levels are already too low, and adding a tax to this market would further exacerbate the deadweight losses described in table 5. In standard externality theory, a tax equal to marginal damages equates private marginal benefits with social marginal costs, leading to the efficient level of output. This first-best solution assumes, however, that in the absence of the tax, equilibrium prices are equal to private marginal cost as they are, for example, in a perfectly competitive market. This is a case where the Pigouvian tax not only fails to bring about the efficient level of output, but may actually lead to a welfare loss.

6 Ownership Structure and Efficiency

There are several available approaches for addressing these departures from marginal cost pricing. There are many alternative rate structures which could improve efficiency while allowing LDCs to recoup their investments. In the conclusion we discuss rate “levelization”, which would increase fixed fees while decreasing per unit prices.

An alternative approach for lowering per-unit prices is public provision. Energy utilities in the United States operate under one of two types of institutional arrangements: (1) privately-owned companies regulated by state public utility commissions, and (2) publicly-owned or “municipally-owned” companies that are directly under public control. In both cases, the public sector controls rate setting. However, unlike privately-owned companies which must recoup fixed costs from end users of natural gas, municipally-owned companies can recoup fixed costs through government subsidies, thereby shifting the burden of fixed costs from natural gas consumers to taxpayers.

¹⁸In related work, Buchanan (1969), Barnett (1980), and Oates and Strassman (1984) consider Pigouvian taxes in the context of an unregulated monopoly.

Consequently, a municipally-owned LDC may offer a price schedule with lower per-unit markups. Still, as we discuss in this section the welfare effects of public provision are ambiguous because subsidies must be financed through distortionary taxes.

Municipal ownership is common in natural gas distribution. In 2007, approximately two-thirds of LDCs were municipally-owned (848 out of a total of 1,229). On average, municipally-owned LDCs are much smaller than investor-owned LDCs. In total, municipally-owned LDCs delivered only eight percent of the natural gas to end-users in 2007. Despite differences in mean deliveries, the size distributions of municipally-owned and investor-owned LDCs overlap substantially. Approximately 45 percent of municipal utilities and 34 percent of investor-owned utilities deliver between 100 million cubic feet of gas a year and 10 billion cubic feet of gas per year. Municipal utilities and investor-owned utilities are comparable on other observable dimensions. For the average municipally-owned distribution company, 41 percent, 25 percent and 33 percent of deliveries are made to residential, commercial and industrial customers. In comparison, 42 percent, 26 percent and 30 percent of deliveries of investor-owned utilities go to residential, commercial and industrial customers.

To estimate the proportion of municipal utility fixed costs borne by taxpayers, we calculate annual net revenues for each distribution company using the utility-level data from 1997 to 2007. In total, we observe 9,426 company-years of municipal data and 3,755 company-years of investor-owned data. We compare the net revenues earned by comparably-sized municipally-owned and investor-owned distribution companies. Table 6 presents the results from regressing annual net revenues for each firm on total deliveries (as a proxy for firm size), the proportion of deliveries made to industrial or electric customers (to account for differences in the composition of end users), population density, and a dummy variable corresponding to whether the distribution company is municipally-owned. In each specification, we include state fixed effects and year fixed effects. Controlling for size and customer composition, we expect municipal utilities and investor-owned utilities to have similar fixed costs. Absent the ability of the government to fiscally subsidize a municipal utility, the firms should require similar net revenues. Specifications (1) and (2) include all firms, while specifications (3) and (4) restrict the sample to the portion of the firm size distribution where substantial overlap between municipally-owned and investor-owned LDCs exists - between 100 million and 5 billion cubic feet of delivered gas per year. Restricting the sample to mid-sized distribution companies does not substantially affect the results. In all four regressions we estimate a positive coefficient on annual deliveries between 0.805 and 0.950 - in all cases, the estimates are statistically distinguishable

from 1 - consistent with a natural monopoly exhibiting economies of scale. We estimate that a 10 percentage point increase in the share of deliveries to large (industrial/electric) customers is associated with a 12-13 percent reduction in net revenues. Finally, we estimate that, conditional on observables, municipally-owned distribution companies collect approximately 25 to 30 percent less net revenues through their service rates than investor-owned utilities. This is consistent with substantial direct subsidies to municipally-owned LDCs that would allow these companies to charge lower marginal prices.¹⁹

The overall welfare impact of direct subsidies depends, therefore, on the marginal cost of public funds. While subsidies increase the welfare of natural gas users, these gains are offset by tax distortions in other parts of the economy. As a thought exercise, we calculate the threshold cost of public funds which lead a 25 percent subsidy of fixed costs to be welfare neutral. We estimate that a 25 percent subsidy of the per unit transportation fee requires \$5.85 billion per year to cover lost revenues and is associated with a welfare gain of \$733 million to natural gas users. Consequently, the welfare-neutral threshold cost of public funds is roughly 12 cents per dollar. If a jurisdiction can collect taxes which introduce less than 12 cents of deadweight loss per dollar of revenue generated (and the cost of public versus private provision are similar), public subsidization of the fixed costs of operation may improve welfare if used to reduce per-unit markups.

