PRE-FILED DIRECT TESTIMONY

OF

JAMES D. SIMPSON

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James D. Simpson. I am a Vice President with Concentric Energy Advisors ("Concentric"), 293 Boston Post Road West, Marlborough, Massachusetts 01752. My professional qualifications and experience are provided in Attachment NG-JDS-1 of this testimony.

Q. FOR WHAT PURPOSE HAS NATIONAL GRID RI - GAS ("NATIONAL GRID" OR THE "COMPANY") RETAINED CONCENTRIC?

A. Concentric has been retained to advise the Company on the development of a decoupling mechanism.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I will explain the mechanics of the Company's proposed decoupling mechanism. I also will describe my analysis of the reduction in revenues that the Company has been experiencing as a result of reduced use by customer. Finally, I will briefly discuss some of the rate activity in other jurisdictions where decoupling mechanisms have been implemented.

Q. PLEASE PROVIDE A LIST OF THE ATTACHMENTS THAT YOU HAVE PREPARED IN SUPPORT OF THIS TESTIMONY.

A. The table below lists the attachments that I have prepared in support of my testimony.

Attachment	
NG-JDS-1	James D. Simpson Qualifications and Experience
NG-JDS-2	Draft Energy Efficiency Awareness Form
NG-JDS-3	Summary of Gas LDC Decoupling Mechanism Proposals
NG-JDS-4	Residential Heat Rolling 12 Month NUPC Graph: June 2004 - Dec 2007
NG-JDS-5	Commercial And Industrial Small Rolling 12 Month NUPC Graph: June 2004 - Dec 2007
NG-JDS-6	Commercial And Industrial Medium Rolling 12 Month NUPC Graph: June 2004 - Dec 2007
NG-JDS-7	Efficiency Standards
NG-JDS-8	Residential Heat Price / Use per Customer Analysis
NG-JDS-9	Commercial and Industrial Small Price / Use per Customer Analysis
NG-JDS-10	Commercial and Industrial Medium Price / Use per Customer Analysis
NG-JDS-11	AGA 2003 Report
NG-JDS-12	AGA 2007 Elasticity Study

II. SPECIFICS OF NATIONAL GRID'S RATE DESIGN PROPOSAL

A. INTRODUCTION

Q. PLEASE DESCRIBE THE COMPANY'S REVENUE DECOUPLING PROPOSALS.

A. National Grid is proposing to (a) increase customer charges for all firm rate classes; (b) increase C&I demand charges and (c) implement a revenue-per-customer ("RPC") decoupling mechanism for all firm rate classes. As described in the testimony of Mr. Stavropoulos, the Company's decoupling proposals are designed to remove the Company's dependency on gas consumption by its customers to obtain the revenue the Company needs to operate its business. As such, decoupling would facilitate the expansion of gas efficiency programs. With the onset of a significant ramp-up of gas efficiency programs in Rhode Island, the Company believes that revenue decoupling is an essential element to the successful implementation of those programs.

Q. CAN YOU SUMMARIZE, IN GENERAL, HOW THE RPC MECHANISM WOULD WORK, AS PROPOSED BY THE COMPANY?

A. Yes. By rate class, the Company will calculate Target billing month delivery revenues[1] per customer ("RPC"), for each month of the Rate Year, using the billing determinants and class revenue requirements approved by the Commission in this proceeding. After the close of every billing month, for each rate class, the Company will calculate: (1) actual RPC; (2) the difference between actual RPC and Target RPC and (3) the total RPC revenue surplus or shortfall, which will be determined by multiplying the difference between actual and Target RPC times the number of customers. Annually, the Company will calculate an RPC rate adjustment, by rate class, to credit or charge customers for the cumulative RPC revenue surplus or shortfall, including interest. I have provided additional detail on these calculations in Section II.B.2.

B. DECOUPLING MECHANISM DESIGN PARAMETERS

1. RPC Decoupling Mechanism Rate Classes

[1] The term "delivery revenues" is used throughout this testimony to refer to base revenues (not including Gas Cost Recovery, Gross Earnings Tax, Energy Efficiency or DAC revenues) from firm sales and transportation customers.

Q. WHICH RATE CLASSES IS THE COMPANY PROPOSING THAT THE RPC DECOUPLING MECHANISM WILL BE APPLIED TO?

A. The Company is proposing that the RPC decoupling mechanism be applied to all firm rate classes. As I will explain below, the Company's proposed RPC decoupling mechanism would not be applied to new Commercial and Industrial customers in rate classes (1) Large Low Load Factor; (2) Large High Load Factor; (3) Extra Large Low Load factor; and (4) Extra Large High Load Factor.

Q. PLEASE EXPLAIN WHY THE COMPANY IS PROPOSING TO EXCLUDE NEW CUSTOMERS IN COMMERCIAL AND INDUSTRIAL LARGE AND EXTRA LARGE RATE CLASSES FROM THE RPC DECOUPLING MECHANISM.

A. If the Company's Proposed RPC Decoupling mechanism were to be applied to new customers in the Commercial and Industrial Large and Extra Large rate classes, these prospective customers could be required to make significant additional payments to offset some of the customer connection costs. To avoid these additional payments, these prospective customers could instead locate in other states or to use fuels that are more harmful to the environment than natural gas.

Q. PLEASE EXPLAIN WHY THIS WOULD OCCUR.

To serve any new customer, the Company incurs costs to install a meter and service, and to construct a main extension if the prospective customer is not located along an existing distribution main; the Company will also collect additional delivery revenues from the new customer. If the expected revenue stream over time from the prospective customer does not offset the customer connection costs, the Company may require the customer to provide an additional payment, which is commonly referred to as a Contribution in Aid of Construction ("CIAC"). The size of the additional payment is a factor, along with many other economic and business considerations, that may cause the prospective customer to decide to use another energy source or to locate in another state.

An RPC Decoupling mechanism may impact these CIAC payments, because the RPC decoupling mechanism causes the net incremental delivery revenues that the Company will collect from a new customer, after accounting for the new customer's above-average revenues that would be credited to all customers, to be equal to the Rate Year Revenue target for that class, regardless of that customer's actual demand.

The Company's proposed RPC decoupling mechanism will not materially impact the new customer decision-making process for customers in Residential heating and non-heating classes because CIACs for these customers are fixed for all customers in the class, and are not based on individual revenue streams.

Also, the Company's proposed RPC decoupling mechanism will not materially impact the decision making process for prospective new customers in Commercial and Industrial Small and Medium rate classes[2] because customers in these classes are relatively homogeneous. There is little difference between the average customer and the largest or the smallest customers in these classes, and therefore different sized customers in these classes will have little effect on the CIAC calculations for prospective customers in these classes. However, there are significant differences between the largest, smallest and average customers in the each of the four C&I Large and Extra Large rate classes. The largest prospective customers in these classes could decide to locate in another state or to use another fuel, if required to provide a CIAC that is related to the Rate Year target delivery revenues per customer for that class rather than the actual stream of expected delivery revenues from the customer.[3] To the customer, the CIAC is another cost that could influence their decision to locate or expand in the Company's service territory.

Q. PLEASE EXPLAIN THE DETAILS OF THE COMPANY'S PROPOSAL TO EXCLUDE NEW CUSTOMERS IN THESE CLASSES.

A. The Company's proposal to exclude new customers in C&I Large Low Factor, Large High Load Factor, Extra Large Low Load Factor and Extra Large High

[2] The Company's gas service and main installation policy states that "All commercial and industrial applications are priced on an individual basis.......customers are charged a minimum fixed fee of $600." (National Grid Application For Natural Gas Policies And Procedures, Section 3.1.)

[3] The Company determines the level of the CIAC required from a prospective customer based on the expected stream of delivery revenues from the new customer, the costs to connect the new customer and the threshold required Internal Rate of Return. If the Company's proposed RDM applied to prospective Large and Extra Large C&I customers, the expected revenue streams would be based on rate year RPC values for that rate class, rather than expected billed revenues to the prospective

Load Factor classes from the RPC Decoupling mechanism includes the following considerations:

- The RPC mechanism calculations will not include any billing data (e.g. delivery revenues or customer counts) associated with new customers in these classes.
- The Rate Year billing determinants that Mr. Czekanski has developed do not include billing determinants for any new customers in the C&I Large and Extra Large rate classes.

Q. WILL NEW CUSTOMERS IN COMMERCIAL AND INDUSTRIAL LARGE AND EXTRA LARGE RATE CLASSES BE ALLOWED TO PARTICIPATE IN THE COMPANY'S ENERGY EFFICIENCY PROGRAMS?

A. Yes, in keeping with the Company's commitment to promote the efficient and wise use of natural gas for all customers, the Company will ensure that new customers in the C&I Large and Extra Large rate classes are fully informed on appropriate energy efficiency options; a draft copy of the Energy Efficiency Awareness Form that will be provided to all new C&I Large and Extra Large customers is included as Attachment NG-JDS-2.

customer. The RPC Decoupling mechanism would credit the difference between expected billed revenues and rate year RPC from the new customer to all customers in that rate class.

Q. FINALLY, PLEASE EXPLAIN HOW THE COMPANY DEFINES "NEW LARGE AND EXTRA LARGE CUSTOMER."

A. For the RPC Decoupling mechanism, the Company defines a new Large or Extra Large customer to be a gas load that will require that the Company make additional investments to serve that load. For example, based on this definition, an interruptible load or non-firm load that switches to firm service in one of the Large or Extra Large rate classes would not be considered a new customer unless the Company is required to make additional investments to provide firm service to that load.

2. **RPC Decoupling Calculations**

Q. PLEASE EXPLAIN HOW THE RPC DECOUPLING ADJUSTMENTS WILL BE CALCULATED.

A. For each rate class, the Company will make the following calculations:

1. Target billing month delivery revenues per customer will be calculated for each rate class, for each billing month of the Rate Year, using the billing determinants[4] and class revenue requirements approved by the Commission in this proceeding. The RPC decoupling mechanism would remain in effect and target billing month delivery revenues would continue to be calculated based on Rate Year billing determinants and class revenue requirements until the rates resulting from the Company's next rate increase request are made effective by Commission order.

2. After the close of every billing month the Company will make the following calculations for each rate class:

   a. Actual billing month delivery revenues per customer will be calculated by dividing (i) actual delivery revenues[5] produced by base distribution rates by (ii) the number of customers.

   b. The difference between (i) target billing month RPC delivery revenues (from 1. above) and (ii) actual billing month distribution (from 2a. above) will be calculated.

   c. The billing month revenue surplus or shortfall will be calculated by multiplying (i) the difference between target and actual delivery revenues per customer (from 2b above) times (ii) actual number of customers in the month.

   d. The billing month revenue surplus or shortfall will be recorded in a deferred account.

   e. Interest on the average monthly deferred balance will be calculated at the same interest rate that is used to calculate interest expense on the Company's deferred DAC and GCR balances, which is 200 basis points below the Bank of America Prime Rate.

3. The Company will include an annual decoupling reconciliation report and decoupling adjustment calculation as part of the DAC filing that is made August 1 of each year. For this filing, the Company will calculate an RPC rate adjustment for each rate class; the RPC adjustment will be determined so that the balance in the class-specific deferred RPC mechanism account at the end of June of that year is returned to (in the case of an over collection) or recovered from (in the case of an undercollection) the customers in that class at an equal rate per therm, based on projected rate class therm delivery

[4] The Company's support for the rate year billing determinants includes detail by billing month.
[5] Delivery revenues do not include RPC adjustment revenues.

quantities[6] for the twelve months ended November of the following year.[7] Each RPC adjustment will be included in the DAC charged to that rate class.

Q. PLEASE EXPLAIN HOW THE RPC DECOUPLING ADJUSTMENT CALCULATIONS THAT YOU DESCRIBED AND DISCUSSED IN YOUR LAST RESPONSE WOULD NEED TO BE MODIFIED TO REFLECT THE COMPANY'S PROPOSED THREE YEAR RATE PLAN.

A. One simple change must be made in the RPC Decoupling calculations to reflect the three year Rate Plan that Mr. Laflamme discusses in his testimony. Rather than having one set of twelve monthly revenue per customer targets, target billing month delivery revenues per customer will be calculated for each billing month of each of the three Rate Years for each rate class, using the billing determinants and class revenue requirements approved by the Commission in this proceeding. The RPC decoupling mechanism would remain in effect after Rate Year 3, and target billing month delivery revenues would be continue to be based on Rate Year 3 billing determinants and class revenue requirements until the rates resulting from the Company's next rate increase request are made effective by Commission order.

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[6] The term "delivery quantities" is used throughout this testimony to refer to the gas deliveries made by to sales and transportation customers, measured in therms and Dekatherms.

[7] The RPC rate adjustment calculation will include (positive or negative) interest expense throughout the period that the RPC rate adjustment will be in effect.

Q. HAS THE COMPANY PREPARED EXAMPLES OF RPC ADJUSTMENT CALCULATIONS AND THE DEFERRED ACCOUNT ENTRIES?

A. Yes, example calculations are provided and explained in the testimony of Peter Czekanski. Mr. Czekanski is also testifying to the RPC decoupling tariff.

C. <u>OTHER CONSIDERATIONS</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RPC DECOUPLING SCHEDULE IN MORE DETAIL.

A. There are several elements in the Company's proposed schedule: (1) the reconciliation period; (2) the filing date; and (3) the effective date for each RPC adjustment.

The Company proposes to make the RPC rate adjustments effective on November 1 of each year; the RPC filing will be included with the Company's annual DAC filing. Also, the Company proposes that the RPC adjustments be filed with the Commission on August 1 of each year, which will allow three months for Commission review. Finally, the Company proposes that the RPC adjustment calculations – the reconciliation period – be based on data for the twelve months ended June 30th of each year. This will allow the Company sufficient time to prepare the annual August 1 filing.

The table below summarizes the elements of the Company's proposed RPC decoupling schedule:

	Rate Year	Annually Following Rate Year
Effective date of new base rates	November 1, 2008	N/A
RPC Reconciliation period	Nov 2008 – June 2009	12 months ended June of each year
RPC Adjustment filing	August 1, 2009	August 1 of each year
RPC Adjustment in effect	November 1, 2009	November 1 of each year

Q. THE COMPANY CURRENTLY HAS A WEATHER NORMALIZATION ADJUSTMENT ("WNA") TO CHARGE OR CREDIT CUSTOMERS FOR THE REVENUE EFFECT OF WARMER OR COLDER THAN NORMAL WEATHER. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE WNA IN THIS PROCEEDING?

A. The Company's proposed RPC decoupling mechanism will charge or credit customers in all rate classes for the revenue impact of the difference between actual revenues per customer (i.e. not weather normalized) and rate year revenues per customer (i.e. weather normalized) as established in each rate increase proceeding. As proposed, the RPC decoupling mechanism takes into account the revenue impact of (1) weather related differences in usage and (2) differences in usage that are caused by non-weather factors such as customer conservation.

Therefore, if the Commission approves the Company's RPC decoupling mechanism as proposed, the currently effective WNA is duplicative and can be canceled.

Q. WHAT DOES CONCENTRIC'S RESEARCH ON RECENTLY PROPOSED DECOUPLING MECHANISMS INDICATE ABOUT WEATHER NORMALIZATION ADJUSTMENT CLAUSES?

As shown in Attachment NG-JDS-3, the vast majority of LDCs have implemented[8] decoupling mechanisms that account for the revenue impact of both weather and non-weather related changes in customer usage. Nineteen of the twenty five decoupling mechanisms include a weather normalizing adjustment that is either a separate mechanism from the decoupling mechanism, or "built into" the decoupling mechanism.

Q. MR. CZEKANSKI IS PROPOSING IN HIS TESTIMONY TO ADD A CAPITAL EXPENDITURE TRACKER TO THE DISTRIBUTION ADJUSTMENT CLAUSE TARIFF. DOES THE CAPITAL EXPENDITURE TRACKER HAVE ANY EFFECT ON THE CALCULATION OF THE RPC DECOUPLING MECHANISM?

A. No, the Company's proposed Capital Expenditure Tracker is totally independent of the RPC Decoupling Mechanism; any refunds or collections associated with the Accelerated Pipe Replacement Program will not be included in the RPC Decoupling Calculations.

[8] These observations include those LDCs that are waiting for a regulatory decision concerning a proposed decoupling mechanism.

Q. ALSO, MR. LAFLAMME DISCUSSES IN HIS TESTIMONY A CAPITAL EXPENDITURE RECONCILIATION THAT WOULD BE A COMPONENT OF THE CAPITAL EXPENDITURE TRACKER DURING THE THREE YEAR RATE PLAN. DOES THE CAPITAL EXPENDITURE RECONCILIATION HAVE ANY EFFECT ON THE CALCULATION OF THE RPC DECOUPLING MECHANISM?

A. No, as Mr. Laflamme explains in his testimony, if the Company's Capital Spending in a Rate Year is less than the projected Capital Spending that the revenue requirement for that Rate Year is based on during the three year rate plan, customers would receive a rate credit in an upcoming period, based on the revenue requirement impact of the difference between actual Capital Spending and projected Capital Spending for that Rate Year. Therefore, to prevent a double counting of the impact of a shortfall in Capital Spending, the RPC decoupling mechanism will reconcile actual delivery revenues per customer with Rate Year Target delivery revenues per customer, unadjusted for the difference between planned and actual Capital Spending.

III. NATIONAL GRID EXPERIENCE WITH CUSTOMER CONSERVATION

Q. IN MR. STAVROPOULUS' TESTIMONY, HE STATES THAT THE COMPANY HAS EXPERIENCED A LOSS OF REVENUE DUE TO REDUCED CUSTOMER USAGE. HAVE YOU PERFORMED AN ANALYSIS SHOWING THIS?

A. Yes, National Grid customers have made dramatic reductions in gas usage in recent years. For example, Attachment NG-JDS-4 shows that between June 2004 and December 2007, annual gas consumption by the typical National Grid Residential Heating customer, measured by normalized use per customer ("NUPC"), decreased from 1,025.4 therms to 908.2 therms, a decrease of 117.2 therms, or 11.4%.[9]

Attachment NG-JDS-4 also demonstrates that in the past several years Residential Heating NUPC is significantly below the NUPC established in the Company's most recent rate case, which was used to set National Grid's currently effective rates.[10] Based on rate case residential heating billing determinants, rate case NUPC for this class was 1,029.3 therms;[11] which is 121.1 therms or 11.8% higher than actual NUPC for the 12 months ended December 2007. These large and sustained differences between the Residential Heating Rate Year NUPC and recent actual NUPC demonstrate that in the past few years National Grid has not

[9] Over this period Residential Heating NUPC has decreased at an annual rate of 3.4%.
[10] Current base rates were made effective July 1, 2002; Docket Number 3401.
[11] Residential Heating Rate 12 billing determinants: 185,288,884 therms, 2,160,267 total customer-months or 180,022 average monthly customers.

had a reasonable opportunity to earn the rate of return that was authorized in the rates that have been in effect since July 2002.

Q. HAVE NATIONAL GRID'S COMMERCIAL AND INDUSTRIAL ("C&I") CUSTOMERS ALSO BEEN CONSERVING AT RATES THAT ARE COMPARABLE TO RESIDENTIAL HEATING?