7 Concluding Remarks

Our analysis of the U.S. natural gas distribution market supports the following conclusions. First, we strongly reject marginal cost pricing. This result holds individually and jointly for all 50 states and all customer classes. Second, departures from marginal cost pricing are most severe for residential and commercial customers with markups averaging 45% and 42%. Third, for conservative estimates of the price elasticity of demand, these distortions impose large aggregate welfare losses compared to marginal cost pricing. In short, the current system with low fixed fees and high per unit prices implies that there are too many natural gas customers, each consuming too little natural gas.

The broader lesson from these findings is that policymakers ought to take careful account of

¹⁹An alternative explanation is that regulators allow investor-owned or privately-owned utilities to earn substantially higher profit than those earned by a municipally-owned LDC. To check, we examined the 2007 annual reports of the six largest municipally-owned LDCs. In 2007, the six municipally-owned LDCs examined received direct and indirect subsidies. Subsidies took the form of government grants to cover operation, repairs and construction, access to subsidized government and cooperative natural gas supplies, and the ability to issue tax-exempt government bonds and commercial paper.

pre-existing distortions due to regulated natural monopolies when considering carbon policies and other policies aimed at addressing externalities. Our study has shown that these distortions are large enough to be economically significant and that existing markups may be even be larger than the price increases that would be implied by proposed carbon policies. If this is the case, then public intervention in these markets should proceed with extreme caution because a carbon tax or cap-and-trade program would further reduce consumption below the socially efficient level, exacerbating the welfare losses described here.

The other market for which our results are immediately applicable is electricity. Electricity distribution is also a clear natural monopoly, and electricity LDCs are regulated using similar rate-of-return methods. Departures from marginal cost pricing may actually be more pronounced in electricity markets because of the widespread use of increasing block tariffs. On the other hand, some forms of electricity production, and in particular, coal, are associated with considerably larger external costs than natural gas.

Of the available approaches for addressing these departures from marginal cost pricing, the most natural approach would be to have regulators work with LDCs to “levelize” rate structures, lowering the price charged per unit. Fixed fees could then be increased from their currently very low level to recoup lost revenue. There is some precedent for this. For example, in May 2008 a new rate structure was approved for Duke Energy Ohio in which the monthly fixed delivery charge increased from \$4.50 to \$10.00 with an offsetting reduction in marginal prices. The Public Utilities Commission of Ohio (PUCO) argued that the new “levelized” rate structure is more equitable, “making sure that each customer pays only their share of the costs Duke must cover to deliver gas to their home.” According to PUCO, the costs of natural gas distribution including installing and maintaining pipelines, reading gas meters, processing bills, and taking customer service calls is the same “whether a customer uses a little natural gas each month, or a lot.”

Such a transition would have distributional consequences. With the current system a large share of total fixed costs are borne by high-volume customers. Politically it will be important for “levelization” to be accompanied by targeted assistance for low-income households. Again, Duke Energy Ohio provides precedent. Along with the rate changes, Duke introduced an income payment plan that reduces fixed fees for low-income customers. Although regulators are typically resistant to allowing widespread differences in rates across customers within customer classes, there is broad experience with such needs-based programs and they can be implemented at relatively low cost.