A. Yes, in recent years the gas use of National Grid's typical Small and Medium C&I customers has also declined dramatically. Attachment NG-JDS-5 shows that between June 2004 and December 2007 annual weather normalized gas consumption by the typical National Grid Small C&I customer decreased from 1,449.7 therms to 1,260.6 therms, which is a decrease of 189.1 therms, or 13.0%.[12]

Attachment NG-JDS-5 also demonstrates that in the past several years Small C&I NUPC is significantly below the rate class NUPC from the Company's most recent rate case. Based on rate case billing determinants, Small C&I NUPC for this class was 1,438.1 therms,[13] which is 177.5 therms or 12.3% higher than actual NUPC for the 12 months ended December 2007.

Attachment NG-JDS-6 shows that between June 2004 and December 2007 annual weather normalized gas consumption by the typical National Grid Medium C&I

[12] Over this period Small C&I NUPC has decreased at an annual rate of 3.9%.
[13] Small C&I Rate 21 Billing determinants: 26,499,006 therms, 221,124 total customer-months or 18,427 average monthly customers.

customer decreased from 12,430.8 therms to 11,499.3 therms, which is a decrease of 931.5 therms, or 7.5%.[14]

Attachment NG-JDS-6 also demonstrates that in the past several years Medium C&I NUPC is significantly below the rate class NUPC from the Company's most recent rate case. Based on rate case billing determinants, rate case Medium C&I NUPC was 13,204.1 therms,[15] which is 1,704.8 therms or 12.9% higher than actual NUPC for the 12 months ended December 2007.

Q. THE STARTING DATE FOR ALL OF YOUR ANNUAL NUPC ANALYSIS IS JUNE 2004. WHY DID YOU SELECT THIS STARTING POINT?

A. The Company provided monthly data from July 2003 to the present, so the earliest annual value that I could calculate was for the twelve months ended June 2004. Data that was readily available for earlier periods than July 2003 was not compatible with the more recent data. However, I have reviewed usage trends for many other gas distribution companies, and I expect that National Grid has likely been experiencing declining NUPC starting perhaps as early as 2000 or 2001.

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14 Over this period Medium C&I NUPC has decreased at an annual rate of 2.2%.

15 Medium C&I, Rate 22 billing determinants: 54,619,053 therms, 49,638 total customer-months or 4,136.52 average monthly customers.

Q. IN YOUR OPINION, WHY HAS THE COMPANY'S RESIDENTIAL HEATING NUPC DECREASED SO DRAMATICALLY IN RECENT YEARS?

A. The decline that National Grid has experienced in typical customers' gas use in the past several years is the result of market forces and customers' responses to those forces. Specifically, recent decreases in NUPC have been caused by a combination of "passive" and "active" conservation measures and practices that National Grid's customers have adopted.

Q. PLEASE EXPLAIN WHAT IS MEANT BY "PASSIVE" CONSERVATION.

A. Passive conservation refers to situations in which customers are forced to replace outdated, failing gas appliances with new appliances that are more energy-efficient. For example, the average useful life of residential space heating equipment is approximately 20 to 25 years and water heaters last approximately 10 years. Therefore, every year approximately 4% to 5% of residential customers are forced to replace their current (i.e. 20 to 25 year old, relatively inefficient) space heating equipment, with equipment that meets current efficiency standards and is therefore significantly more efficient. Similarly, approximately 10% of residential customers are forced to replace their current water heaters with equipment that meets the current efficiency standards. These customer actions are considered "passive" adoptions of conservation measures because these customers do not purchase more energy efficient equipment as a result of utility-funded conservation programs, because they are necessarily conservation-conscious or because they have prepared an analysis of the costs and benefits of prematurely replacing old equipment with new energy efficient equipment. Rather, these customers will improve the energy efficiency of their gas burning equipment, with an associated decrease in NUPC, simply because they have been forced to replace their current lower efficiency equipment with new equipment that has significantly higher energy efficiency.

Q. WHY ARE THE ENERGY EFFICIENCIES OF MAJOR RESIDENTIAL GAS APPLIANCES IMPROVING OVER TIME?

A. Major residential gas appliances have become more energy efficient over time as a result of:

- Federally-mandated improvements in appliance efficiency.
- Advances in technology that result in appliances that are better, lower cost, and more efficient.
- Competitive markets and general consumer awareness of high energy costs that have motivated manufacturers to improve the energy efficiency of gas appliances.

Q. HAVE YOU PERFORMED RESEARCH ON FEDERALLY-MANDATED IMPROVEMENTS IN APPLIANCE EFFICIENCY?

A. Yes. I have prepared Attachment NG-JDS-7 to show the minimum efficiency standards that the Department of Energy's ("DOE") Office of Codes and Standards has set for natural gas space heaters and water heaters.

Q. PLEASE EXPLAIN ACTIVE CONSERVATION AND DESCRIBE ACTIVE CONSERVATION ACTIONS THAT RESIDENTIAL CUSTOMERS CAN TAKE.

A. There are a variety of voluntary (i.e. active) actions that customers can take to reduce gas consumption. These actions can be categorized as (1) short term reversible actions or (2) long term permanent actions. We expect that in response to recent high gas prices, almost all National Grid customers have tried to conserve gas use by taking simple steps that are low cost / no cost conservation methods, such as turning down thermostats, closing off unused rooms, and lowering water heater temperature settings. These measures are viewed as reversible because they generally cause inconvenience and lifestyle disruptions that customers may not elect to continue permanently.

Examples of common long term permanent energy efficiency actions include: (a) installing additional insulation in attics, basements and outside walls; (b) installing door and window weather stripping; (c) installing setback thermostats; (d) replacing existing windows and doors with new energy conserving windows and doors; and (e) purchasing high efficiency, rather than standard efficiency equipment. In contrast to the short run conservation measures that are low cost or no cost, many of the permanent conservation actions involve considerable expense and require specialized expertise to install.

Q. HOW DO CUSTOMERS DECIDE TO INSTALL PERMANENT CONSERVATION MEASURES?

A. Residential customers may decide to install permanent conservation measures if they have (1) sufficient understanding of the costs and benefits of installing energy efficiency measures that are specific to their circumstances and (2) the resources to pay for these conservation measures.

Customers are generally motivated to invest in permanent conservation measures if they believe that the energy savings will offset the costs of the measures. The high costs of most of these permanent measures discourage many customers from taking actions that would produce long run net benefits.

Q. IN YOUR OPINION, WHY HAS NATIONAL GRID'S RESIDENTIAL HEATING GAS USAGE PER CUSTOMER DECLINED BY MORE THAN 11% SINCE MID 2004?

A. In addition to passive conservation, in the past several years National Grid's residential heating customers have been conserving in response to (1) higher gas prices during this period, and (2) generally higher energy prices.

Q. PLEASE DESCRIBE THE HIGHER GAS PRICES THAT HAVE BEEN EXPERIENCED IN RECENT YEARS.

A. Largely as a result of tightening of supplies, the market price of gas increased in the summer and fall, 2005; gas prices increased dramatically through the fall, 2005 and winter, 2006 in the aftermath of Hurricanes Katrina and Rita, which caused short term production-related supply shortages. Attachment NG-JDS-8 shows National Grid's (1) annual average price per therm for residential heating bundled gas service and (2) residential heating NUPC from June 2004 through December 2007.

Q. PLEASE EXPLAIN THE INTERACTION OF CHANGES IN GAS PRICES AND NUPC THAT IS SHOWN IN ATTACHMENT NG-JDS-8.

A. Attachment NG-JDS-8 shows that from June 2004 until November 2006, the annual price per therm for residential heating bundled gas service <u>increased</u> at a steady rate that averaged over 14% per year during the period. Gas prices have been steadily decreasing in the past year; since November 2006, prices have <u>decreased</u> at an annualized rate of 4.8%.

However, the decline in Residential Heating NUPC has been persistent throughout the entire three and one half year period, June 2004 to December 2007, and has shown no responsiveness to the decreasing prices over the past year. During the thirty month period June 2004 until November 2006 that price increases were averaging over 14% annually, NUPC declined at an annual rate of

3.3%; during the remaining twelve months, November 2006 to November 2007 when gas prices were decreasing by 4.8%, NUPC continued to decline at an annual rate of 3.7%.

Q. IN YOUR OPINION WHY HAVE CUSTOMERS CONTINUED TO REDUCE GAS USE EVEN AFTER GAS PRICES STARTED FALLING AFTER NOVEMBER 2006?

A. It appears that the drop in residential heating NUPC throughout the three and one half year period from June 2004 to December 2007 was primarily the result of a combination of ongoing changes in customer behavior and permanent conservation measures that were installed during this period. In general, heightened customer awareness of high energy prices[16] seems to have caused customers to continue to conserve natural gas, even as gas prices have moderated.

[16] The high cost of energy - electricity, gasoline and natural gas - has been well publicized in recent years.

Q. ATTACHMENT NG-JDS-5 AND ATTACHMENT NG-JDS-6 INDICATE THAT TYPICAL SMALL AND MEDIUM C&I CUSTOMERS HAVE BEEN REDUCING GAS USE AT A RATE THAT IS CONSISTENT WITH RESIDENTIAL HEATING BEHAVIOR. IN YOUR OPINION, ARE THE SMALL AND MEDIUM C&I CUSTOMERS UNDERTAKING THE SAME KINDS OF ACTIVE AND PASSIVE CONSERVATION THAT IS AFFECTING THE RESIDENTIAL HEATING GAS USE?

A. Yes. Attachment NG-JDS-9 and Attachment NG-JDS-10 show that the changes in gas prices experienced by National Grid's Small and Medium C&I customers are very similar to the changes experienced by Residential Heating customers. The actions that the Small and Medium C&I customers have taken in response to the changes in gas prices are also likely to be very similar; much of the gas use by these customers is for heating load, and efforts to conserve will also be somewhat similar.

Q. IN NATIONAL GRID'S RECENT EXPERIENCE, THE GAS USE OF TYPICAL RESIDENTIAL HEATING, SMALL C&I AND MEDIUM C&I CUSTOMERS HAS DECLINED SIGNIFICANTLY. IS IT POSSIBLE THAT GAS USE WILL INCREASE IN THE FUTURE, COMPARED TO CURRENT LEVELS?

A. It is possible that the typical customer's gas use could increase in the future compared to current levels. In addition to the factors that cause active and passive conservation, gas use is influenced by such considerations as customer wealth and income, and customer lifestyle choices. Future increases or decreases in overall customer wealth and / or income by National Grid's customers would result in changes in the same direction[17] in NUPC, other things being equal. Changes in lifestyle, such as people per household, age of household members, and size of house could also cause increases or decreases in NUPC.

Also, just as customers respond to price increases with active conservation measures that decrease NUPC, customers could respond to price decreases with actions that would increase NUPC. Decreases in burnertip gas prices (either on an absolute basis or relative to electric or heating oil) could lead to increases in the number of gas appliances per household and increases in the use of gas per appliance, both of which would increase NUPC.

In summary, although the Company does not project that future real gas prices will decrease significantly, which could trigger increases in NUPC, and although National Grid's Energy Efficiency programs and the continuing effect of passive and active conservation will cause NUPC to decrease, it is possible that NUPC could increase over some future periods.

[17] That is, increases in overall wealth or income would likely result in increases in NUPC; decreases in wealth or income would result in decreases in NUPC.

Q. DO YOU BELIEVE THAT NUPC WILL RETURN TO PRE-2004 LEVELS, GIVEN THE RECENT MODERATION IN GAS COSTS?

A. That is highly unlikely. National Grid's Energy Efficiency programs will certainly result in NUPC, compared to current levels, and the reduction in NUPC due to recently installed passive or active conservation measures is permanent. In addition, Attachments NG-JDS- 8, 9, and 10 clearly show no significant increase in NUPC in recent months despite lower gas costs in the 2006/2007 winter compared with the previous winter.

Q. HOW HAVE THE DELIVERY REVENUES COLLECTED BY THE COMPANY BEEN AFFECTED BY THE DECLINE IN RESIDENTIAL HEATING NUPC?

A. As a direct result of the decline in Residential Heating NUPC from 1,025.4 therms in June 2004 to 908.2 therms in December 2007, delivery revenues per residential heating customer decreased from $455.24 to $415.50, which is a decrease of $39.74 per customer or 8.7%. This reduction in revenue per customer means that annual National Grid Residential Heating weather normalized delivery revenues for the 12 months ended December 2007 are lower than delivery revenues for the 12 months ended June 2004 by almost $7.6 million.[18] This magnitude of revenue loss is unprecedented.

[18] $39.74 revenue decrease per customer x 191,355 average annual customers as of December 2007 = $7,604,448.

IV. U.S. EXPERIENCE WITH CUSTOMER CONSERVATION

Q. HAVE OTHER LDCS IN THE U.S. ALSO EXPERIENCED CUSTOMER-DRIVEN CONSERVATION AND DECLINING USE PER CUSTOMER?

A. Yes, they have. This topic has been the subject of considerable analysis and discussion since at least 2000, when the American Gas Association issued its first report on customer conservation. The AGA published an update to the first report in 2003, Patterns in Residential Natural Gas Consumption, 1997 – 2001 (June 16, 2003) (the "AGA Report" or "Report"), which provides a comprehensive analysis of improving gas equipment efficiencies, and the impact of these efficiency improvements on NUPC. The AGA Report provides separate analyses for the Northeast region, and is therefore more applicable to the Company than an analysis that reports results for the entire country. A copy of the Report is provided as Attachment NG-JDS-11.

Q. PLEASE SUMMARIZE THE AGA REPORT.

A. The AGA Report, which is based on government and AGA surveys,[19] found that average weather normalized Residential Heating NUPC in the Northeast declined approximately 3% between 1997 and 2001. Major factors identified as contributing to this decline included steady improvements over a long period of time in:

[19] The 2003 AGA report expands on an analysis that was provided in an earlier AGA report, Patterns in Natural Gas Consumption Since 1980, American Gas Association, February 2000.

- Residential natural gas space heating equipment efficiency (measured as annual fuel utilization efficiency – AFUE)
- Residential natural gas water heater efficiency
- Home thermal efficiency (e.g. insulation, air infiltration)

Q. HAS THE AGA PREPARED ANY OTHER REPORTS THAT ADDRESS CUSTOMER CONSERVATION?

A. Yes, in March 2007 the AGA published An Economic Analysis of Consumer Response to Natural Gas Prices, by Frederick Joutz and Robert P. Trost, prepared for the AGA, March 2007 ("AGA Elasticity Report"), which has been provided as Attachment NG-JDS-12.

Q. PLEASE SUMMARIZE THE AGA ELASTICITY REPORT.

A. The Executive Summary to the AGA Elasticity Report (page 1) states that, "The consumption of natural gas per household has been declining, on a weather-normalized basis, since about 1980. Over time, natural gas consumers have been tightening their homes, purchasing more efficient appliances and turning down their thermostats. Given the significant increase in natural gas prices since 2000, the American Gas Association (AGA) decided to examine whether or not the trend in declining use has changed in this higher-priced environment. The results of this study are based on monthly data submitted by 46 local natural gas distribution companies that serve nearly 30 percent of all residential natural gas customers throughout the U.S. …The key findings of the (Elasticity Report) are as follows:

- A trend in declining use per residential natural gas customer of 1 percent annually has been documented back to 1980. This decline rate has accelerated since the year 2000.
    - Weather-adjusted use per residential customer fell by 13.1 percent from 2000 through 2006.
    - The annual rate of decline in this 2000 to 2006 timeframe more than doubled relative to the pre-2000 period, increasing to 2.2 percent annually.
    - Further acceleration was witnessed in the 2004 to 2006 period, as evidenced by a 4.9 percent annual rate of decline."

Q. WHAT DO YOU CONCLUDE FROM THE AGA ELASTICITY REPORT?

A. This report confirms that customer conservation has had a significant impact on gas LDCs nationwide. The overall decrease in residential heating winter[20] use per customer of 4.9% per year between 2004 and 2006 experienced by the participating LDCs is consistent with and validates the 3.3% per year decrease in annual NUPC that National Grid experienced during the same period.

V. RATE DESIGN OVERVIEW

Q. HAVE OTHER LDCS BEEN CONSIDERING RATE DESIGN MEASURES TO ADDRESS THE IMPACT OF CUSTOMER DRIVEN CONSERVATION ON DELIVERY REVENUES AND EARNINGS?

A. Yes. Starting in 2005, there has been a growing awareness throughout the country that customer conservation is causing significant declines in NUPC and

[20] The AGA Elasticity Report defined the winter period as October through March.

delivery revenues for almost all gas LDCs. In response, LDCs and regulators have developed a variety of rate design measures.

Q. WHY ARE NEW RATE DESIGN MEASURES BEING CONSIDERED BY LDCS IN THE US?

A. In this period of significant customer conservation, new ratemaking approaches are being considered.

In simple terms, traditional ratemaking consists of (1) determining the revenue requirement, which is the level of expenses, depreciation, return and taxes that reflect the ongoing cost of remaining in business and (2) determining the billing units (i.e. "billing determinants") that reflect the levels of service that the LDC will be providing to its customers. Rates are calculated by dividing the revenue requirement by the billing determinants.[21]

Until recently, traditional ratemaking has generally allowed LDCs a reasonable opportunity to earn a fair rate of return for its shareholders. Although the ratemaking formula does not typically account for increased costs of doing business over time, until recently LDCs could partially offset inflationary pressures on earnings through a combination of cost effective growth and LDC initiatives to improve productivity and control costs. However, the recent

[21] Rate setting is much more complicated than this simplified description: proper responsibility for the total revenue requirement is assigned to the rate classes by detailed multi-step analyses; rate structures for each class may have several components including monthly customer charges, demand charges,

declines in gas use are so significant that the impact of conservation-driven reductions in delivery revenues has led many LDCs throughout the country to examine appropriate rate design measures to address this new ratemaking reality.

Q. HAS THE NATIONAL ASSOCIATION OF REGULATORY AND UTILITY COMMISSIONS (NARUC) COMMENTED ON CUSTOMER CONSERVATION AND DECOUPLING?

A. Yes, in 2005 NARUC passed a resolution that stated that decoupling mechanisms "…may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas."[22]

A year earlier, the American Gas Association and the Natural Resources Defense Council submitted a joint resolution to NARUC that the two groups were in agreement on "the importance of state Public Utility Commissions' consideration of innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility companies, utility shareholders and other stakeholders."[23]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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and delivery quantity charges; final rates are based not only on detailed cost analyses but also on other considerations such as rate continuity.

[22] National Association of Regulatory Utility Commissioners "Resolution on Energy Efficiency and Innovative Rate Design," adopted November 16, 2005.

[23] "Joint Statement of American Gas Association and National Resources Defense Council," submitted to the National Association of Regulatory Commissioners, July 2004.