References

- [1] Averch, H. and L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, 1962, 1052-1069.
- [2] Baumol, William J. and D. F. Bradford. "Optimal Departures from Marginal Cost Pricing," *American Economic Review*, 1970, 265-283.
- [3] Baumol, W. J. and A.K. Klevorick, "Input Choices and Rate-of-Return Regulation: An Overview of the Discussion," *Bell Journal of Economics and Management Science*, 1970, 1, 162-190.
- [4] Barnett, A.H., "A Pigouvian Tax Rule Under Monopoly," *American Economic Review*, 1980, 70, 1037-1041.
- [5] Boiteux, Marcel. "Sur la gestion des Monopoles Publics astreints a l'equilibre budgetaire," *Econometrica*, 1956, 24(1), 22-40.
- [6] Borenstein, Severin, "Equity Effects of Increasing-Block Electricity Pricing," Center for the Study of Energy Markets Working Paper 180, University of California Energy Institute, November 2008.
- [7] Borenstein, Severin, Meghan Busse, and Ryan Kellogg, "Principal-Agent Incentives, Excess Caution, and Market Inefficiency: Evidence from Utility Regulation" NBER Working Paper 13679, 2009.
- [8] Buchanan, James M, "External Diseconomies, Corrective Taxes, and Market Structure," *American Economic Review*, 1969, 59, 174-177.
- [9] Coase, R.H., "The Marginal Cost Controversy." *Economica*, 1946, 13(51), 169-182.
- [10] Davis, Lucas and Lutz Kilian, "The Allocative Cost of Price Ceilings in the U.S. Residential Market for Natural Gas," 2008, working paper.
- [11] Feldstein, M., "Equity and Efficiency in Public Sector Pricing: The Optimal Two-Part Tariff," *Quarterly Journal of Economics*, Vol. 86, No. 2 (May, 1972), pp. 175-187.
- [12] Friedman, L.S., "Energy Utility Pricing and Customer Response: The Recent Record in California." Regulatory Choices Ed. Richard J. Gilbert. Berkeley: University of California Press, 1991, 10-62.
- [13] Kahn, Edward. *Electric Utility Planning and Regulation*, Washington D.C.: American Council for an Energy-Efficient Economy, 2nd Edition, 1994.
- [14] Knittel, Christopher R. "Market Structure and the Pricing of Electricity and Natural Gas," *Journal of Industrial Economics*, 2003, 60(2), 167-191.
- [15] Klein, C.C. and G.H. Sweeney. "Regulator Preferences and Utility Prices: Evidence from Natural Gas Distribution Utilities," *Energy Economics*, 1999, 21, 1-15.
- [16] Joskow, P. "Inflation and Environmental Concern: Change in the Process of Public Utility Price Regulation," *Journal of Law and Economics*, 1974, 2, 291-327.

- [17] Metcalf, Gilbert E., "A Proposal for a U.S. Carbon Tax Swap," *Brookings Institution Discussion Paper*, 2007-12, October 2007.
- [18] Muller, Nicholas, and Mendelsohn, Robert. "Efficient Pollution Regulation: Getting the Prices Right" *American Economic Review*, forthcoming.
- [19] Muller, Nicholas, Daniel Tong, and Robert Mendelsohn "Regulating NOx and SO2 Emissions in Atlanta," *The B.E. Journal of Economic Analysis and Policy*, 2009, 9(2), Article 3.
- [20] Naughton, Michael C., "The Efficiency and Equity Consequences of Two-Part Tariffs in Electricity Pricing," *Review of Economics and Statistics*, 1982, p. 406-414.
- [21] Nelson, Randy A. "An Empirical Test of the Ramsey Theory and Stigler-Peltzman Theory of Public Utility Pricing," *Economic Inquiry*, 1982, 20(2): 277-290.
- [22] Ng, Yew-Kwang, and Mendel Weisser. "Optimal Pricing with a Budget Constraint-The Case of the Two-part Tariff," *Review of Economic Studies*, 1974, 41(3): 337-345.
- [23] Nordhaus, William "A Review of the Stern Review on the Economics of Global Warming," *Journal of Economic Literature*, 2007, 45(3), 686-702.
- [24] Oates, Wallace E. and Diana L. Strassman. "Effluent Fees and Market Structure," *Journal of Public Economics*, 1984, 24, 29-46.
- [25] Peltzman, Sam. "Toward a More General Theory of Regulation," *Journal of Law and Economics*, 1976, 19: 211-240.
- [26] Ramsey, F. "A Contribution to the Theory of Taxation," *Economic Journal*, 1927, 47-61.
- [27] Stigler, George J. "The Theory of Economics Regulation," *Bell Journal of Economics*, 1971, 2: 3-21.
- [28] Schmalensee, Richard "Monopolistic Two-Part Pricing Arrangements," *Bell Journal of Economics*, 1981, 12: 445-460.
- [29] Sherman, Roger, and Michael Visscher "Rate-of-Return Regulation and Two-Part Tariffs," *Quarterly Journal of Economics*, 1982, 96: 27-42.
- [30] Viscusi, K., J. Harrington Jr. and J. Vernon. "Economics of Regulation and Antitrust, 4th Ed.," MIT Press, 2005.

Figure 1: Residential Natural Gas Price Schedule For Massachusetts for 2006

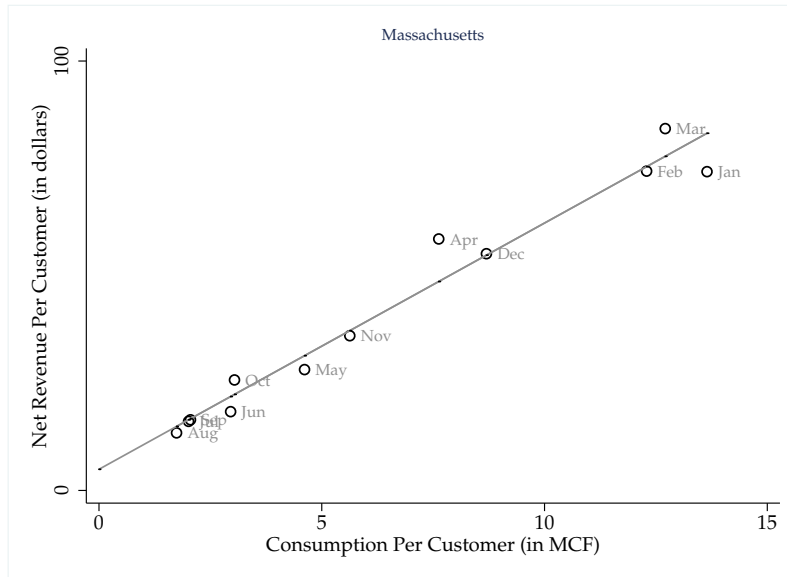


Figure 2: Residential Natural Gas Price Schedules for 2006, By State

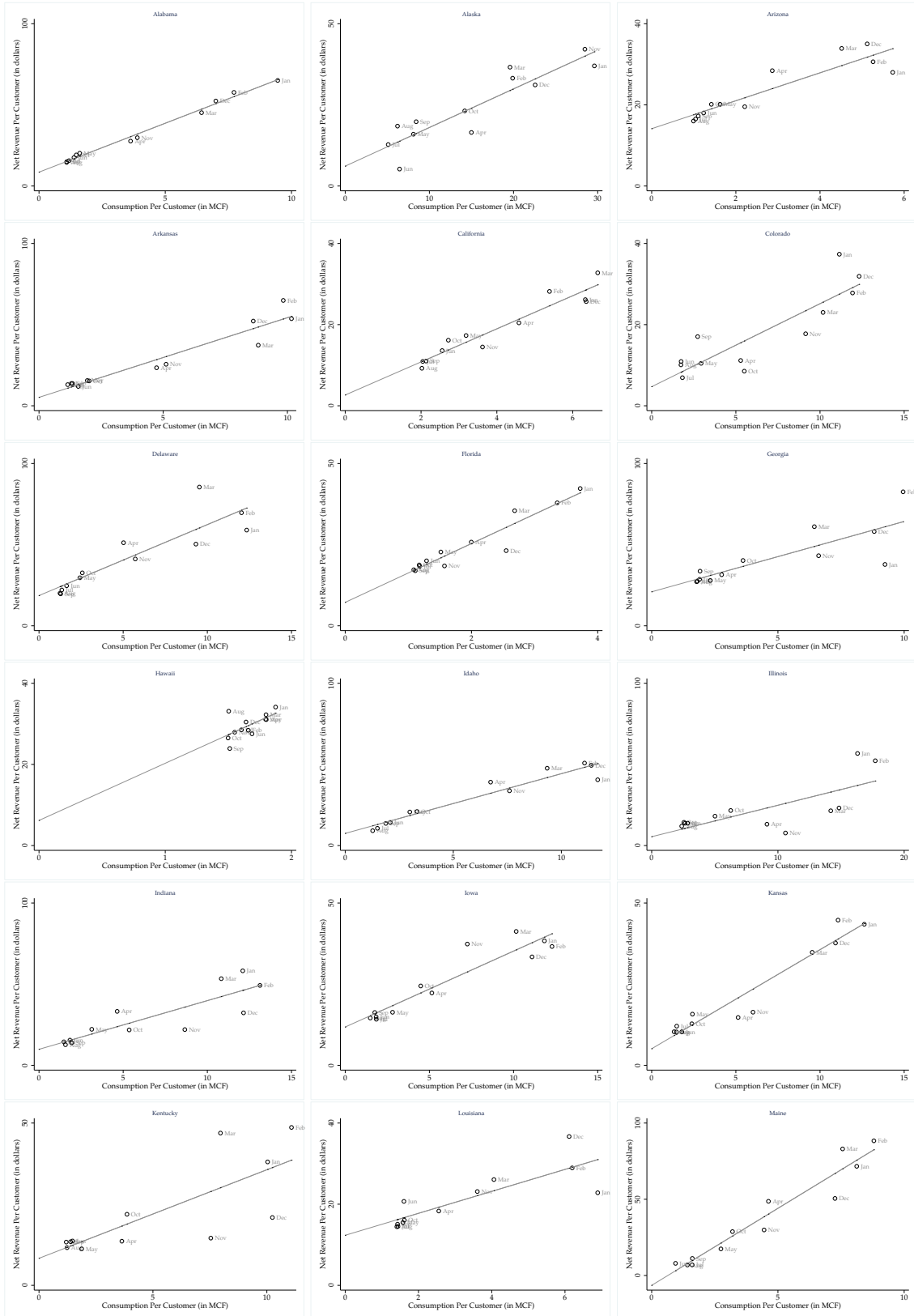


Figure 3: Residential Natural Gas Price Schedules for 2006, By State (continued)