Attachments of
James D. Simpson

Attachments

Attachment NG-JDS-1	James D. Simpson Qualifications and Experience
Attachment NG-JDS-2	Draft Energy Efficiency Awareness Form
Attachment NG-JDS-3	Summary of Gas LDC Decoupling Mechanism Proposals
Attachment NG-JDS-4	Residential Heat Rolling 12 Month NUPC Graph: June 2004 - Dec 2007
Attachment NG-JDS-5	Commercial and Industrial small Rolling 12 Month NUPC Graph: June 2004 - Dec 2007
Attachment NG-JDS-6	Commercial and Industrial Medium Rolling 12 Month NUPC Graph: June 2004 – Dec 2007
Attachment NG-JDS-7	Efficiency Standards
Attachment NG-JDS-8	Residential Heat Price/Use per Customer Analysis
Attachment NG-JDS-9	Commercial and Industrial Small Price/Use per Customer Analysis
Attachment NG-JDS-10	Commercial and Industrial Medium Price/Use per Customer Analysis
Attachment NG-JDS-11	AGA 2003 Report
Attachment NG-JDS-12	AGA 2007 Elasticity Study

NG-JDS-1

James D. Simpson
Vice President

Mr. Simpson is a senior executive with more than 30 years of experience in the energy industry. He has held positions at a natural gas utility; an entrepreneurial company providing a proprietary service to generating companies; and state regulatory agencies. His responsibilities have included pricing strategy, regulatory affairs, analysis and planning and business development.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Affairs

Representative engagements and responsibilities include:

- Prepared strategic assessment of PBR options for South Central utility
- Prepared validation of sales forecast and analysis of declining use per customer for Northeast utility
- Prepared rate design for Mid Atlantic utility for rate increase filing
- Prepared marginal cost study and testimony for Northeast utility
- Prepared marginal cost study and rate design for Northeast utility
- Prepared rate design and testimony for Northeast utility
- Prepared cost of service for Northeast generating facility
- Prepared assessment of forecast methodology and forecast accuracy for Northeast utility
- Prepared assessment of forecast methodology and forecast accuracy for North central utility
- Served as primary rate design witness for Bay State Gas Company, Northern Utilities (Maine and New Hampshire) and Granite State Gas Transmission on issues including rate reclassification, restructuring, market competitiveness, and earnings stability

Business Strategy and Operations

Representative engagements and responsibilities include:

- Held position of Chief Operating Officer for a New England gas company, responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning
- Developed marketing plan and developed and implemented sales strategies
- Developed brand awareness strategy; created coordinated electronic and physical marketing materials; created and implemented a trade publication strategy. Simplified and shortened sales process; focused on prospective client decision making and understanding of company value proposition
- Implemented new Optimal Growth strategy to identify opportunities and track investments
- Led team that created plan to align company structure and culture with new competition-based growth and customer-focus strategy. Led organization during implementation of new strategy, structure, and culture

Contract Negotiations

Representative engagements and responsibilities include:

- Successfully negotiated contract for first new North America operations site in four years

- Persuaded state regulators to reverse established regulatory policies in conflict with company strategy
- Directed negotiation of groundbreaking labor contract that allowed company to use outside contractors and to reduce the union work force by 10%
- Negotiated agreement with pipeline for short term incremental capacity at significant savings

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2005 – Present)
Vice President
Assistant Vice President
Executive Advisor

Separation Technologies, Inc. (2001 – 2004)
Vice President, Business Development

Bay State Gas Company (1982 – 2000)
Senior Vice President, Large Customer Sales and Regulatory Affairs (1999 – 2000)
Senior Vice President/COO of Regulated Utility Business (1996 – 1999)
Vice President, Market Analysis and Pricing (1993 – 1996)
Director/Manager of Rates (1982 – 1993)

Massachusetts Department of Public Utilities (1978 – 1982)
Director
Senior Analyst

Wisconsin Public Service Commission (1977 – 1978)
Senior Analyst

EDUCATION

M.S., Economics, University of Wisconsin
B.A., Economics, University of Minnesota, magna cum laude

NG-JDS-2

nationalgrid | KEYSPAN

DRAFT

Energy Efficiency Awareness Form - The following statement is intended to portray, conceptually, the documentation necessary to capture ongoing energy efficiency program outreach efforts:

National Grid, as part of our mission to offer our customer base with comprehensive energy efficiency solutions, provides the enclosed program materials for your review and consideration. The program materials are intended to provide guidance and incentives toward the installation of energy efficiency measures. Program guidelines and product applicability are included.

By signing below, I acknowledge that I have received a copy of National Grid's energy efficiency program brochure and that the programs have been explained and presented to my satisfaction.

____
Signature Date

Note: Each form will be accompanied by applicable National Grid Energy Efficiency program materials/ brochures

NG-JDS-3

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
1	AR	Arkansas Oklahoma Gas Corp.	D-07-026-U	11/20/07	Annual weather normalized actual class revenues compared to target (rate case) revenues[1]	Residential and Small Business	Annual true up; Nov 1 – Oct 31	WNA[2] CGA[3] Municipal Tax Clause
2	AR	Arkansas Western Gas	D-06-124-U	7/13/07	Annual actual revenues compared to rate case revenues[4] No class true up if (1) customers and volumes or (2) revenues are ≥ TY ("Test Year") levels Separate WNA	Residential (RS-l), Business 1- Sales and Transport (B-l), and Business 2-Sales and Transport (B-2) rate classes.	Annual true up, August – July; adjustment rate in effect following January through December	WNA Tax and fee
3	AR	CenterPoint Arkansas	06- 16 1 -U	10/25/07	Annual actual revenues compared to rate case revenues[18] No class true up if (1) customers and volumes or (2) revenues are ≥ TY levels WNA currently in effect[1]	Residential Firm Sales Service, RS-1, Small Commercial Firm Sales Service, SC-1, Small Commercial Firm Sales Service - Off Peak, SCS-2	Annual true up, January – December adjustment rate in effect following July through June	WNA

1 This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf
2 WNA: Weather Normalization adjustment clause.; WN: weather normalized
3 CGA: Cost of Gas Adjustment clause.
4 This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
4	CA	PG&E	AP-9712020 De-0002046	5/27/04	Rate Plan Revenue Requirement	All	Annual	23 Balancing accounts, Adjustments Core, non-core fixed cost; pension contribution 7 memo accounts Catastrophic Event, Advanced Metering Infrastructure, Financial Hedging
5	CA	SOCal Gas		1998	PBR[5] price cap rate plan	All	Annual	18 Balancing Accounts Pension, PBOP[6], Core, non-core fixed cost 26 memo accounts Catastrophic Event, Intervenor Award ESM[7]
6	CA	Southwest Gas		3/16/04	Rate plan revenue requirement Attrition year increases could be adjusted down if pipe replacement targets missed Actual margin revenues compared to authorized levels	All	Annual	Catastrophic Event, Public Purpose Program, Low Income Energy Efficiency
7	CO	Public Service Co. of CO	D-06S-656G	6/18/07	NUPC true up mechanism Difference between WN actual use per customer and TY UPC, times margin rate times actual customers	Residential RG	Annual	

5 PBR: Performance Based Ratemaking
6 PBOP: Post-retirement other than Pension expense
7 ESM: Earnings Sharing Mechanism

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
8	IL	Central Illinois Light Co.	D-07-0588	Pending filed 11/2/07	Billing month adjustment: the difference between actual class revenues per actual customer vs. TY revenues per TY customer, multiplied by TY customers, plus prior year reconciliation	Residential (GDS-1), Small General (GDS-2)	Monthly with 2 month lag between calculation and billing of adjustment	Uncollectibles CGA Environmental Remediation costs Franchise cost adjustment Government Compliance cost adjustment
9	IL	Central Illinois Public Service Co.	D-07-0589	Pending filed 11/2/07	Billing month adjustment: the difference between actual class revenues per actual customer vs. TY revenues per TY customer, multiplied by TY customers, plus prior year reconciliation	Residential (GDS-1), Small General (GDS-2)	Monthly with 2 month lag between calculation and billing of adjustment	Uncollectibles CGA Environmental Remediation costs Franchise cost adjustment Government Compliance cost adjustment
10	IL	Illinois Power Co.	D-07-0590	Pending filed 11/2/07	Billing month adjustment: the difference between actual class revenues per actual customer vs. TY revenues per TY customer, multiplied by TY customers, plus prior year reconciliation	Residential (GDS-1), Small General (GDS-2)	Monthly with 2 month lag between calculation and billing of adjustment	Uncollectibles CGA Environmental Remediation costs Franchise cost adjustment Government Compliance cost adjustment
11	IL	Peoples Gas Light and Coke Co. and North Shore Gas Co.	D-07-0241, 0242	Pending	Monthly difference between actual and TY ("Test Year") margin per customer, times TY customers, divided by estimated volumes, 2 months later. Actual and target revenues is deferred	Service classes 1N, 1H, and 2	Monthly	CGA Municipal taxes Environmental costs

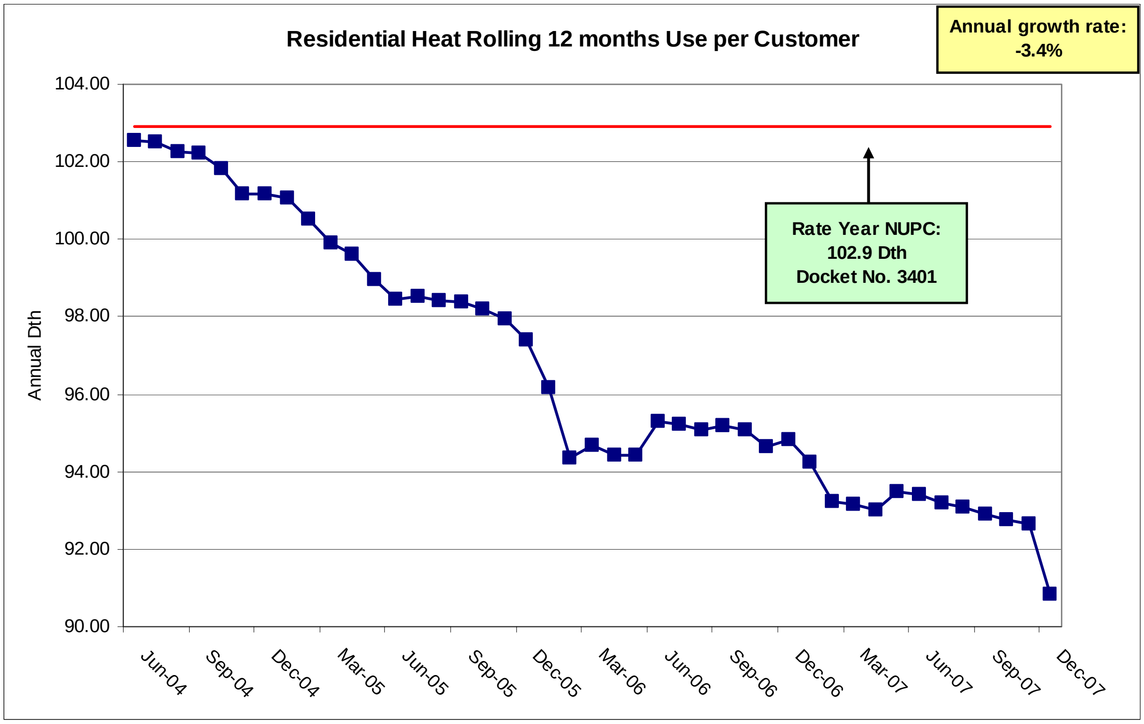
	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
12	IN	Southern Indiana Gas and Electric	C- 43046 C-43112	12/1/06 8/1/07	85% of difference between actual class margins and TY margins by class, adj for growth in customers	Residential, General Service sales; School transportation	Annual recovery of accumulated deferred balance; with reconciliation	Bad debt gas , pipeline safety, bare steel replacement (PSA), normal temperature adjustment
13	KS	Atmos Energy Corp	D-08-ATMG-280-RTS	Pending filed 9/14/07	Difference between test-year average margin per customer and actual average margin per customer (including margins from the WN adjustment) times the monthly average number of billing units for the accounting/recovery period	All Residential, Commercial, Public Authority Bills	Annual	WNA separate
14	MD	Washington Gas Light Company	Case No. 8990	8/6/05	Calculate billing month adjustment based on actual class revenues vs. TY revenues, adjusted for customer growth Reconciliation of actual and target revenues	Rate Schedule Nos. 1, 1A, 2, 2A, 3 and 3A	Monthly with 2 month lag	
15	NC	Piedmont Natural Gas	D-G-9,SUB49 9	11/3/05	Rev Adj by class by month = Target revenues – Actual revenues.: Target: actual customers x (TY base load/cust + TY TS factor x Normal HDD) Interest on deferred	Rate schedules 101, 121, 102, 132, 152, 162	Adj Factor changes Apr, Nov, based on deferred bal at Jan, Aug	Pipeline integrity, PBOP regulatory assets Bad debt (gas)

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
16	NJ	South Jersey Gas /New Jersey Natural Gas		11/9/06	Monthly difference between current actual and TY NUPC, times predetermined weighted margin per therm times actual monthly customers Capped to limit ROE to 10.5%	Resid, Resid Transport, Gen Svc High LF, Comprehensive Transportation and Balancing, Gen Svc Low LF, Small Commercial Rebundled Trans, ED	Annual	WNA
17	NY	Con Ed	06-G-1332	9/25/07	Difference between rate case rate year revenue per customer and actual rate year revenue per customer, times actual rate year customers.	SC No. 2 - Rate I; SC No. 2 - Rate II; SC No. 3 customers with 1-4 dwelling units; and SC No. 3 customers with more than 4 dwelling units, SC No. 9; excluding customers taking service under special rates ED, Low Income, Manuf, Econ by pass	Annual	WNA ESM Trackers for: property taxes, non-Company labor interference expenses, Cap Ex, PBOP, Gas transmission main maintenance, R&D, environmental remediation, pipeline integrity programs, distribution integrity and/or gas inspections
18	NY	National Fuel	C-07-G-0141	12/21/07	Difference between annual TY UPC and current year WN UPC, times block rate times customers	SC 1, SC 2, SC 2A (Res) and SC 3. (GS)	Annually; 12 months ended December data. Effective March 1	WNA
19	OH	Dominion East Ohio	C-07-829-GA-AIR	Pending filed 8/30/07	Difference between order-granted revenues and actual WN revenues with order-granted revenues adjusted to reflect growth in number of customers	GSS, LVGSS, ECTS, LVECTS	New rate effective November 1 annually	Low income subsidy adjustment Uncollectible adjustment

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
20	OH	Duke Energy Ohio, Inc.	C-07-589-GA-AIR	Pending filed 7/17/07	Difference between order-granted revenues and actual WN revenues with order-granted revenues adjusted to reflect growth in number of customers	All sales & transportation customers except Rate IT	Annual	Main replacement rider Low income subsidy adjustment Uncollectible adjustment
21	OH	Vectren	05-1444-GA-UNC	9/13/06	Difference in actual WN revenues, rate case revenues, adjusted for growth in customers. Actual and target revenues are reconciled	Residential sales/ trans: general sales / trans	New rate effective November 1 annually,	
22	OR	Northwest	Renew: UG 163	8/22/03 Initial: 9/12/02; renew 8/25/05	Partial decoupling: Base line rate case per customer adjusted for price elasticity compared to actual WN UPC	Res 1, 2 Commercial 1, 3, 31	Annual, eff Oct 1 each year; adj based on deferred balance as of June 30.	Separate WNA
23	UT	Questar Gas	Docket No. 05-057-T01	5/26/06	Difference between rate case margin per customer, and actual revenue, times actual monthly customers, Reconciling	GS-1, GSS	Semiannually, adjustment to base rates made to amortize current balance over 12 months	WNA: separate

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
24	WA	Avista	UG 060518	12/21/05	Actual WN sales, with new customers removed, compared to TY monthly sales. revenues calculated by multiplying sales diff by approved rate; 90% of diff is deferred Deferral subject to ESM and DSM performance Impact capped at 2%; difference remains in deferred.	RS 101 (residential and small commercial)	Annual, July – June; new adjustment effective Sept 1 Nov 07 – Oct 2010	Tax Adjustment
25	WA	Cascade Natural Gas Corp	UG-060256	1/12/07	Difference between rate case margin per customer and actual WN margin per customer times actual customers Actual and target revenues reconciled	RS 503, 504 (Residential, Commercial)	Annual	

NG-JDS-4


Residential Heat Rolling 12 months Use per Customer
Annual growth rate:
-3.4%
Rate Year NUPC:
102.9 Dth
Docket No. 3401
Annual Dth
104.00
102.00
100.00
98.00
96.00
94.00
92.00
90.00
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
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Jun-07
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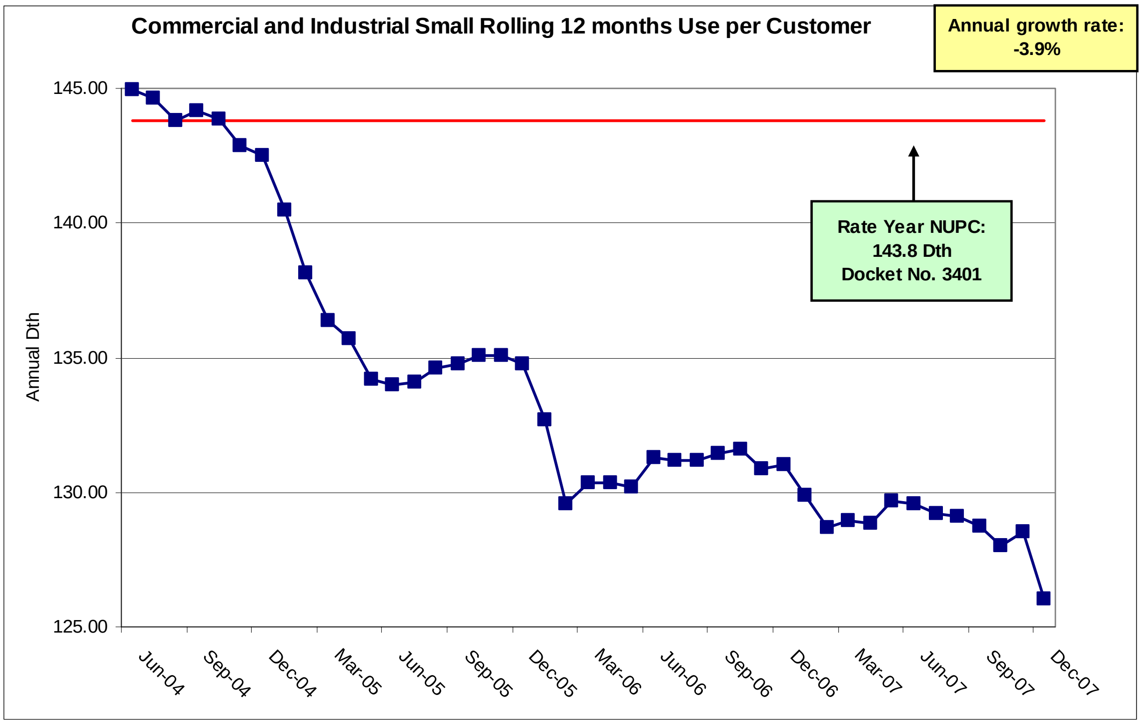
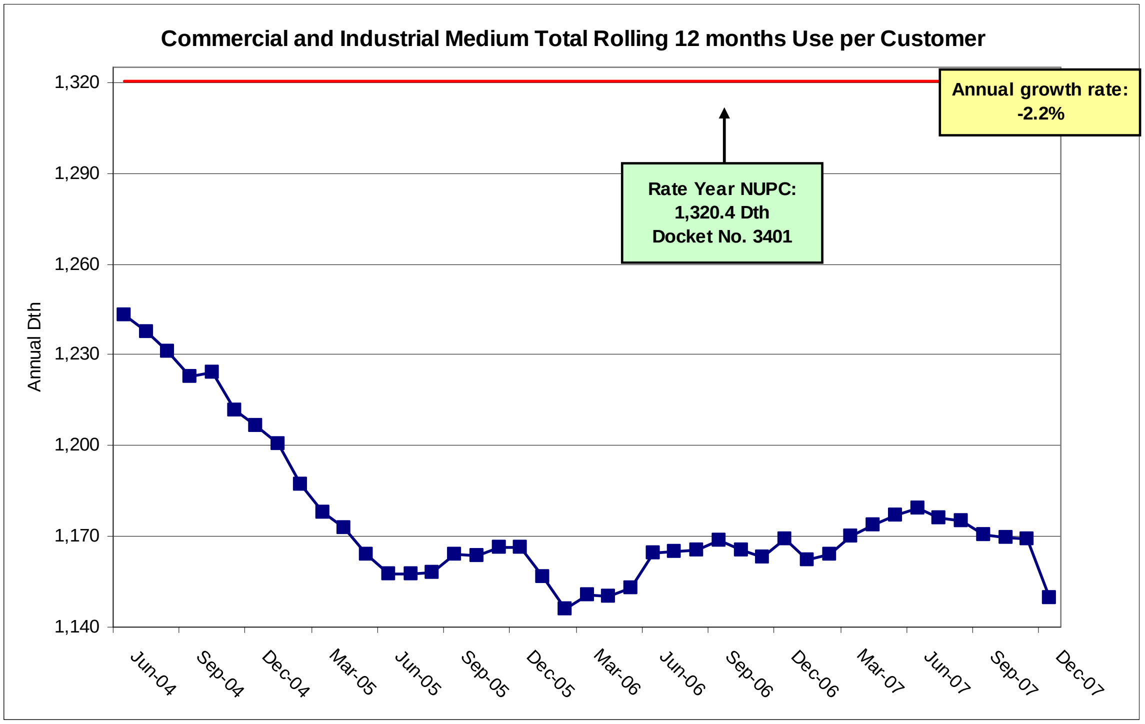
NG-JDS-5