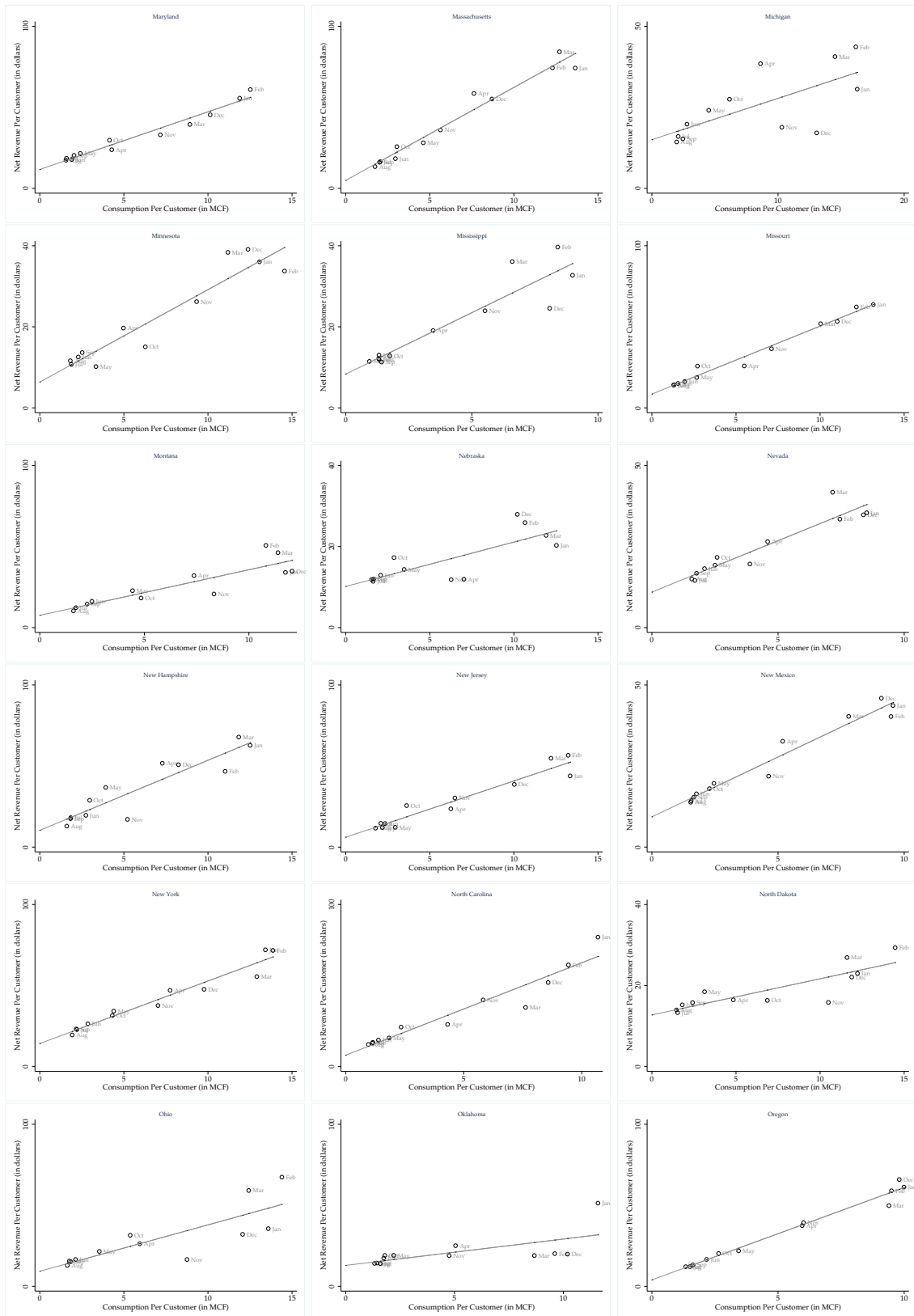


Figure 4: Residential Natural Gas Price Schedules for 2006, By State (continued)

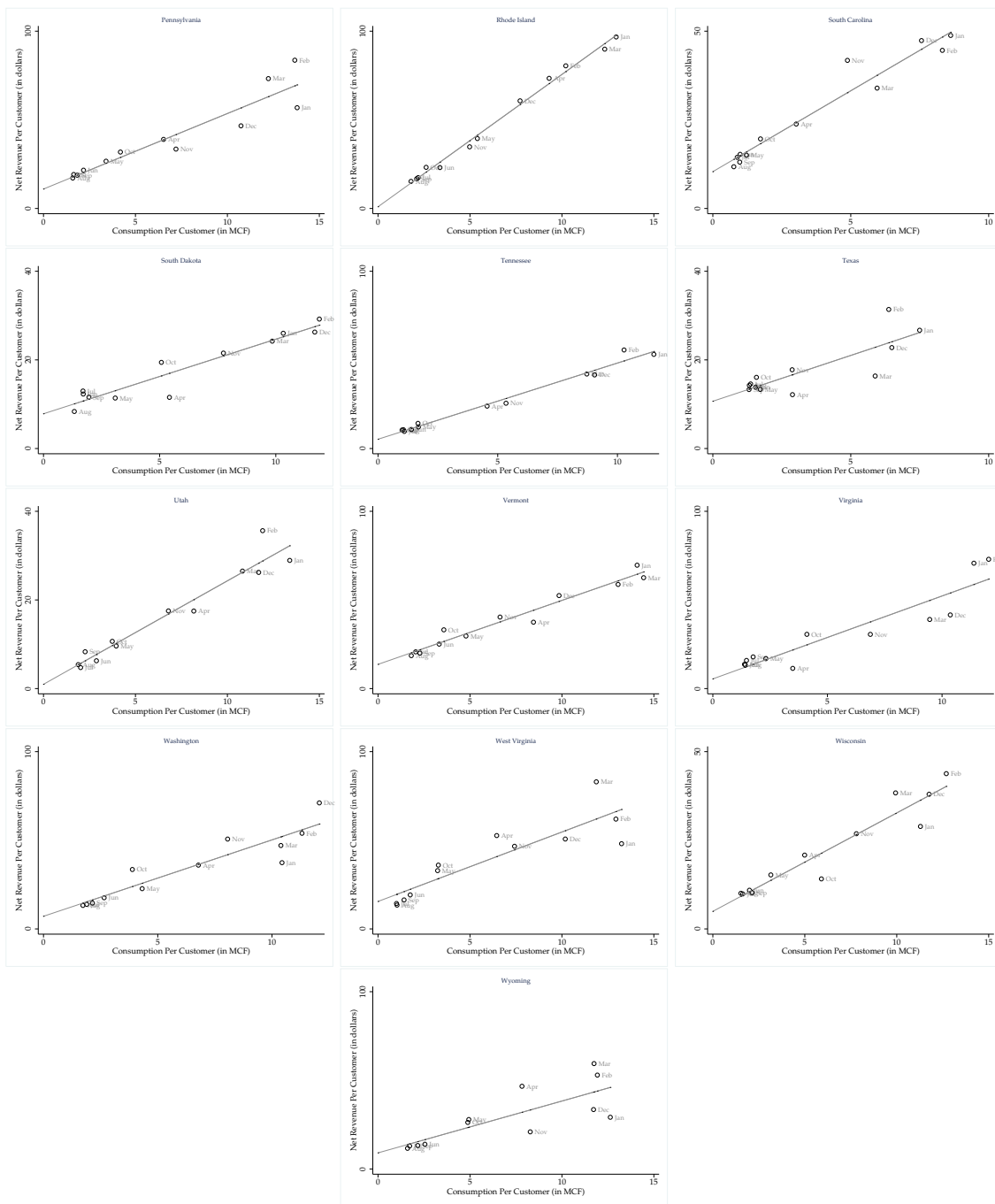


Table 1: Summary Statistics, by Sector

Variable	Obs	Mean	Std. Dev	Min	Max
Monthly Consumption (millions cubic feet)					
Residential	12,172	7,806	12,900	12	104,000
Commercial	12,139	4,854	6,454	37	51,600
Industrial	4,671	11,600	22,200	0	198,000
Electric	4,527	10,100	21,500	0	193,000
Monthly Consumption Per Customer (Mcf per Customer)					
Residential	11,623	7.00	5.55	0.54	31.30
Commercial	11,608	52.31	34.59	2.17	284.31
Industrial	4,150	50478	159474	14.27	1167727
Average Delivered Price (\$2008 per McF)					
Residential	12,171	11.45	4.63	3.00	57.38
Commercial	12,160	8.84	3.48	2.11	74.57
Industrial	4,684	8.82	3.06	1.44	32.71
Electric	2,657	7.44	2.54	1.34	25.83
City Gate Price (\$2008 per McF)	12,169	5.78	2.66	0.40	37.74
City Gate Price from Platts (\$2008 per McF)	10,584	4.42	2.17	1.06	25.61
Brent Spot Price (\$2008 per bbl)	11,628	33.42	16.05	12.20	92.41
Heating Degree Days	11,040	431.1	419.4	0	2109