Commercial and Industrial Small Rolling 12 months Use per Customer
Annual growth rate:
-3.9%
145.00
140.00
135.00
130.00
125.00
Annual Dth
Rate Year NUPC:
143.8 Dth
Docket No. 3401
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07

NG-JDS-6


Commercial and Industrial Medium Total Rolling 12 months Use per Customer
Annual growth rate:
-2.2%
Rate Year NUPC:
1,320.4 Dth
Docket No. 3401
Annual Dth
1,320
1,290
1,260
1,230
1,200
1,170
1,140
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07

US Department of Energy

Energy Efficiency Standards - Selected Residential Gas-fired Equipment

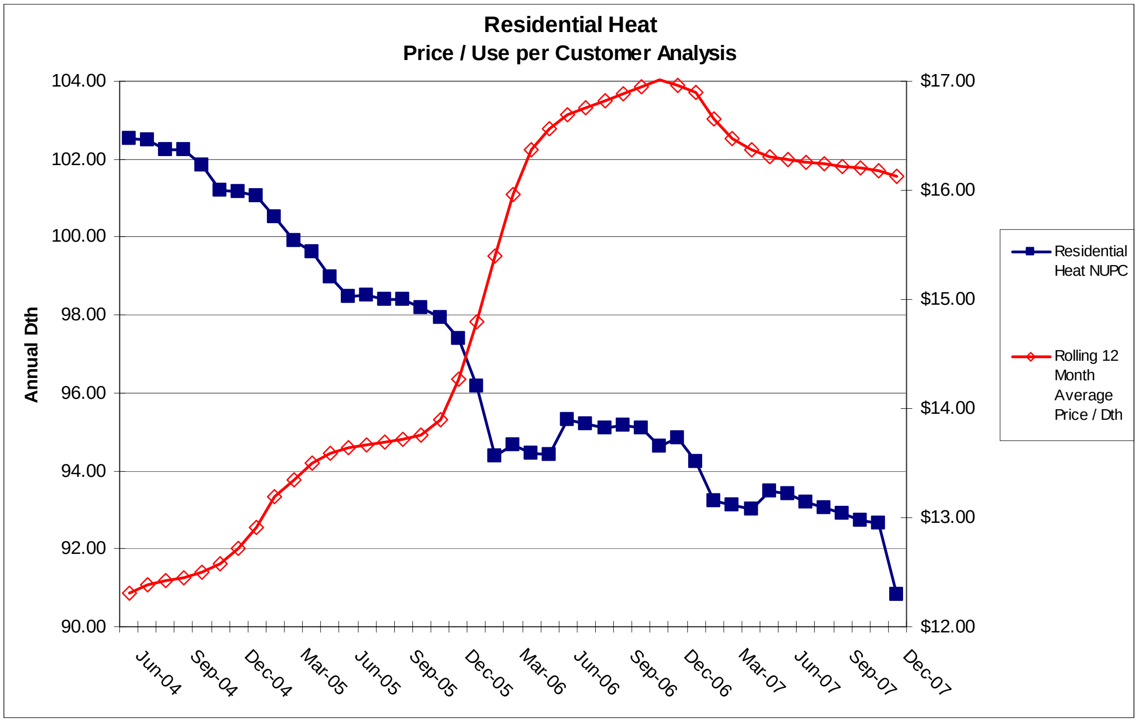
Line		Date	New Standard	Action Taken
	Water Heaters			
1		1990	0.62	Established Energy Factor standard for water heaters manufactured after 1/1/1990
2		2001	Test Procedures	Established new test procedures
3		2004	0.67	Established Energy Factor standard for water heaters manufactured after 1/20/2004
4	Boilers			
5		1984	Test Procedures	Established new test procedures
6		1992	75	Established Annual Fuel Utilization Efficiency standard for boilers manufactured after 1/1/1992
7		1997	Test Procedures	Established new test procedures
8	Furnaces			
9		1984	Test Procedures	Established new test procedures
10		1992	78	Established Annual Fuel Utilization Efficiency standard for furnaces manufactured after 1/1/1992
11		1997	Test Procedures	Established new test procedures

Notes:

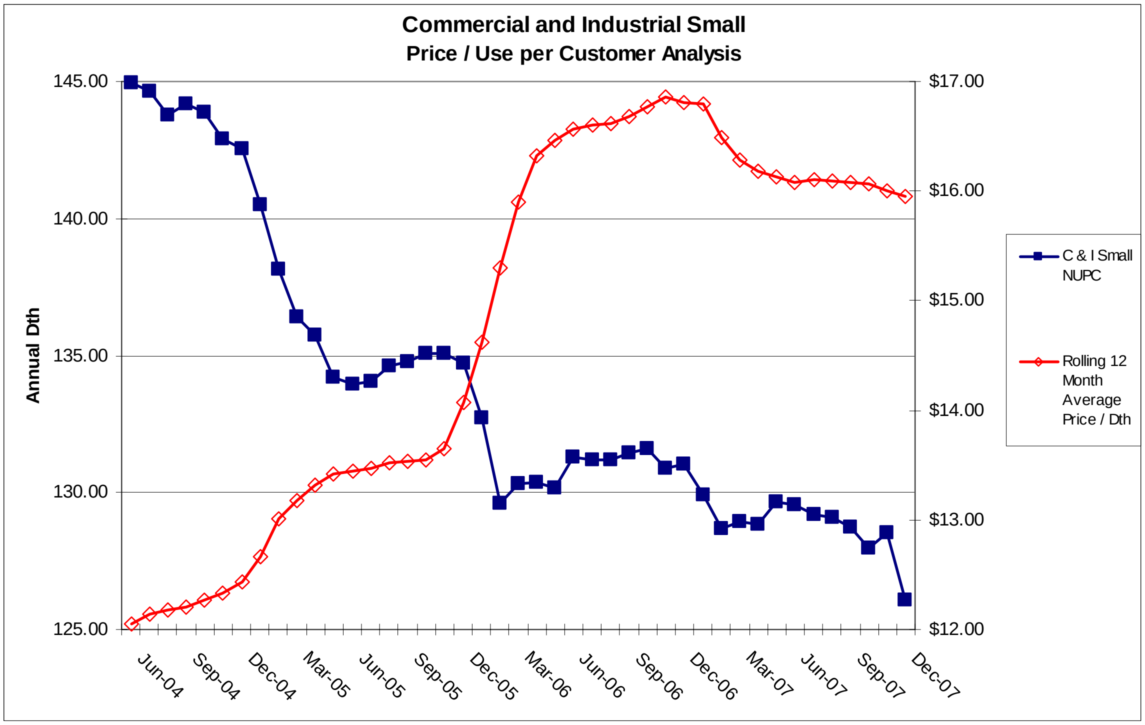
Energy Factor is a standardized measurement of the annual energy efficiency of water heating systems. It is the annual hot water energy delivered to a standard hot water load divided by the total annual purchased hot water energy input in consistent units. The resultant EF value is a percentage. EF is determined by a standardized U.S. Department of Energy (DOE) procedure.

AFUE (Annual Fuel Utilization Efficiency): Measures the amount of fuel converted to space heat in proportion to the amount of fuel entering the furnace. This is commonly expressed as a percentage. A furnace with an AFUE of 90 could be said to be 90% efficient. AFUE includes any input energy required by the pilot light but does not include any electrical energy for fans or pumps.

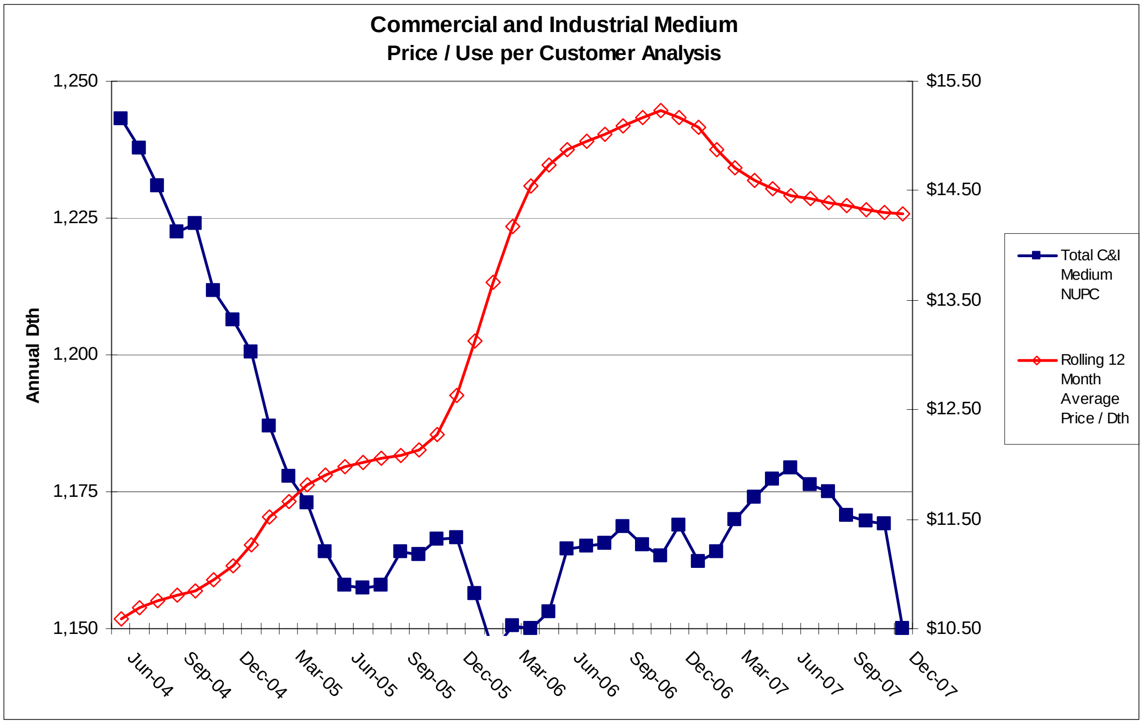
NG-JDS-8


Residential Heat
Price / Use per Customer Analysis
Annual Dth
104.00
102.00
100.00
98.00
96.00
94.00
92.00
90.00
$17.00
$16.00
$15.00
$14.00
$13.00
$12.00
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Residential Heat NUPC
Rolling 12 Month Average Price / Dth

NG-JDS-9


Commercial and Industrial Small
Price / Use per Customer Analysis
Annual Dth
145.00
140.00
135.00
130.00
125.00
$17.00
$16.00
$15.00
$14.00
$13.00
$12.00
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
C & I Small NUPC
Rolling 12 Month Average Price / Dth

NG-JDS-10


Commercial and Industrial Medium
Price / Use per Customer Analysis
Annual Dth
1,250
1,225
1,200
1,175
1,150
$15.50
$14.50
$13.50
$12.50
$11.50
$10.50
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Total C&I Medium NUPC
Rolling 12 Month Average Price / Dth

NG-JDS-11

Patterns in Residential Natural Gas Consumption, 1997 – 2001
American Gas Association, Policy Analysis Group
June 16, 2003

AGA
American Gas Association

Energy Analysis

POLICY ANALYSIS GROUP
400 N. Capitol St., NW
Washington, DC 20001
www.aga.org

EA 2003-01 **June 16, 2003**

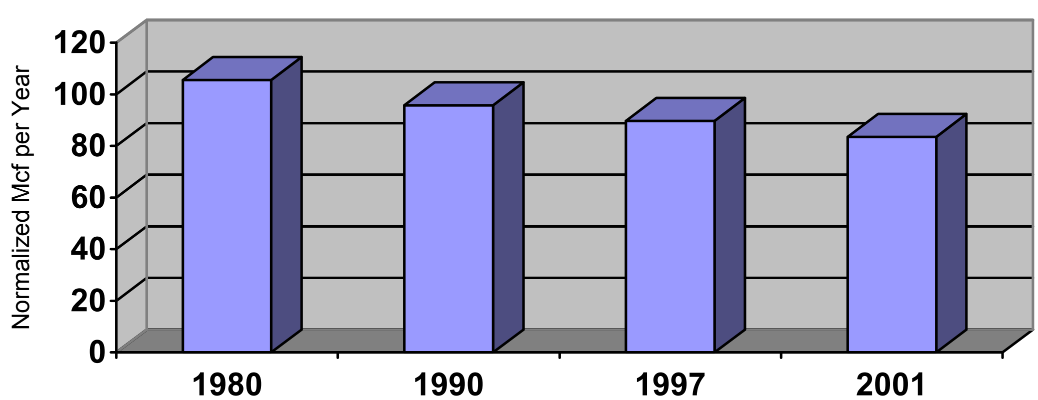
PATTERNS IN RESIDENTIAL NATURAL GAS CONSUMPTION, 1997-2001

I. Introduction

This analysis concludes that natural gas use per residential customer dropped by 6.4 percent from 1997 through 2001. This reduction per customer is in addition to a 16 percent reduction observed from 1980 through 1997. Nationally, natural gas use per residential customer was 106 thousand cubic feet (Mcf) per year in 1980, 89 Mcf per year in 1997, and 83 Mcf per year in 2001 (Chart 1). A previous AGA analysis[1] quantified the primary factors contributing to this decline on both a national and a regional basis and those same factors are again analyzed herein for the more recent period. It should be noted that all data in these analyses have been adjusted to reflect normal weather.

Chart 1

Use Per Residential Customer



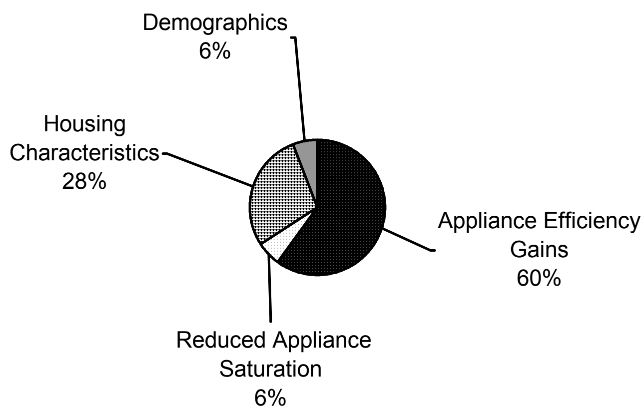
[1] *Patterns in Residential Natural Gas Consumption Since 1980*, American Gas Association, February 2000

II. Executive Summary

Similar to the findings of the previous analysis, the primary cause of the declining use trend was increasing efficiency of gas appliances, predominately space heaters. Other factors include a reduction in the number of gas appliances in homes served with gas and tighter, more energy efficient homes. Chart 2 shows the estimated proportional impact of the various factors contributing to this decline on a national basis.

Chart 2

Factors Contributing to Declining U.S. Natural Gas Use per Residential Customer 1997-2001



- **Regional variation was observed.** There was a decline in the use per customer in all regions of the country: The Northeast lost 1.74 Mcf/year comparing 1997 to 2001, the South and the West lost 2.17 Mcf/year, and the Midwest 4.31 Mcf/year (Table 1). Graphical representation of some of the factors contributing to these trends can be seen in Chart 3.

- **Space heating efficiency gains** contributed almost half of the residential load loss. In 1997, the average furnace efficiency was estimated to be around 74 percent AFUE, since some furnaces sold before federal regulations set the minimum gas space heating efficiency at 78 percent were still operating. During the study period, some of these less efficient furnaces have been replaced, and by 2001 the current weighted average gas space heating appliance efficiency for all units in place is estimated at roughly 77 percent.

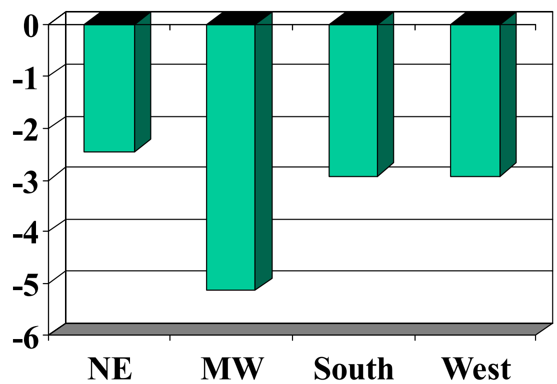
- **Water heating efficiency gains** contributed about 13 percent of the average residential load loss. Federal water heater standards took effect in 1990, setting the minimum gas water heater energy factor (EF) at 0.54, compared to the then-typical 0.5 EF. In addition, consumers are purchasing units with EF ratings higher than 0.54. The 1997 weighted average gas water heating EF is estimated to be slightly less than 0.53, compared to 0.55 in 2001.

Chart 3

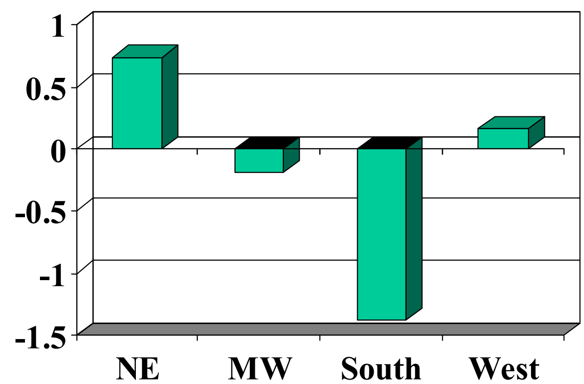
Regional Impact of Major Factors

(Change in Mcf/year per residential customer, 1997 - 2001)

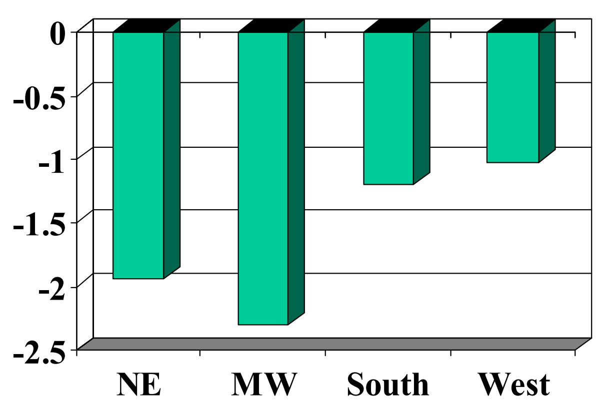
Appliance Efficiency



Appliance Saturation



Housing Characteristics



Note: Contributing factors are calculated independently and may not total to actual change

- **Space heating market share loss** accounted for about two percent of the overall decrease in gas use per residential customer. The proportion of homes with gas service increased since 1997, but the percentage of those gas homes with gas space heat declined slightly. Thus the relative heating base of gas utilities declined.