Note: Consumption and price data for residential and commercial customers begin in 1989. Consumption and price data for industrial customers begin in 2001. Customer counts are unavailable for 2008. Platts Spot Prices are unavailable for 1989, 2008 and for the states of Alaska and Hawaii.

Table 2: A Test of Marginal Cost Pricing in U.S. Natural Gas Distribution, 1989-2008

Panel A. By State					
	F Statistic	(<i>p</i> -value)		F Statistic	(<i>p</i> -value)
Alabama	224.6	(<.001)	Montana	21.0	(<.001)
Alaska	66.8	(<.001)	Nebraska	31.0	(<.001)
Arizona	72.2	(<.001)	Nevada	32.0	(<.001)
Arkansas	83.0	(<.001)	New Hampshire	59.8	(<.001)
California	56.2	(<.001)	New Jersey	46.6	(<.001)
Colorado	13.3	(<.001)	New Mexico	30.0	(<.001)
Connecticut	162.6	(<.001)	New York	54.9	(<.001)
Delaware	41.0	(<.001)	North Carolina	95.8	(<.001)
Florida	19.6	(<.001)	North Dakota	20.8	(<.001)
Georgia	17.4	(<.001)	Ohio	32.3	(<.001)
Hawaii	4.8	(<.001)	Oklahoma	30.9	(<.001)
Idaho	66.7	(<.001)	Oregon	170.8	(<.001)
Illinois	22.5	(<.001)	Pennsylvania	157.7	(<.001)
Indiana	38.2	(<.001)	Rhode Island	112.1	(<.001)
Iowa	88.4	(<.001)	South Carolina	85.9	(<.001)
Kansas	53.7	(<.001)	South Dakota	48.7	(<.001)
Kentucky	36.5	(<.001)	Tennessee	50.9	(<.001)
Louisiana	20.7	(<.001)	Texas	11.1	(<.001)
Maine	33.3	(<.001)	Utah	59.0	(<.001)
Maryland	109.5	(<.001)	Vermont	179.1	(<.001)
Massachusetts	96.1	(<.001)	Virginia	66.8	(<.001)
Michigan	42.4	(<.001)	Washington	25.6	(<.001)
Minnesota	76.4	(<.001)	West Virginia	62.9	(<.001)
Mississippi	60.0	(<.001)	Wisconsin	418.9	(<.001)
Missouri	63.1	(<.001)	Wyoming	10.5	(<.001)
Panel B. By Year					
	F Statistic	(<i>p</i> -value)		F Statistic	(<i>p</i> -value)
Year 1989	97.9	(<.001)	Year 1990	175.5	(<.001)
Year 1991	216.1	(<.001)	Year 1992	161.6	(<.001)
Year 1993	182.5	(<.001)	Year 1994	246.5	(<.001)
Year 1995	235.5	(<.001)	Year 1996	71.7	(<.001)
Year 1997	16.1	(<.001)	Year 1998	127.5	(<.001)
Year 1999	73.7	(<.001)	Year 2000	23.3	(<.001)
Year 2001	5.7	(<.001)	Year 2002	44.2	(<.001)
Year 2003	25.7	(<.001)	Year 2004	101.1	(<.001)
Year 2005	69.8	(<.001)	Year 2006	41.6	(<.001)
Year 2007	72.4	(<.001)	Year 2008	48.1	(<.001)
Panel C. By Customer Class					
	F Statistic	(<i>p</i> -value)		F Statistic	(<i>p</i> -value)
All States, Residential Customers Only				54.6	(<.001)
All States, Commercial Customers Only				35.0	(<.001)
All States, Industrial Customers Only				1.7	(<.001)
All States, Pooled				6.3	(<.001)

Note: The F-statistic for the tests by state are joint tests over all years and customer classes in a particular state. For residential and commercial customers, data are available for all states for the period 1989-2008. Industrial utility customers data are available from 2001, though observations are missing for some states and years. We dropped data for a particular state-class-year if more than six monthly observations are missing. Thus typically for a given state there are a total of between 50 and 55 total estimates of α_1 and the F-statistic is a joint test that α_1 is equal to zero for all customer classes and years. The F-statistic for the tests by customer class are joint tests over all states and years. Thus there are 1020 estimates of α_1 for the residential tests, 1018 estimates of alpha for the commercial tests and 399 estimates of α_1 for the industrial test. The pooled test is a joint test over 2437 α_1 parameters. All F-statistics cluster by state.