    - The market share loss in the Midwest and South was two to nine times as great as the national average. In the Northeast and West, however, there was an <u>increase</u> in space heating gas market share (see Chart 2).

- **Baseload appliance market share loss** accounted for about four percent of the residential load loss experienced from 1997-2001. Overall, the number of gas appliances per customer has declined. The market share loss for water heaters, cooking appliances, clothes dryers was relatively small, while gas light market share losses were somewhat higher.

- **Improved home energy efficiency** was responsible for about 29 percent of the decline. Newer homes with improved thermal envelope characteristics, as well as older homes adding insulation and storm windows/doors, reduced the typical amount of gas needed for space heating.

- **Demographic changes** contributed about six percent of the decline in typical residential gas use. Population shifts of gas customers to warmer climates since 1997 accounted for this decline when viewed from a national perspective. Previously quantified factors such as average number of people per residence and number of households setting back their thermostats at night did not change over the study period.

III. Purpose and Data Limitations

This report attempts to provide a broad-based identification and quantification of factors that impacted the average annual natural gas use per residential customer from 1997 to 2001. Most natural gas distribution utilities experienced a slower growth rate in residential demand compared to the growth rate in the number of residential customers during that time period. This trend makes it more difficult for gas companies to achieve expected revenues and to connect new customers economically. This analysis is intended to help companies understand the driving forces behind the declining use trend by updating the previous study.

The results herein estimate the overall impacts of several contributing factors based on national and regional data. Analysis of utility-specific factors could result in conclusions different from those in this report. Individual companies should use this report as a guide in calculating their specific impacts, and they should include factors and influences pertinent to their systems that may not be considered and/or quantified here.

These contributing factors were examined separately. Some of them may have synergistic properties that compound or offset impacts when considered together. The quantification of these factors is not an attempt to determine absolute values for each influence, but rather to indicate the proportional impact that they have on residential use per customer.

Much of the data used in this analysis come from government and AGA surveys. While this information is the best available for national and regional analysis, survey sampling, structure, and/or extrapolation techniques can be flawed, particularly when ascribing results to smaller populations such as states and jurisdictions.

IV. Overview

A previous AGA analysis calculated that normalized use per residential customer declined 16 percent from 1980 to 1997. Since that time, several gas distribution companies have noted a continuation of this trend, with a number of utilities experiencing higher than expected levels of conservation. This analysis updates the previous report, examining the 1997-2001 time frame.

This analysis shows that residential customers are continuing their efforts to reduce natural gas consumption. On a national average basis, natural gas use per residential customer dropped 6.4 percent from 1997 to 2001, from 89.2 Mcf/year to 83.5 Mcf/year. On a regional basis, these impacts varied. For the Northeast, the average gas use per customer decreased about three percent. Residential gas use per customer dropped eight percent for the Midwest, six percent for the South, and four percent for the West.

Table 1
Trends in Residential Natural Gas Use
(Weather Normalized Mcf/Customer/Year)

	1997	2001	Change, 1997-2001
United States	89.2	83.5	-6.4
Northeast	97.1	94.3	-2.9
Midwest	116.4	107.0	-8.1
South	70.2	66.8	-6.2
West	68.3	65.0	-4.2

Residential gas use can be classified as space heating and non-heating. On average, space heating demand accounts for three-quarters of typical gas consumption by residential customers. This demand is very weather sensitive, with use per customer higher in the colder climates than in the warmer regions.

Residential non-heating use of gas is also known as baseload use. This use is typically not very weather sensitive. The primary residential baseload use is for water heating, which accounts for about 86 percent of non-heating demand, based on national averages. The other two primary residential gas appliances are cooking equipment and clothes dryers. Natural gas logs/fireplaces are increasing their market share, and can be used for heating or decorative purposes. Appliances that could also be considered baseload, but have a much lower market penetration, are gas lights, pool heaters, and grills.

V. Contributing Factors

Appliance Efficiency

In response to the energy disruptions of the 1970s, Congress passed the Energy Policy and Conservation Act (EPCA) of 1975. EPCA established an energy conservation program for major household appliances including furnaces, water heaters, refrigerators and freezers, central air conditioners and central air conditioning heat pumps, room air conditioners, dishwashers, clothes washers, clothes dryers, direct heating equipment, pool heaters, kitchen ranges and ovens, fluorescent lamp ballasts, and television sets. The Energy Policy and Conservation Act (EPACT) of 1978 expanded the coverage of EPCA to include commercial building heating and air conditioning equipment, water heaters, certain incandescent and fluorescent lamps, distribution transformers, and electric motors. In 1987, the National Appliance Energy Conservation Act (NAECA), which also incorporates EPCA and EPACT, authorizes the U. S. Department of Energy (DOE) to set energy efficiency standards for major home appliances according to a statutory time schedule stretching into the next century.

DOE's Office of Codes and Standards sets the minimum efficiency ratings of many residential appliances. DOE has set standards for such natural gas appliances as space heaters, water heaters, ovens, and ranges.

Furnaces

During the 1970's natural gas furnaces averaged about 65 percent annual fuel utilization efficiency (AFUE). As interest in more energy efficient appliances increased, the average AFUE for new furnaces increased. DOE, through authority granted by NAECA, set 78 percent AFUE as a minimum for gas furnaces manufactured after January 1, 1992. Furnaces with AFUE ratings up to the mid-90's are available to consumers, and the average AFUE of new residential furnace shipments is currently in the mid-eighties. As the higher efficiency furnaces have worked their way into the residential market in new homes and replacement units, the average AFUE for all residential natural gas furnaces has increased from 65 percent in 1980 to 74 percent in 1997, and to 77 percent by 2001.

Table 2
Residential Natural Gas Furnace Average AFUE
(Percent)

	1980	1997	2001
New Furnace Shipments	66%	85%	86%
All Furnaces In Place	65%	74%	77%

Source for shipment information: Gas Appliance Manufacturers Association

Improvement in overall furnace efficiency caused gas space heating use per customer to fall four percent. However, the impact in terms of sales volume varied by region due to the weather differences. Overall, use per residential customer dropped about 2.7 thousand cubic feet (Mcf) per year from 1997 to 2001, with regional impacts ranging from 1.7 Mcf in the Northeast to 4.3 Mcf in the Midwest, due to the improved furnace efficiency.

Table 3
Impact of Gas Space Heating Efficiency Gains on Use per Customer
(Weather-normalized Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer
	1997	**2001**
United States	61.2	2.7
Northeast	69.8	1.7
Midwest	87.2	4.3
South	44.5	2.2
West	39.1	2.2

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance
Note: Assumes national average furnace efficiency for all regions.

Water Heaters

DOE set the minimum efficiency of natural gas water heater at 0.54 energy factor (EF) for units manufactured after 1989. Starting in 2004, the minimum efficiency will rise to 0.59 EF. Previously, water heaters averaged about 0.5 EF. Industry analysts estimated that the availability of even higher efficiency units raised the average EF of new units sold to 0.57 by the 2001. Based on shipment data and typical retirement rates, the average EF of water heaters went from 0.53 in 1997 to 0.55 in 2001.

Table 4
Residential Natural Gas Water Heater Average EF
(Percent)

	1980	**1997**	**2001**
New Water Heater Shipments	50%	53%	57%
All Water Heaters In Place	50%	53%	55%

Since the average water heater EF improved slightly less than four percent from 1997, the typical consumption by residential customers that have water heaters declined in the same proportion. The average decline was 0.8 Mcf per customer, with regions not varying much from that average.

Table 5
Impact of Gas Water Heating Efficiency Gains on Use per Customer
(Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer
	1997	**2001**
United States	23.9	0.8
Northeast	22.3	0.7
Midwest	25.6	0.8
South	23.5	0.8
West	23.3	0.8

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

<u>Appliance Saturation</u>

The most common natural gas appliances found in homes are space heaters, water heaters, cooking equipment, clothes dryers, and, to a lesser extent, outdoor lights. All of these applications face competition from other energy forms, particularly electricity. Since 1997 the average number of gas appliances found in homes has dropped. This trend, discussed below, contributes to the decline in gas use per residential customer.

Space Heaters

The percentage of gas customers that use natural gas as their main space heating fuel declined by 0.2 percentage points over the four year period. Regionally, the Northeast and West regions saw an increase in this market penetration among its customers. The Midwest loss mirrored the national average. The South region exhibited significant declines in the proportion of their customers that use gas for their main space heating fuel. A primary contributing factor to this decline is the increasing popularity of the heat pump during this time. Not only did heat pumps make significant inroads into new construction (particularly in multi-family housing), electric utilities encouraged existing gas customers to add on heat pumps and use their gas furnaces as back-up systems.

Table 6
Natural Gas Space Heating Appliance Market Penetration
(Percent of all gas customers)

	1997	**2001**
United States	84.4%	84.2%
Northeast	71.7%	72.8%
Midwest	93.8%	93.5%
South	83.9%	81.5%
West	84.1%	85.0%

Source: <u>American Housing Survey</u>, Bureau of the Census, various years

Since the overall change for gas space heating market penetration was not substantial, it caused a decrease in heating use of less than one percent for the average U.S. gas customer. This was also true for the typical Midwest gas customer. The Northeast gas utilities experienced a gain of more than 1.1 percent in heating use per customer due to increased market penetration for space heating. The West region experienced increasing space heating demand per customer of one percent due to the increase in market penetration. The South region's use per customer decreased 2.5 percent due to reduced space heating penetration.

Table 7
Impact of Gas Space Heating Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Space Heating Use per Customer	Change in Weighted Average Space Heating Use per Customer
	1997	**2001**
United States	61.2	-0.1
Northeast	69.8	+0.8
Midwest	87.2	-0.2
South	44.5	-1.1
West	39.1	+0.4

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Water Heaters

Water heaters contribute significantly to a utility's load profile. Demand by these appliances is relatively non-weather sensitive, allowing for optimal utilization of utility investment. Also, these appliances can use as much gas as a furnace in some regions. Therefore, any loss in market penetration or improvements in efficiency will impact noticeably on average use per customer.

In most areas, market penetration of gas water heaters changed marginally between 1997 and 2001. Overall, penetration declined slightly. Regionally, the Northeast's, South's and West's market penetration decreased, with the Midwest increasing somewhat.

Table 8
Natural Gas Water Heater Market Penetration
(Percent of all gas customers)

	1997	**2001**
United States	84.2%	84.0%
Northeast	77.9%	77.8%
Midwest	86.2%	86.6%
South	79.0%	78.3%
West	91.9%	91.2%

Source; American Housing Survey, Bureau of the Census, various years

When the proportion of gas customers with gas water heaters declines, the weighted average gas use per customer declines. For example, the national average penetration of water heaters fell 0.2 percentage points from 1997 to 2001, resulting in a decline in overall gas use per customer of 0.05 Mcf/year. The South and West regions' losses averaged about 0.16 Mcf/year, while the Northeast region loss was minor, 0.02

Mcf/year. Conversely, a slight increase in penetration in the Midwest led to a 0.1 Mcf/year increase.

Table 9
Impact of Gas Water Heater Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Water Heating Use per Customer	Change in Weighted Average Water Heating Use per Customer
	1997	**2001**
United States	22.7	-0.05
Northeast	19.9	-0.02
Midwest	22.2	+0.10
South	20.4	-0.17
West	23.7	-0.16

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Cooking

The percentage of gas customers that cook with gas declined in all regions but the West, due to electric products dominating the new home market, even those homes with gas service, as well as replacing old gas units. Nationally, cooking market penetration for gas customers fell 2.6 percent, with the Northeast falling 1.3 percent, the Midwest 5.0 percent, and the South 4.0 percent. The West increased slightly.

Table 10
Natural Gas Cooking Appliance Market Penetration
(Percent of all gas customers)

	1997	**2001**
United States	58.6%	57.1%
Northeast	77.2%	76.2%
Midwest	52.4%	49.8%
South	53.0%	50.9%
West	56.6%	56.8%

Source: American Housing Survey, Bureau of the Census, various years

Despite the significance of the decline for gas cooking penetration, the resulting impact is relatively small. This is due to the smaller proportion of gas customers with this appliance combined with the modest annual energy consumption from these units. For all regions, the change amounted to less than 0.11 Mcf annually.

Table 11
Impact of Gas Cooking Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Cooking Use per Customer	Change in Weighted Average Cooking Use per Customer
	1997	**2001**
United States	2.5	-0.06
Northeast	3.2	-0.04
Midwest	2.2	-0.11
South	2.2	-0.09
West	2.4	+0.01

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Clothes Dryers

Penetration of gas dryers increased slightly in all regions but the South (four percent decline) from 1997 to 2001, ranging from one percent in the Northeast to six percent in the West.

Table 12
Natural Gas Clothes Dryer Market Penetration
(Percent of all gas customers)

	1997	**2001**
United States	27.0%	27.5%
Northeast	29.4%	29.7%
Midwest	32.6%	33.4%
South	16.0%	15.4%
West	29.0%	30.7%

Source: American Housing Survey, Bureau of the Census, various years

These changes in penetration for gas clothes dryers resulted in marginal changes in typical use per customer, less than one-tenth Mcf in the regions.

Table 13
Impact of Gas Drying Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Drying Use per Customer	Change in Weighted Average Drying Use per Customer
	1997	**2001**
United States	1.1	+0.02
Northeast	1.3	+0.01
Midwest	1.3	+0.03
South	0.7	-0.03
West	1.3	+0.07

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Outdoor Gas Lights

Natural gas lights were somewhat popular with customers the through mid-1970s. During the turmoil in the energy markets in the late-70s, President Carter encouraged people to turn their gas lights off or convert them to electricity. Since that time, their market share for gas customers fell significantly. The decline continued from 1997 (1.5 percent market penetration among gas customers) through 2001 (0.8 percent). Assuming typical gas light usage of 19 Mcf per year, the decline in market share caused the weighted average gas use per residential customer to decline about one-tenth Mcf per year on a national average. No data were available for regional comparisons.

<u>Housing Characteristics</u>

Thermal Efficiency

Homes across the country have become more energy efficient due, in part, to the improved thermal efficiency of the building envelope. New homes, which must meet local regulations implemented over the last two decades regarding thermal efficiency, account for most of this improvement. In addition, many homeowners have retrofitted older residences in order to cut their energy bills.

According to estimates from the U. S. Department of Energy's Energy Information Administration,[2] the average residential building was three percent more efficient in 2001 compared to the 1997 average. This improvement in thermal efficiency reduced the heating demand from the residential sector. Overall, typical consumption decreased by about 1.6 Mcf nationally. Regionally, the decrease in weighted average gas use per customer ranged from about one Mcf in the West to more than two Mcf in the West.

Table 14
Impact of Improving Home Thermal Efficiency on Gas Demand
(Decrease in Mcf per Residential Customer per Year)

United States	1.63
Northeast	1.94
Midwest	2.30
South	1.20
West	1.02

<u>Other</u>

Geographic Population Shifts

From 1997 to 2001, population growth, and subsequently gas customer growth, was greater in the warmer regions (South and West) than in the colder regions (Northeast and Midwest). About 51 percent of the residential gas customers were in the warmer Southern and Western sections of the country in 1997, compared to 52 percent in 2001. With more of the households in warmer climates, the average heating demand,

[2] <u>Annual Energy Outlook</u>, Energy Information Administration, various years.

on a national basis, declined. This larger percentage of gas customers in warmer climates resulted in overall use per gas customer falling about 0.33 Mcf on a national basis. This factor does not impact typical regional use per gas customer.

Table 15
Regional Natural Gas Customer Population Trends
(Percent of all gas customers)

	1997	2001
United States	100.0%	100.0%
Northeast	19.2%	18.9%
Midwest	29.7%	28.9%
South	26.9%	28.0%
West	24.2%	24.3%

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Other Factors

Several factors did not change substantially between 1997 and 2001, and therefore should not have measurably impacted use per customer. The table below shows national factors for such items as thermostat settings for each of the years.

Table 16
Natural Gas Customer Characteristics

	1997	2001
Age of Home	33.1 years	34.6 years
Age of Furnace	13.8 years	13.6 years
Avg. Winter Day Temp	70.2 degrees	70.2 degrees
Avg. Winter Night Temp	67.8 degrees	68.0 degrees
Setback Temp Day	45% do	49% do
Setback Temp Night	47% do	47% do
Avg. Persons per Home	2.64	2.61

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Other Factors Not Quantified

Other factors could have an impact on residential natural gas use, but were not quantified here, primarily due to lack of data. For the most part, these should have impacts less than most of those factors listed above. Some of these factors include:

Water Conservation – Low flow showerheads and increasingly efficient dishwashers and washing machines have decreased the amount of hot water needed per residence.
Economic Influences – Changes in the price of natural gas and in the general economic condition of the general population influence consumption.
Environmental Regulations – Restrictions on certain combustion practices, such as wood fireplaces, may impact consumer purchases of gas products.
Gas Hearth Products – Gas fireplace/logs have become more popular over the past few years, but it is not clear whether these units actually add to load. Some units could displace gas furnace requirements.

Unoccupied/Seasonal Homes – The rise in second home ownership combined with increasing vacancy rates for rental homes could reduce overall use per customer.

VI. National & Regional Summaries

Table 17 summarizes the factors contributing to the decline in use per residential customer. The sum of the estimated factors closely approximates the observed decline for the United States. Regional comparisons do not provide as close a fit. Keep in mind that this report provides a broad-based assessment to the factors contributing to the decline in order to provide an understanding of the relative impact from each of these factors. This report does not attempt to provide precise measures of these factors due to limitations in the data.

Table 17
Summary of Factor Quantification and Comparison to Actual Decline
(Change in use per residential customer, 1997-2001 Mcf/year)

	U.S	NE	MW	South	West
Space Heating Efficiency	-2.68	-1.74	-4.31	-2.17	-2.17
Baseload Appliance Efficiency	-0.77	-0.71	-0.82	-0.75	-0.75
Space Heating Market Penetration	-0.12	+0.79	-0.22	-1.09	+0.38
Baseload Appliance Market Penetration	-0.22	-0.05	+0.03	-0.29	-0.08
Thermal Efficiency Gains	-1.63	-1.94	-2.30	-1.20	-1.02
Population Trends	-0.33	N/A	N/A	N/A	N/A
Total	-5.75	-3.65	-7.62	-5.50	-3.64
Actual Change	-5.71	-2.83	-9.39	-4.40	-2.86
Difference**	-0.04	-0.82	1.77	-1.10	-0.78

*** Can be due to a variety of factors, including data error, omission of other factors, and imprecise methodology*

IX. Methodology

<u>Normalized Use Per Customer</u>

- Calculate actual use per residential customer from EIA data[3]
- Determine heating portion of use based on AGA survey data[4]
- Determine weather normalization factor by dividing the 30-year (1961-1990) normal heating degree days into the actual degree days, based on NOAA data[5]
- Divide heating portion by weather normalization factor, and add back in non-heating load

[3] <u>Natural Gas Annual</u>, various years, Energy Information Administration, U.S. Department of Energy, Washington, DC.
[4] <u>Residential Natural Gas Market Survey</u>, various years, American Gas Association, Washington, DC.
[5] <u>State, Regional, and National Monthly and Seasonal Heating Degree Days</u>, various years, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, Washington, DC.

Average Space Heating AFUE

- Assume 65% AFUE as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas space heating customers from current year's, based on trend analysis of EIA RECS data[6]
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data[7]
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace AFUE for all existing units based on average AFUE of shipments as provided by GAMA

Space Heating Efficiency Impact

- Calculate average use per customer by multiplying the normalized heating load by the percent of gas customers with gas space heating (based on EIA RECS data)
- Calculate change in average furnace AFUE by dividing 1997 AFUE value into the selected year's AFUE value
- Calculate the efficiency-adjusted demand by dividing the 1997 average use per customer by the change in average furnace AFUE for the selected year
- Subtract the efficiency-adjusted demand from the 1997 average use per customer to determine impact

Average Water Heating EF

- Assume 0.50 EF as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas water heating customers from current year's, based on trend analysis of EIA RECS data
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace EF for all existing units based on average EF of shipments estimated at 0.54 EF to 0.56 EF

Water Heating Efficiency Impact

- Calculate average use per customer by multiplying the water heating load (based on AGA survey data) by the percent of gas customers with gas water heating (based on EIA RECS data)
- Calculate change in average EF by dividing 1997 EF value into the selected year's EF value
- Calculate the efficiency-adjusted demand by dividing the 1997 average use per customer by the change in average water heater EF for the selected year
- Subtract the efficiency-adjusted demand from the 1997 average use per customer to determine impact

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[6] RECS: Housing Characteristics, various years, Energy Information Administration, U. S. Department of Energy, Washington, DC.

[7] GAMA News, various years, Gas Appliance Manufacturers Association, Arlington, VA.

Appliance Market Penetration Impact

- Calculate appliance penetration by dividing the number of residences with gas service by the number of customers with that appliance, based on EIA RECS data
- Subtract the impact year penetration from the 1997 penetration to determine the change in market penetration
- Calculate the weighted average gas use per customer for that appliance by multiplying the penetration value times the typical gas use for that appliance
- Multiply the change in market penetration by the 1997 weighted average use of that appliance to determine the reduction in weighted average use per customer for that appliance

Thermal Efficiency Impact

- Obtain an estimate of average percent increase thermal home efficiency enhancements from current and past EIA forecasts[8]
- Multiply the thermal efficiency percent increase by the percent difference in heating load and by the percent of gas homes with gas space heating to determine the thermal efficiency impacts

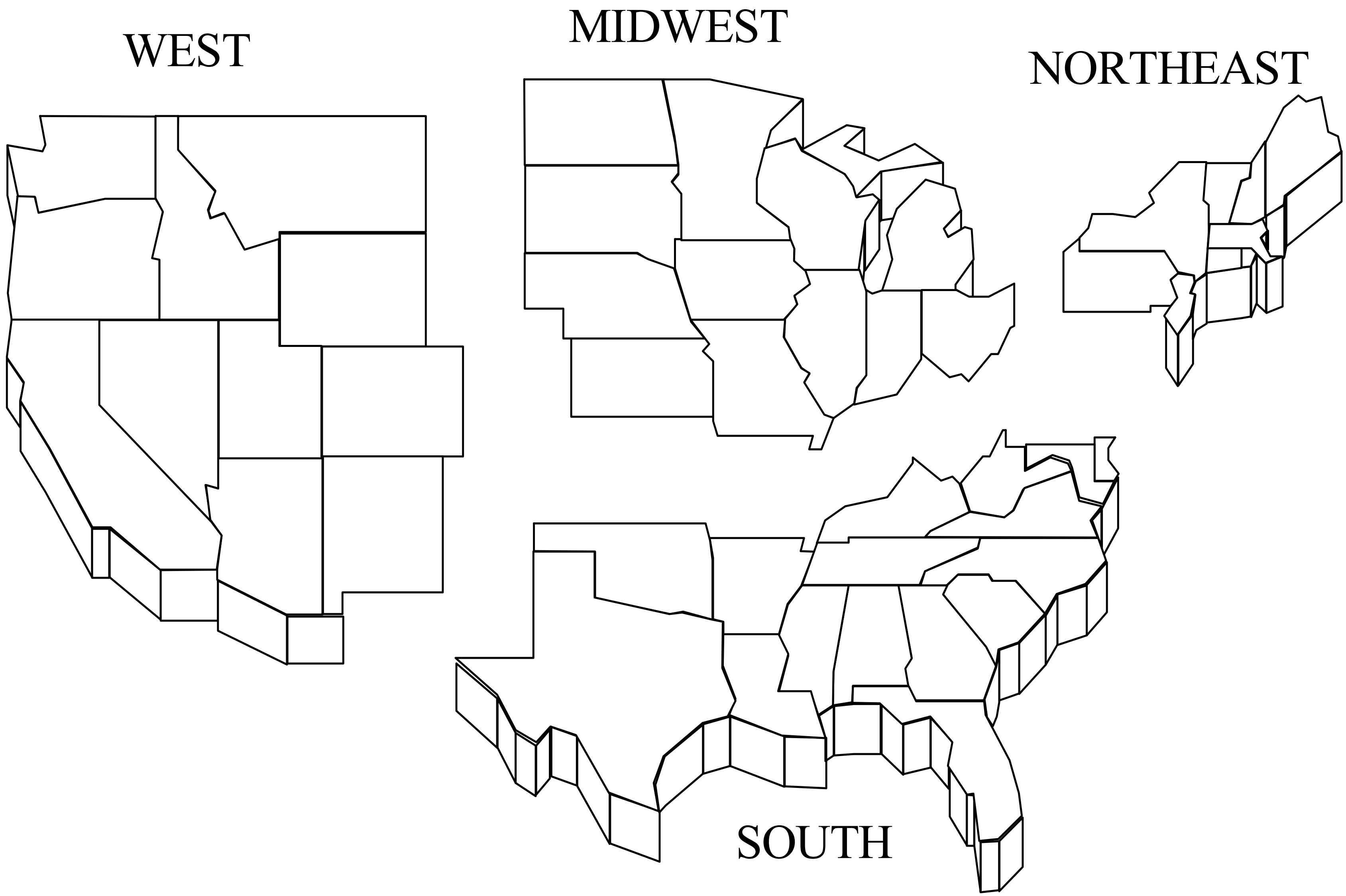
Population Shift Impact

- Determine the percent of gas customers by region for 1997 and 2001 from EIA RECS data
- Determine the normalized heating demand for those regions in 1997 based on AGA survey data
- Apply those same regional demand figures to the 2001 regional population distribution, calculate the weighted average national numbers for both, and compare the two numbers

[8] *Annual Energy Outlook*, various years, Energy Information Administration, Washington, DC.

Appendix

US Census Regions



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Executive Summary

Introduction and Key Findings

The consumption of natural gas per household has been declining, on a weather-normalized basis, since about 1980. Over time, natural gas consumers have been tightening their homes, purchasing more efficient appliances and turning down their thermostats. Given the significant increase in natural gas prices since 2000, the American Gas Association (AGA) decided to examine whether or not the trend in declining use has changed in this higher-priced environment. The results of this study are based on monthly data submitted by 46 local natural gas distribution companies that serve nearly 30 percent of all residential natural gas customers throughout the U.S. Some companies submitted data as far back as the early 1980's. The key findings of the study are as follows.

- A trend in declining use per residential natural gas customer of 1 percent annually has been documented[2] back to 1980. This decline rate has accelerated since the year 2000.
  - Weather-adjusted use per residential customer fell by 13.1 percent from 2000 through 2006.
  - The annual rate of decline in this 2000 to 2006 timeframe more than doubled relative to the pre-2000 period, increasing to 2.2 percent annually.
  - Further acceleration was witnessed in the 2004 to 2006 period, as evidenced by a 4.9 percent annual rate of decline.
  - The decline in use per customer has accelerated since 2000 in all 9 geographic regions analyzed.

- No appreciable changes in the price elasticity of demand were observed post-2000. Price elasticity of demand refers to the percentage change in demand for a good relative to a percentage change in price. Although the elasticity has not changed over time, it should be noted that natural gas is an essential product that provides heat, hot water and cooking. Despite the essential nature of natural gas, consumers have continued to reduce their consumption at a relatively constant rate with respect to changing prices. Therefore, the large price increases post-2000 have resulted in the large consumption declines noted above.
  - This study found a short-run price elasticity of –0.09 and a long-run price elasticity of -0.18. (Long-run elasticity refers to a period of time long enough for consumers to change the capital stock of their energy consuming equipment and the shell efficiency of their homes.)

[2] 2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001.

- These price elasticity estimates are relatively consistent with previous works on this subject.
- The econometric analysis presented in this study predicts a decline of 13.9 percent between 2000 and 2006; the actual decline was 13.1 percent. The decline is attributable to a price effect and the longer-run trend towards tighter homes and more efficient appliances. The price elasticity effect is 7.9 percent - equal to the elasticity estimate of -0.18 times the 44 percent real price increase. The remaining 6.0 percent is explained by the longer-run trend towards tighter homes and more efficient appliances.
- As a general rule of thumb, at the national level we would expect a 10 percent increase in the price of natural gas to result in nearly a 3 percent decline in the average residential use per customer 12 months later – 1 percent attributable to more conservation with existing appliances, 1 percent attributable to the price-induced purchase of more efficient appliances, and 1 percent attributable to the natural turnover of equipment that occurs annually.

Background

Residential natural gas consumption is strongly influenced by three factors: seasonal heating needs; response to price change; and the efficiency changes in appliances and home shells caused by a natural turnover rate to more efficient homes and gas appliances. On a weather-adjusted basis, the price and the long run conservation effects are key determinants of changes in residential natural gas consumption. The price effects can be further decomposed into short-term and long-term effects. Short term effects are decisions made by consumers with the current capital stock. Residential customers "turning down the thermostat" would be considered a short term effect. Long term effects are distinguished from short term effects by the inclusion of the decision to purchase more efficient energy consuming appliances and prematurely retiring less efficient ones. The price elasticity in the long-run is the sum of (1) the short-run demand and (2) the additional changes that occur to quantity demanded one year later because of natural gas price effects on the efficiency of the appliance capital stock and on the shell efficiency of homes[3]. While the separate efficiency and conservation effects due to appliance and housing shell turnover are difficult to disentangle in the current sample, they do appear to be discernable from the long term price effects.

To address these issues, AGA commissioned a study to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. Other objectives of this study were: to obtain updated elasticity estimates for all nine US Census Regions and for the US; to test for an increase in

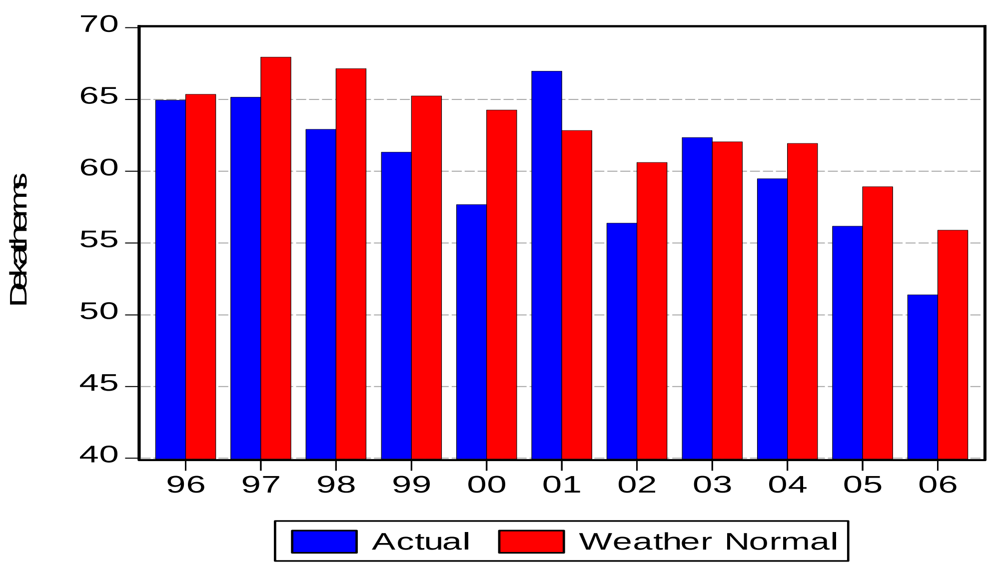
[3] It should be noted that if natural gas prices decrease, consumers will not replace recently purchased efficient equipment with less efficient equipment. So there maybe asymmetry with respect to the impact of natural gas prices on appliance and shell efficiency. The efficiency gains in appliance equipment that have occurred in the last several years will not disappear if natural gas prices go down. However, declining prices may lead consumers turning up thermostats to increase comfort levels (in the short-run). In the very long-run, a decline in prices could lead to an increase in burner tips per customer.

the price elasticity of demand for natural gas since the year 2000; and to estimate a natural rate of decline in use per customer due to technology-induced gains in appliance and shell efficiency and a change in conservation attitudes that would occur even in an environment of constant real natural gas prices.

Decline in Use per Customer

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has accelerated. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent nationally between 2000 and 2006 for the sample of companies analyzed in this report. Figure ES1 below shows the winter season use per customer in actual and weather normal dekatherms from 1996-2006 using the data collected by AGA.[4] It is clear that actual and weather normalized use per customer has been declining since 1997 and this decline has accelerated since 2004.

Figure ES1
US Annual Winter Use per Customer



[4] The data was collected from 46 Local Distribution Companies (LDCs) in 29 states, representing 28 percent of all residential customers. An LDC is a gas utility that serves a specific rate jurisdiction. Some of the companies in this sample have multiple jurisdictions in their corporate structure. The winter season for this report is defined as the sum of the monthly consumption between October and March.

Table ES1 disaggregates the national winter season weather normal use per residential customer across the nine US Census Regions and for the US. The decline in weather normal use per customer has occurred across all US Census regions. The decline ranges from 5.7 dekatherms per customer for the West South Central region to 10.9 dekatherms for the East North Central region. The percentage decline in use per customer ranged from 9.2 percent for the Middle Atlantic Region to 14.8 percent for the Pacific Region.

Table ES1
Annual Winter Season Weather Normal
Natural Gas Use per Residential Customer,
By Region and for the U.S.
(Dekatherms per Customer)

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

Source: An Economic Analysis of Consumer Response to Natural Gas Prices, AGA, 2007.

Price Elasticity and “Natural” Conservation Estimates

This study found that neither a practical nor statistically significant change in the price elasticity of residential natural gas consumption occurred in the post year 2000 period. The price elasticity of residential natural gas demand appears to have remained relatively constant since the 1990s. This implies the large percentage price increase since 2000 accounted for the decline in natural gas use, rather than an increased sensitivity or greater response by households to a given price change. The study also found that independent of natural gas price increases, the naturally occurring decline due to the technology driven gain in appliance and home thermal shell efficiency, as well as changes in conservation attitudes was 1 percent per year.

Table ES2 illustrates that for the sample of companies in the study, the short run price elasticity of demand averaged -0.09, while the long run estimated averaged -0.18. Therefore, given a 10 percent increase in the price of natural gas, consumption would decline 2.8 percent; 1.8 percent for price response, added to 1.0 percent decline due to the normal turnover of appliances and other “natural” conservation measures. There is very little regional variation in the total impact of a 10 percent increase in real prices on use per customer. The impact in all regions was close to the national estimate of 2.8 percent, with the Mountain region being the lowest at 1.9 percent and the South Atlantic region being the highest at 3.7 percent.

The study also found that the elasticity estimates calculated using the sample data were generally consistent with the elasticity estimates found in the energy economics literature.[5]

Table ES2
Summary of National and Regional
Natural Gas Price Elasticity Estimates*

Region	Short-run elasticity	Long-run elasticity**	Annual Time Trend	Total Response to a 10% Price Increase***
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

* Estimates obtained from the "fixed effects" pooled regression
** Cumulative: includes impacts of short-run elasticities
*** The total response to a 10% price increase is the sum of the long-run elasticity and the annual time trend effect.

<u>Implications</u>

These price elasticity estimates and the natural conservation trends are able to explain the post 2000 winter consumption per household per customer actual experience.

Between 2000 and 2006, real natural gas prices for the sample companies in this study rose 44 percent, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to

[5] See Appendix C of the main report for a summary of the elasticity estimates found in the energy economics literature.

newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

$$\begin{array}{lcccc} \textit{Overall decline} & & \textit{Price Effect} & & \textit{Conservation and} \\ \textit{in Winter Gas Use} & = & \textit{Elasticity with} & + & \textit{Turnover to More} \\ \textit{per Customer} & & \textit{Price Increase} & & \textit{Efficient Appliances} \\ 13.9\% & = & 0.18 \; x \; 44\% & + & 6 \; x \; 1.0\% \\ & = & 7.9\% & + & 6.0\% \end{array}$$

In the expression above, the left hand term is the overall predicted decline of winter gas use per customer, the first term on the right hand side is the price effect reflecting the elasticity estimate multiplied by the price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

The results from analyzing the AGA sample data lead to a general rule of thumb. This rule does not apply to all companies in all situations, but the general rule with its caveats provides valuable insight to the underlying processes governing consumer behavior. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across both the LDCs and Census regions. Twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer on a national level. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by replacing still functional appliances with more efficient units, and about a 1 percent drop in gas usage per customer due to the natural turnover of old gas appliances to the more efficient gas appliances that are available in the market each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

Other factors that impacts residential energy use are the many programs that encourage consumers to save energy. These include:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for the purchase of efficient appliances and housing shell improvements, and consumer education on the importance of saving energy.
- State and local governments also encourage efficiency through similar programs.
- Many utilities provide rebates, incentives, and assistance to their customers to conserve energy use. For example, electric and natural gas utilities provided more than $140 million in 2005 to assist low-income customers to weatherize their homes.[6]

[6] Source: http://liheap.ncat.org/tables/FY2005/05stlvtb.htm

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following year. This is driven by the historical forces related to the natural turnover of old appliances to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in thermal shell efficiency from new construction will result in continued conservation, impacting utility operations. Third, even if future natural gas prices remain constant or even decrease, the appliance and house shell efficiency gains achieved in prior years will not be reversed.

Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from natural gas companies that did not participate in the initial study.
- Try different specifications of the model.
- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.
- Consider the impact of competition from the electric utility industry.

Introduction

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has increased. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 for the sample of companies analyzed in this report.