Table 3: Average Deliveries, Revenues, and Markups By Customer Class

	Fraction of Total Core LDC Deliveries	Fraction of Total LDC Net Revenues	Per-Unit Markup Over City Gate Price	
			Percent	Levels (per McF)
Residential Customers	54.4%	74.9%	45.1% (0.7%)	\$3.16 (0.04)
Commercial Customers	27.5%	24.7%	42.1% (0.7%)	\$2.98 (0.05)
Industrial Customers	18.1%	0.5%	1.5% (4.1%)	\$0.20 (0.27)
All Customers, Pooled	100.0%	100.0%	36.4% (0.8%)	\$2.57 (\$0.05)

Note: The table reports averages across all available states for 2002-2007 for which data is available for all sectors, weighted by natural gas consumption in each state. Pooled markups are weighted by natural gas consumption for each customer class. Per-unit markups are normalized to year 2007 dollars. Deliveries to electric generators and non-core industrial and commercial customers excluded. Standard errors in parentheses are block bootstrap by state.

Table 4: Demand Elasticity, by Customer Class

	Residential	Commercial	Industrial
Log(Delivered Price)	-0.409*** (0.122)	-0.223** (0.104)	-0.711** (0.298)
Log(Price)*HDD	0.275*** (0.038)	0.043 (0.049)	
Log(Price)*CDD	0.080 (0.067)	-0.046 (0.130)	
Log(Brent Crude Price)			0.347** (0.153)
Heating Degree Days (000s)	0.163* (0.091)	0.611*** (0.110)	
Cooling Degree Days (000s)	-0.479** (0.203)	-0.022 (0.283)	
Observations	10935	10924	3984
R^2	0.986	0.972	0.993

Note: The first-stage F-statistics on the excluded instruments for delivered natural gas prices to residential, commercial and industrial customers and 5.7, 7.2 and 22.6, all of which are significant at a p-value less than 0.001. The first-stage F-statistics on the excluded instruments for the residential and commercial interaction terms with heating and cooling degree days are 145.2, 253.5, 119.7 and 350.9. Residential and commercial elasticities are estimated using data from 1989 to 2007. Industrial elasticities are estimated using data from 2001 to 2007. All specifications include state*month-of-year and state*year fixed effects. Standard Errors clustered by state. *, **, *** denote significance at the 90%, 95%, and 99% level, respectively.

Table 5: Estimates of Annual Deadweight Loss (in Millions), U.S. Natural Gas Distribution Market 2001-2008

	Using Elasticities From Table 4	Setting All Elasticities = -0.2	Setting All Elasticities = -0.5
Residential Customers	1,002 (399)	707 (13)	1,922 (37)
Commercial Customers	387 (162)	345 (8)	936 (22)
Industrial Customers	1,210 (602)	230 (21)	647 (76)
All Customers, Pooled	2,599 (749)	1,282 (25)	3,505 (85)

Note: To calculate total DWL for all customers, we limit the analysis to years with a balanced panel, 2001 to 2008. Including 1989 to 2000 for residential and commercial DWL calculations does not qualitatively change the annual deadweight loss relative to marginal cost pricing. Standard errors are block bootstrapped by state with 100 replications. For each bootstrap sample in column (1), we re-estimate the price schedules and elasticities. For each bootstrap sample in columns (2) and (3), we re-estimate the price schedules and take the elasticity as given.

Table 6: Net Revenues of Municipally- and Investor-Owned LDCs

	(1)	(2)	(3)	(4)
Log(Annual Deliveries)	0.873*** (0.009)	0.950*** (0.009)	0.805*** (0.026)	0.903*** (0.024)
Municipally-Owned	-0.314*** (0.052)	-0.265*** (0.045)	-0.310*** (0.074)	-0.251*** (0.066)
Share of Deliveries to Industrial Customers		-1.347*** (0.081)		-1.200*** (0.106)
Population Density		0.313 (0.389)		1.024* (0.614)
Full Sample	X	X		
Mid-sized Firms Only			X	X
Observations	11289	11289	4965	4965
R-squared	0.90	0.91	0.67	0.70

Note: All specifications include state fixed effects and year fixed effects. Standard Errors clustered by company. *, **, *** denote significance at the 90%, 95%, and 99% level, respectively.