It is important from a budgeting point of view for Local Distribution Companies (LDCs) to understand the cause of this decline. Was it caused by the recent increases in natural gas prices and customer's response to these price increases? Did customers change their behavior in response to these price increases? Have they become more sensitive to natural gas price movements or has the price induced response behavior remained relatively the same over time? Did customers switch to more efficient gas appliances in response to these natural gas price increases? Is it due to technological innovations which lead to increased efficiencies in appliances and thermal shells of homes? These efficiencies are in some sense passive as older appliances are replaced with more efficient models through natural attrition.

To address these issues, the American Gas Association (AGA) funded a study to re-estimate the price elasticity of natural gas demand by residential households using a sample of data that covers the recent period of large natural gas price increases. The main objective of this study was to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. A second purpose of this study was to test for an increase in the price elasticity[7] of demand for natural gas since the year 2000. A third and equally important purpose of this study was to obtain updated elasticity estimates for all nine US Census Regions and for the US as a whole. Finally, the study attempts to estimate a natural rate of decline in use per customer due to technology induced gains in appliance and shell efficiency that would even occur in an environment of constant real natural gas prices.

There are hundreds of studies on the elasticities of natural gas demand. These studies have generated a range of elasticity estimates. If one goes back to the 1970's and even to the 1960s, these estimates vary over a wide range. Estimates of short-run price elasticity range from as low as –0.05 in Beirlein, Dunn and McConnon (1981) to a high of –0.68 in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates, the range of estimates is even higher, with the low being -0.017 in Hewlett (1977) to a high of –3.42 in Beirlein, Dunn and McConnon (1981). See Dahl and Roman (2004) and Dahl, et. al. (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). See Appendix C for a brief literature review of price elasticity estimates.

[7] The price elasticity of demand is defined as the ratio of the percent change in quantity demanded of a particular good to the percent change in the price of that good, such as natural gas demand in this study.

Many of the studies estimated elasticities of natural gas demand with data aggregated at the state and national level and collected by the States; or collected by the Energy Information Administration (EIA). Examples of these are Balestra and Nerlove (1966), Jaskow and Baughman (1976), Berndt and Watkins (1977), and more recently, Maddala, Trost, Li, and Joutz (1997). Other studies use individual micro data to estimate demand elasticities. Examples of these are Hewlett (1977), Barnes, Gillingham and Hagemann (1982), and Green and Gilbert (1983). While the former studies using state and national aggregate data may provide some useful information at the state and national level, and the latter studies may provide good estimates of individual demand elasticities, neither provide adequate estimates at the individual LDC level of aggregation. Most of these studies do not allow for a natural rate of decline in use per customer due to technologically induced efficiency gains in appliances and thermal shells of homes. In addition, there are few, if any, studies that use current data that includes the recent run-up in natural gas prices. This study will fill these gaps in the literature by using high quality data collected and compiled at the individual LDC level and covering the period as recent as March, 2006.

This paper is divided into the following five sections. In Section 1, background information at the regional, as well as the national level, is provided. The information includes residential natural gas consumption, the declining trend of consumption, and price movements. In Section 2, the database constructed from the survey of LDCs is described. Section 3 explains the mathematical equations used to estimate short- and long-run price elasticity of demand. Empirical results of short-run and long-run elasticity and the declining trend in gas usage are presented in Section 4. The report concludes in Section 5 with a summary of the results and policy implications. In addition, there is a list of suggestions for future research. References and technical appendices can be found at the end of the report. The appendices include construction of the weather-normalized series for use per customer, a map of the Census regions, a brief literature review, and a discussion of statistical hypothesis testing.

Section 1: Background

Residential natural gas consumption per customer in the US has been declining. Figure 1 below shows the winter season use per consumption actual and weather normal (in dekatherms) from 1996 to 2006 using the data collected from the sample LDCs. The winter season for this report is defined as the sum of the monthly consumption between October and March.

Figure 1
US Annual Winter Use per Customer

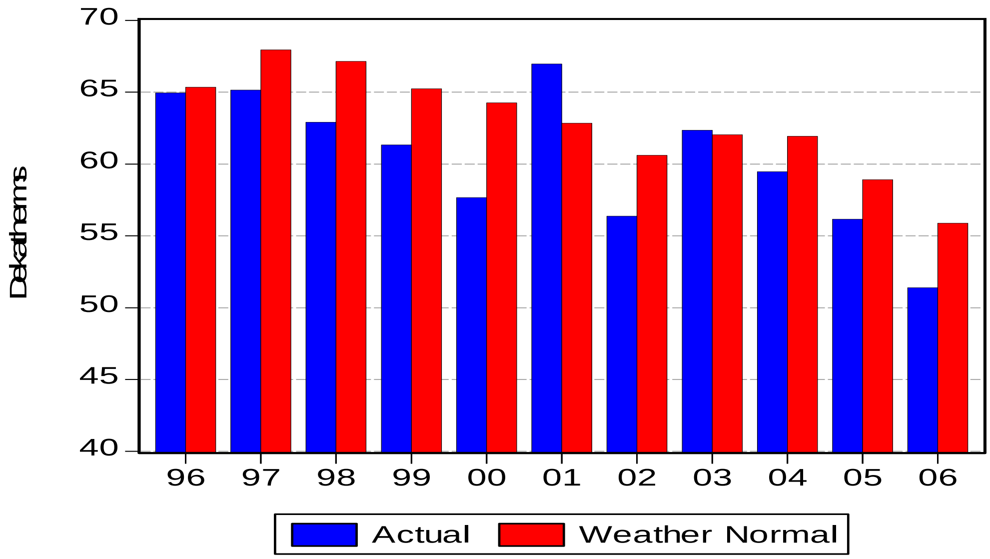


Table 1: US Annual Winter Use per Residential Customer in Dekatherms				
Year	**Actual**		**Winter Normal**	
	Level	**Percent Change**	**Level**	**Percent Change**
1996	64.9		65.3	
1997	65.2	0.5	67.9	4.0
1998	62.9	-3.5	67.1	-1.2
1999	61.3	-2.5	65.2	-2.8
2000	57.7	-5.9	64.3	-1.4
2001	67.0	16.1	62.8	-2.3
2002	56.4	-15.8	60.6	-3.5
2003	62.3	10.5	62.0	2.3
2004	59.5	-4.5	61.9	-0.2
2005	56.2	-5.6	58.9	-4.9
2006	51.4	-8.5	55.9	-5.1
Annual Percent Change 1996-2000		**-1.64**		**-1.48**

As can be seen from Figure 1 and Table 1, there has been a marked decline in weather normal use per customer. The annual percent change from 1996 to 2006 was -1.64 percent and -1.48 percent respectively, for actual and weather normal consumption. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 and by 9.7 percent between 2004 and 2006 for the sample of companies analyzed in this report.

The phenomenon of declining weather normal use per customer is not new[8]. Some even feel it started on February 1, 1977 when then President Jimmy Carter, after only two weeks in office, said in his now famous fireside chat:

"*All of us must learn to waste less energy. Simply by keeping our thermostats, for instance, at 65 degrees in the daytime and 55 degrees at night we could save half the current shortage of natural gas.*"

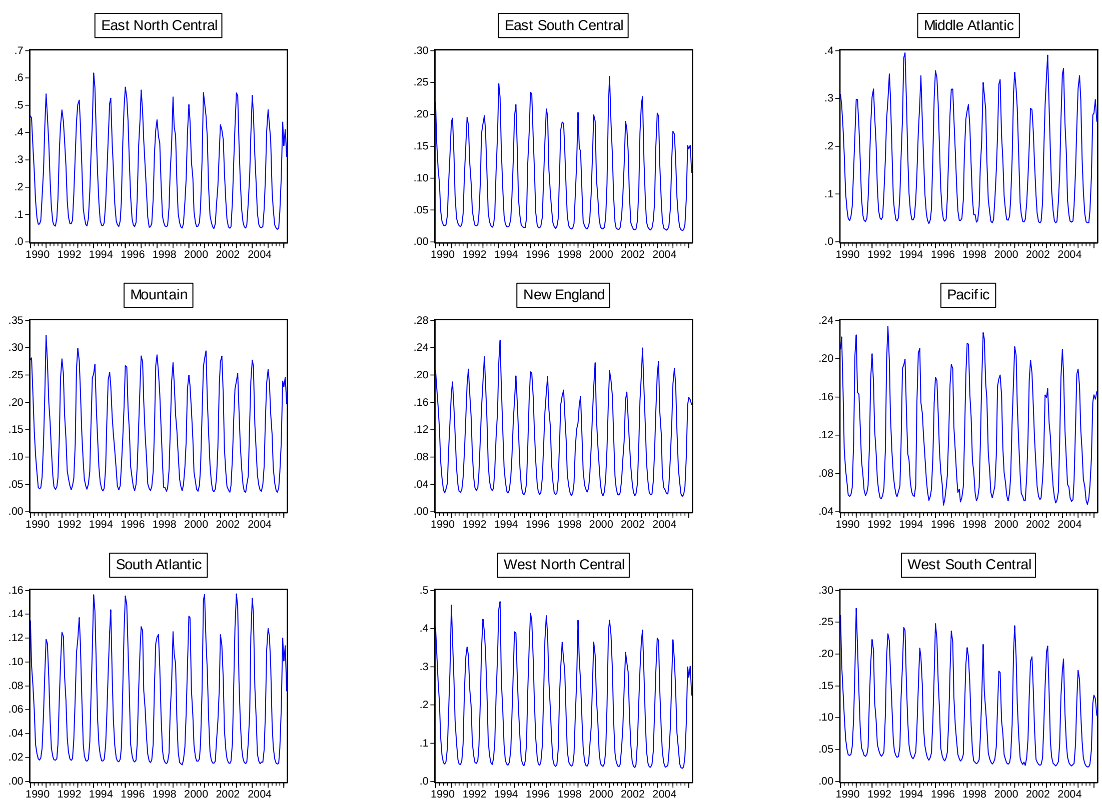
In the years since, the first President Bush established the first National Energy Strategy in June of 1989, and the government has imposed efficiency standards, subsidized technological improvements in both shell and appliance efficiency, and generally encouraged its citizenry to conserve on energy. Efficiency improvements are sure to continue, and if natural gas prices stay high, it will most certainly encourage natural gas

[8] Between 1978 and 1982, energy consumption per household actually decreased by 26%. See EIA's Annual Energy Review, URL http://www.eia.doe.gov/emeu/aer/ep/ep_frame.html.

customers to trade in old inefficient appliances for newer more efficient ones. The impact on the natural gas industry will be an obvious decrease in revenue accruing to natural gas LDC's.

This study will examine the reasons for this decline in use per customer, with particular emphasis on estimating the short-run and long-run price elasticity of natural gas demand since the year 2000. It will also analyze and measure the rate of decline caused by the natural turnover rate of old inefficient appliances with newer more efficient ones. The trends in the AGA sample are validated from trends in other data. The U.S. Energy Information Administration (EIA) reports aggregate estimates of residential consumption in BCF/day and residential prices in \$/MCF on a monthly basis from 1990 to the present. The EIA sample data covers all LDCs in the US. These series are plotted by US Census Region in residential consumption per household per day in Figure 2 and in nominal and real terms in (\$2000)/MCF in Figure 3 below. A map of the US Census Regions is shown in Appendix B. These figures provide a comparison with the subsequent figures from the AGA survey database. They demonstrate that the trends and patterns in the survey are consistent with a recognized national source of data even before adjusting for normal weather.

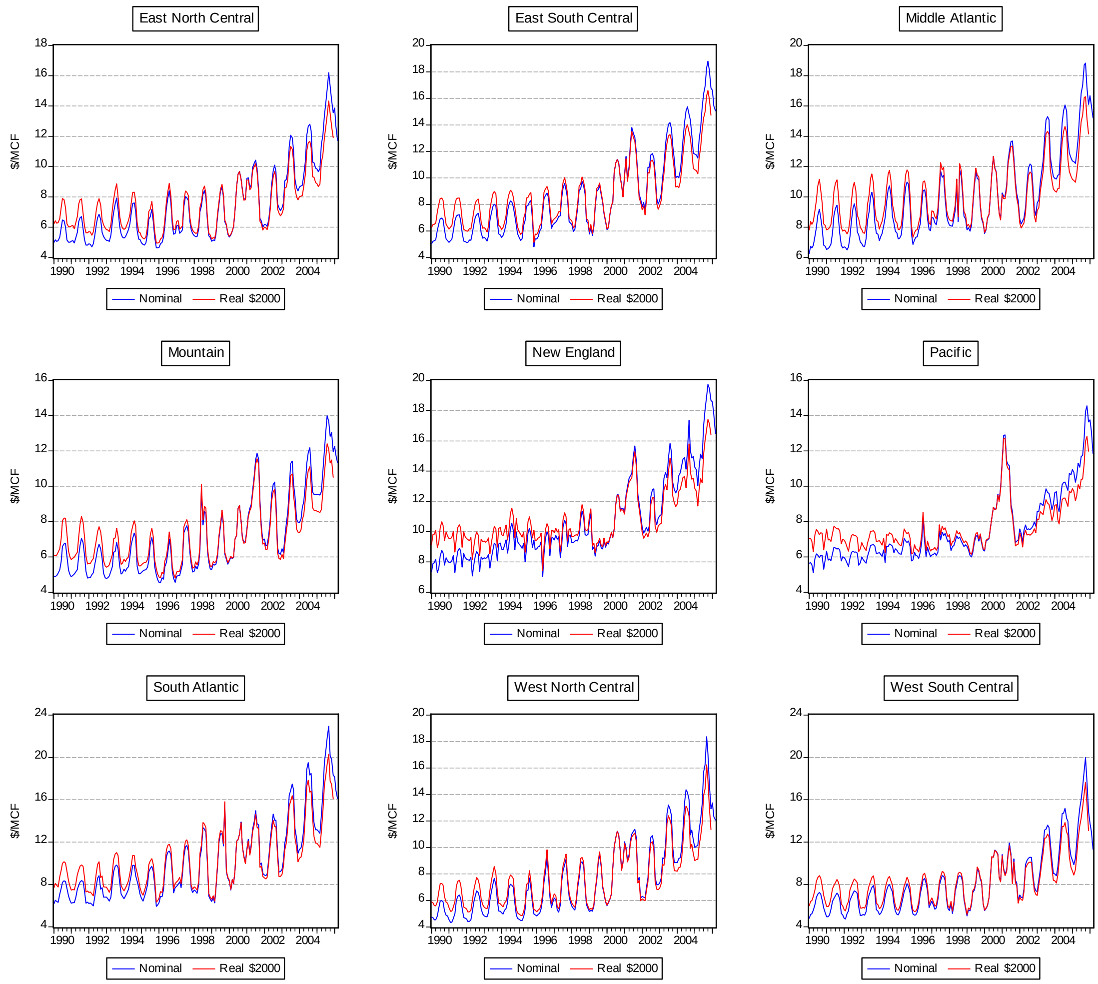
Figure 2
Regional Consumption per Customer per Day
Mcf per Day



Source: U.S. Energy Information Administration

Regional consumption per customer appears to decline for every region for most of the period and particularly after 2000. This has occurred while residential natural gas prices have more than doubled over the same period.

Figure 3
Nominal and Real ($2000) Delivered Natural Gas Prices

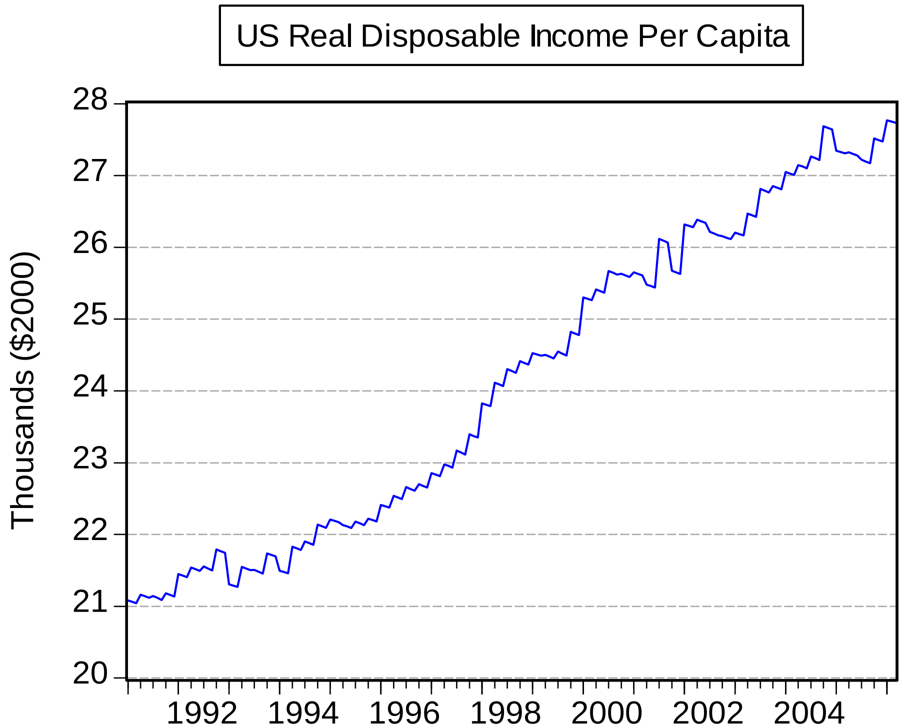


Source: U.S. Energy Information Administration

Residential natural gas prices were fairly stable between 1990 and 1997 during the so-called "gas bubble" period. However, they have been increasing, particularly since 2000 due to a variety of factors, including increasing oil prices (Villar and Joutz, October 2006). Nominal prices have risen faster in some regions than in others; the spread in nominal terms has been between $12/MCF to almost $20/MCF. The real price has more than doubled to over $12/MCF. Natural gas prices have risen about 35 percent to 40 percent faster than the general U.S. price level since 1990. Figure 3 shows the monthly residential natural gas prices per MCF according to the EIA. Figure 4 shows U.S. real disposable income per capita has risen about 33 percent from $21,000 to $28,000 today.

While income is important in any economic analysis of demand, income was not included in our final model for several reasons. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should have been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation. Third, our findings are similar to surveys of natural gas demand by Bohi (1981), Dahl (1993, and personal discussions about preliminary results regarding an update to Dahl's previous study). In a number of papers, Bohi dismisses the large income elasticities from some static cross section estimates and concluded that income is not found to be an important variable in natural gas demand. Dahl found that income effects in residential demand models are consistently small in both aggregate and disaggregate data. Both authors suggest that representing the income effect in residential is problematic and sensitive to the particular study.

Figure 4



Source: Bureau of Economic Analysis, U.S. Department of Commerce

Table 2 shows the cumulative decline of winter weather normal use per customer between 2000 and 2006 for the sample of the LDCs. The focus of Table 2 is the post 2000 period. The intent is to capture the effects of the large increases in natural gas prices and (possible) conservation activities by consumers.[9] The fall, on average, is greater than two per cent per year for six of the nine Census Regions and for the U.S.

[9] The pre-2000 period will be addressed in the statistical modeling sections.

Table 2
Annual Winter Season Weather Normal Natural Gas Use per Residential Customer, By Region and for the U.S.
(Dekatherms per Customer)

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

Table 2 shows the overall decline between 2000 and 2006 for the AGA sample of LDCs. As shown in Table 2, the decline in weather normal use per customer for the national sample is from 64.3 dekatherms in 2000 to 55.9 dekatherms per household in 2006. This represents a cumulative decline of 13.1 percent or an average decline of 2.2 percent per year. The decline since 2004 is even more dramatic, going from 61.9 dekatherms per household in 2004 to 55.9 dekatherms in 2006, nearly a 6 percent decline per year. As shown in this table, every region in the US experienced a decline in use per residential customer.

Section 2: Data

Sixteen AGA member companies provided data for this study. The companies supplied monthly data on residential consumption, average prices, number of customers, heating-degree data, and economic data. Most companies were able to provide a time series of data starting in 1992 and in some cases even into the 1980s. Three companies were unable to contribute data prior to 1999 for accounting or reorganization reasons. The remaining fifteen corporations comprise 46 local distribution companies. This represents more than 16 million customers and 28 percent of all residential customers nationwide.

Micro data on individual consumers is best suited for obtaining estimates of price elasticities. In rate case decisions and in internal LDC corporate strategy decisions however, the most relevant and useful piece of information is how the external forces that bombard it now impact the LDC. These external forces can vary from announcements by Presidents, changes in a competitors pricing, new gas appliance technologies, economic recessions, and gas price increases imposed by fuel surcharges. Since it is the impact of these forces on actual individual LDC's that is relevant, current data on consumption and prices collected by each individual LDC and aggregated at the individual LDC level is best suited to measure the impact of these external forces on a LDC in the current time period.

But data on a single LDC is often not enough information. The problem with using current data from only one LDC is that the number of observations will be quite small, and statistical reliability will be compromised. Instead of tens of thousands of observations on individual consumers, one may be left with 50 or 60 observations for any given LDC during the important winter season months. From a statistical reliability point of view then, it is important to obtain on many different individual LDCs, data that are collected by each individual LDC rather than using survey data collected by government agencies such as the EIA.

In this study, the breadth and depth of the data collected by the AGA has not to our knowledge been done before. The breadth of the data spans the entire US, covering 46 different LDCs. The depth of the data covers almost a decade or more for most of the companies. Therefore, this is a data set that is uniquely suited for the analysis of residential natural gas consumption in the US.

The number of LDCs in each of the nine Census Regions and the percent of total customers the sample covers for each Region is given in Table 3 below.

Table 3
Percent of Total Residential Customers Represented by the AGA Sample

Census Regions	Census Abbreviation	Number of participating LDCs	Coverage
East North Central	ENC	3	8%
East South Central	ESC	3	11%
Mid-Atlantic	MAC	6	45%
Mountain	MTN	5	42%
New England	NEC	8	50%
Pacific	PAC	5	39%
South Atlantic	SAC	5	17%
West North Central	WNC	3	20%
West South Central	WSC	8	32%

Section 3: Approaches to Estimating Short- and Long-run Price Elasticity of Demand

Economists often distinguish between a short-run response and long-run response when referring to how a household changes its natural gas usage when faced with price and income changes. The short-run response is defined as a household's natural gas demand response to natural gas price and income changes given their current capital stock of natural gas-using appliances and shell efficiency of the house. The long-run response is defined as a household's response to natural gas prices changes and income changes after the household has had time to change their stock of gas using appliances and house shell efficiency.

The idea behind the short-run and long-run responses to price changes is that when natural gas prices change, a household's short-run response is to alter the intensity with which they use their current stock of natural gas-using appliances. The long-run response to a change in natural gas prices is to alter the number and efficiency of natural gas using appliances, while at the same time changing the shell efficiency of the house.

A household's percentage change in natural gas demand per one percent change in natural gas price is called the price elasticity of natural gas demand. When this percentage change is computed for a household with a given stock of natural gas-using appliances and house shell efficiency, it is termed the short-run price elasticity of natural gas demand for that household. When this percentage change is computed over a time period long enough to allow a household to change it's stock and efficiencies of house and natural gas using appliances, it is termed the long-run price elasticity of natural gas demand for that household. A similar definition is given to short-run and long-run income elasticities of natural gas demand. If the natural gas demand equation is specified in logarithmic form, the price and income coefficients in a regression equation can be interpreted as the price and income elasticities.

<u>A Dynamic Model of Capital Stock Choice and Natural Gas Demand</u>

For a typical household, natural gas is demanded not for its own sake but for use in furnaces, appliances and the like. The household's accumulated energy saving "capital stock" is determined by income, habits, and past prices of fuels. Consequently, in any period, the household's demand for natural gas is a function of the current price, which influences how intensively the stock of equipment is used, and past prices, which influences the size and composition of that stock. A very simple structural model (Fisher and Kaysen, 1962) of these effects for a given household might be

Demand: $Y_t = \alpha + \beta_1 X_{t-1} + \lambda Z_t + \delta(K_t + E_t) + \varepsilon_t$ (1)

Equipment: $K_t = \gamma_1 X_{t-12} + \gamma_2 Z_t$ (2)

Efficiency: $E_t = \gamma_3 T_t$, (3)

where Y_t is use per household of weather normalized Natural gas at time t, X_{t-1} is the real (base = \$2000) price of natural gas at time t - 1, Z_t is real (base = \$2000) household income at time t, K_t is capital stock with a given efficiency E_t at time t, T_t is a annual time trend to capture technological improvements in the efficiency of the capital stock, and ε_t is a random error term.

We use the real price lagged one period to capture the short-run response to a price change since the current price is not known until the gas bill arrives in the next billing period. Hence, a household's price-induced consumption adjustment during this period is based on last period's real gas price.

If equation (1) is in natural logarithms for Y_t, X_{t-1} and Z_t, the coefficient β_1 can be interpreted at the short-run price elasticity of natural gas demand. It measures the responsiveness of natural gas demand at time t to a change in natural gas price at time t-1 for a fixed capital stock of natural gas appliances K_t. In order to derive the long-run price elasticity of natural gas demand, we need to substitute equations (2) and (3) into equation (1) to get

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_3 Z_t + \beta_4 T_t + \varepsilon_t \qquad (4)$$

If all variables except the time trend are in logarithms, then the coefficient on X_{t-1} is an estimate of the short-run price elasticity, the sum of the coefficients on all price variables is an estimate of the long-run price elasticity, and a negative coefficient (β_4) on the annual time trend is the decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment. Although the length of the lag (t-12) on price in equation (2) to capture the capital stock adjustment process is somewhat arbitrary in this formulation, one can put other restrictions on the shape and length of the price and lagged price coefficients by using models such as the Koyck (1954) or Almon (1965) lag.

The coefficient β_1 in equation (4) gives the short-run price elasticity of natural gas demand. In equation (4) the coefficient β_2 captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. The sum of the coefficients $\beta_1 + \beta_2$ represents the long-run elasticity of natural gas demand. The coefficient β_4 on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by β_2. A negative coefficient (β_4) on the annual time trend is the annual decline in use per household of natural gas demand due to the natural adoption of newer and more efficient capital equipment.

Section 4: Empirical Results Using the AGA Sample of LDCs

The AGA study is interested in answering the following five questions:

(a) What are the changes in natural gas use per residential customer on a weather normalized basis since the year 2000?
(b) What is the short-run price elasticity of demand for residential natural gas customers?
(c) What is the long-run price elasticity of demand for residential natural gas customers?
(d) Has elasticity of natural gas demand changed since 2000?
(e) What is the annual reduction in natural gas usage per customer due to the natural replacement of old inefficient natural gas appliances with more energy efficient appliances; and the building of new homes with greater shell efficiencies compared to existing homes?

To answer these questions we estimated two variants of equations[10] (1) to (3). The first variant assumes the short-run price elasticity has a structural shift in the year 2000 and the second model assumes there is no shift in the short-run price elasticity in the year 2000 and beyond. These two equations are given below as (4a) and (4b), respectively:

$$Y_t = \alpha + \beta_1 X_{t-1} + \delta_{2000} X_{t-1} * D2000 + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \quad (4a)$$

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \quad (4b)$$

where all variables except the time trend are in natural logarithms and D2000 is a 0,1 indicator variable, equal to 0 if the time period is pre year 2000, and equal to 1 if the time period is the year 2000 or greater. The dependent variable Y_t in equations (4a) and (4b) is daily natural gas use per customer in month t.

In equation (4a), the coefficient δ_{2000} is a shift coefficient on the price elasticity given by β_1. The interpretation of δ_{2000} is that β_1 represents the price elasticity of natural gas demand for the period prior to the year 2000, and $\beta_1 + \delta_{2000}$ gives the price elasticity of natural gas demand for the year 2000 and beyond. So a negative δ_{2000} in equation (4a) would indicate that demand

[10] We omitted the income variable Z_t for the reasons outlined the Background Section of the paper. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should has been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation.

has become more elastic since the year 2000. The coefficient β_2 captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. A negative coefficient (β_4) on the annual time trend is the annual decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment.

The sum of the coefficients $\beta_1 + \delta_{2000}$ in equation (4a) gives the short-run price elasticity of natural gas demand in the post-2000 period, the sum of the coefficients $\beta_1 + \delta_{2000} + \beta_2$ represents the long-run elasticity of natural gas demand in the post-2000 period, and the coefficient β_4 on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by β_2.

The interpretation of the coefficients for equation (4b) is similar, except in equation (4b) the slope shift coefficient δ_{2000} for the short-run elasticity is constrained to zero.

Shrinkage Estimators

With a panel data set such at the one used in this study, there is always the question of whether to pool the data and obtain a single estimate of the parameters from the whole sample, or to estimate the equations separately for each cross-section. The implicit assumption in the fixed effects model is that the intercepts are different for each cross-section, but the slope coefficients are the same for all cross sections. This may not be a tenable assumption. Indeed, in practice the constancy of slope coefficients across different cross-section units is often rejected. This implies that the equations should be estimated separately for each cross-section rather than obtaining an overall pooled estimate.

The problem with the two usual estimation methods of either pooling the data or obtaining separate estimates for each cross section is that both are based on extreme assumptions. If the data are pooled as in the fixed effects model, it is assumed the coefficients are all the same. If separate estimates are obtained for each cross section, it is assumed that the coefficients are all different for each cross section. The truth probably lies somewhere in-between. The coefficients are not exactly the same, but there is some similarity between them.

One way to allow for some similarity among the slope coefficients without constraining them to be exactly the same is to assume the coefficients all come from a joint distribution with a common mean and non-zero covariance matrix. This suggests that the resulting coefficient estimates should be a weighted average of the overall pooled estimate and the separate time series estimates based on each cross section. Thus, each cross-section estimate is "shrunk" towards the overall pooled estimate.

For example, consider the model given by equation (4b) and using aggregate data on the nine census Regions to estimate the coefficients. This model is:

$$Y_{it} = \alpha_i + \beta_{i1}X_{i,\,t-1} + \beta_{i2}X_{i,\,t-12} + \beta_{i4}T_{it} + \varepsilon_{it},$$

i = 1,2,3,…..,N (N = 9, Census Regions)

t = 1,2,3,…..T (Time Periods)

The implicit assumption in the fixed effects model is that we retain the i subscript on α but remove the subscript on the β's. The implicit assumption if we run separate regressions for each cross section is that the i subscript is retained on both α and all the β's.

A shrinkage estimator sometimes suggested is the Stein rule estimator defined by:

$$\tilde{\beta}_i = (1 - \frac{c}{F})\hat{\beta}_i + (\frac{c}{F})\hat{\beta}_p \,, \tag{5}$$

where $\tilde{\beta}_i$ is the shrinkage estimator, $\hat{\beta}_i$ is the separate ordinary least square (OLS) estimate from each time series, $\hat{\beta}_p$ is the fixed effects pooled estimator. The F is the F-test statistic used to test the null hypothesis that all the β's are equal across each cross-section. The constant c is given by

$$c = \frac{(N-1)K-2}{NT-NK+2}, \tag{6}$$

and K = 3 and N = 9 in equation 4b.

We will present the shrinkage estimates for the nine Census Regions below when we discuss the regional results.

National Results

We estimated equations (4a) and (4b) for each of the LDCs using OLS on monthly data for the winter season months[11] of October to March. These results are given in the last column of Tables 4 and 5. The average of these individual LDC estimates indicates that the short-run price elasticity of natural gas demand is –0.11, the short-run price elasticity shift in post 2000 is positive but for all practical purposes is zero, the long-run price elasticity given by $\beta_1 + \beta_2$ is –0.20, and the natural annual rate of decline[12] in use per customer due to the adoption of new gas appliance capital equipment is 0.8 percent per year.

[11] Although the dependent variables used to estimate the model are only for the months of October to March, the lagged independent real price variables represent actual lagged calendar month real prices. Hence, for the observation on weather normal use per household in October, the lagged real price (t-1) will be the September real price. Similarly, the lagged real price variable (t-12) for an October observation will be the real price of natural gas in October of the previous calendar year.

[12] If the coefficient on the time trend (T) in equation 4a and 4b is negative, it means there is an annual decline in natural gas weather normal use per customer. The percent decline will be equal to the coefficient on the time trend multiplied by 100%. For example, in Table 4 for the National sample, we see the coefficient on the

We also estimated equations (4a) and (4b) in a pooled regression where each LDC is given company specific intercepts for each of the six winter months in the sample, but all the slope coefficients were assumed to be the same across all LDCs. These estimates are shown in column two of Tables 4 and 5 below. Based on these estimates, we see the short-run price elasticity is –0.09, there is neither a practical nor a statistically significant[13] shift in the elasticity in post 2000, the long-run price elasticity given by $\beta_1 + \beta_2$ is –0.18, and the natural annual rate of decline due to the adoption of new capital equipment is 1.0 percent per year in Table 5. Note the results did not indicate a change in price elasticity in the post-2000 time period in Table 4.

Although we did not obtain Iterative Bayes shrinkage estimates for each individual LDC, based on our experience we expect the average of these shrinkage estimates to fall between the pooled with LDC dummy results and the average of the individual OLS LDC regression results. We conclude therefore, that the short-run price elasticity of natural gas for the national sample lies between –0.09 and –0.10, the long-run price elasticity is between –0.18 and -0.20, and the natural annual rate of decline due to the adoption of new gas appliance capital equipment is between 0.7 percent and 1.0 percent per year. This natural annual rate of decline is consistent with a finding by an earlier AGA report on the decline in weather adjusted gas use per customer. See the AGA report "2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001".

From Table 5 we see the total annual percent decline in use per household one year after a ten percent price increase[14] is between 2.7 percent and 2.8 percent.

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time trend variable is –0.011 for the pooled with LDC dummy variables model. This means there is a 0.011 x 100% = 1.1% annual decline in natural gas weather normal use per customer.

[13] We base this conclusion on the statistical significance of the coefficient on the variable "Ln($Price_{t-1}$)*D2000" in Table 4. See Appendix D for a discussion of the meaning of the term "statistical significance" in statistical hypothesis testing.

[14] Since both the dependent and independent variables are in natural logarithms in equations (4a) and (4b), the coefficients on the two price variables are price elasticities, which give the percent decline in use per customer quantity demanded per one percent increase in price. Similarly, a negative coefficient on the time trend gives the proportionate decline in use per customer per one-year increase in time. To get the percent decline in use per customer one year after a 10 percent increase in price, we have:

percent decline = 10*coefficient on P_{t-1} + 10*coefficient P_{t-12} + 100*coefficient on time trend.

Table 4
National Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln(Price$_{t-1}$)	-0.09 (-6.46)	-0.10
Ln(Price$_{t-1}$)*D2000	0.0036 (0.97)	-0.0003
Ln(Price$_{t-12}$)	-0.09 (-5.93)	-0.09
Annual Time Trend	-0.011 (-9.47)	-0.008
Rbar^2	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.906	
Number of Observations	3023	41

Table 5
National Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln(Price$_{t-1}$)	-0.09 (-6.44)	-0.10
Ln(Price$_{t-12}$)	-0.09 (-5.92)	-0.10
Annual Time Trend	-0.010 (-12.25)	-0.007
Rbar^2	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.908	
Number of Observations	3023	41

Regional Results

Figure 5 shows the normalized consumption of natural gas use per household by U.S. Census region for the AGA sample. There appears to be a decline over much of the sample in all nine Census Regions.

Figure 5
Regional Weather Normal Consumption per Customer
(Dth)

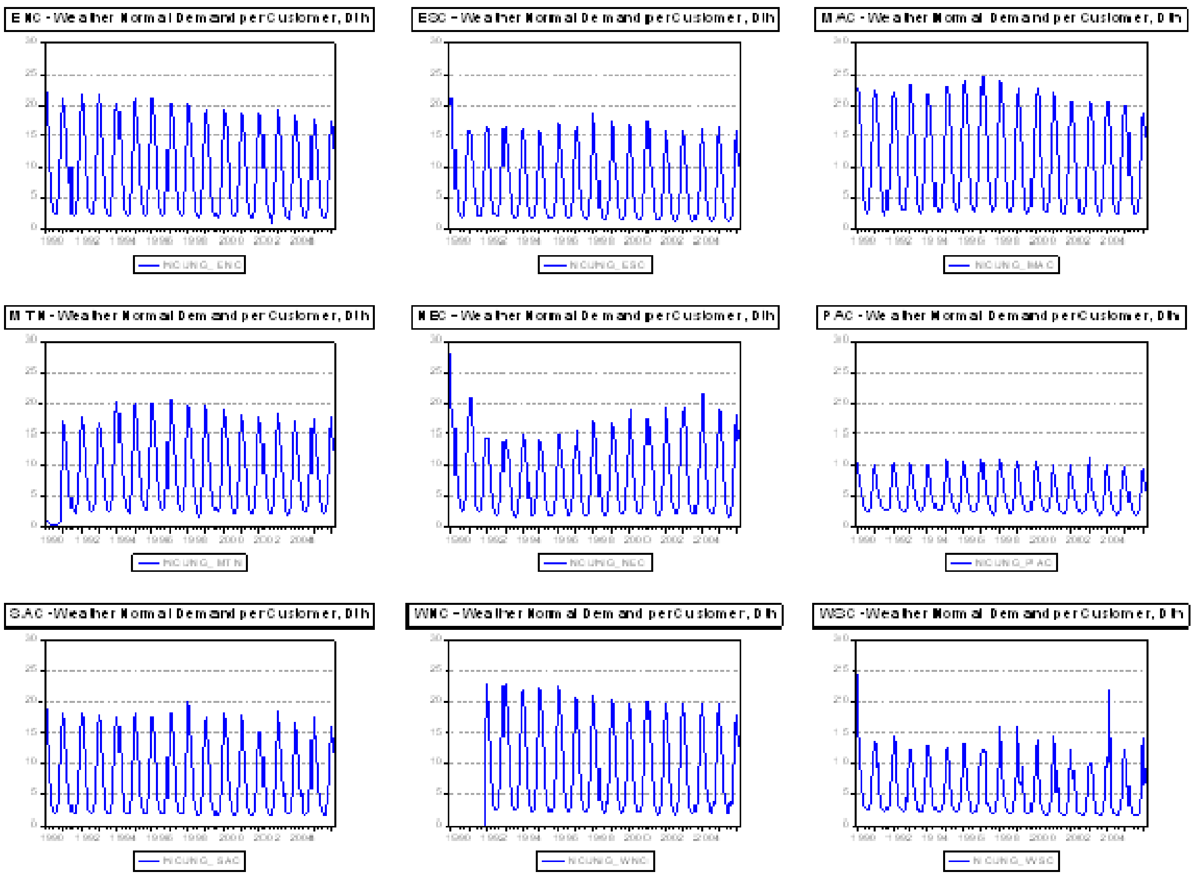
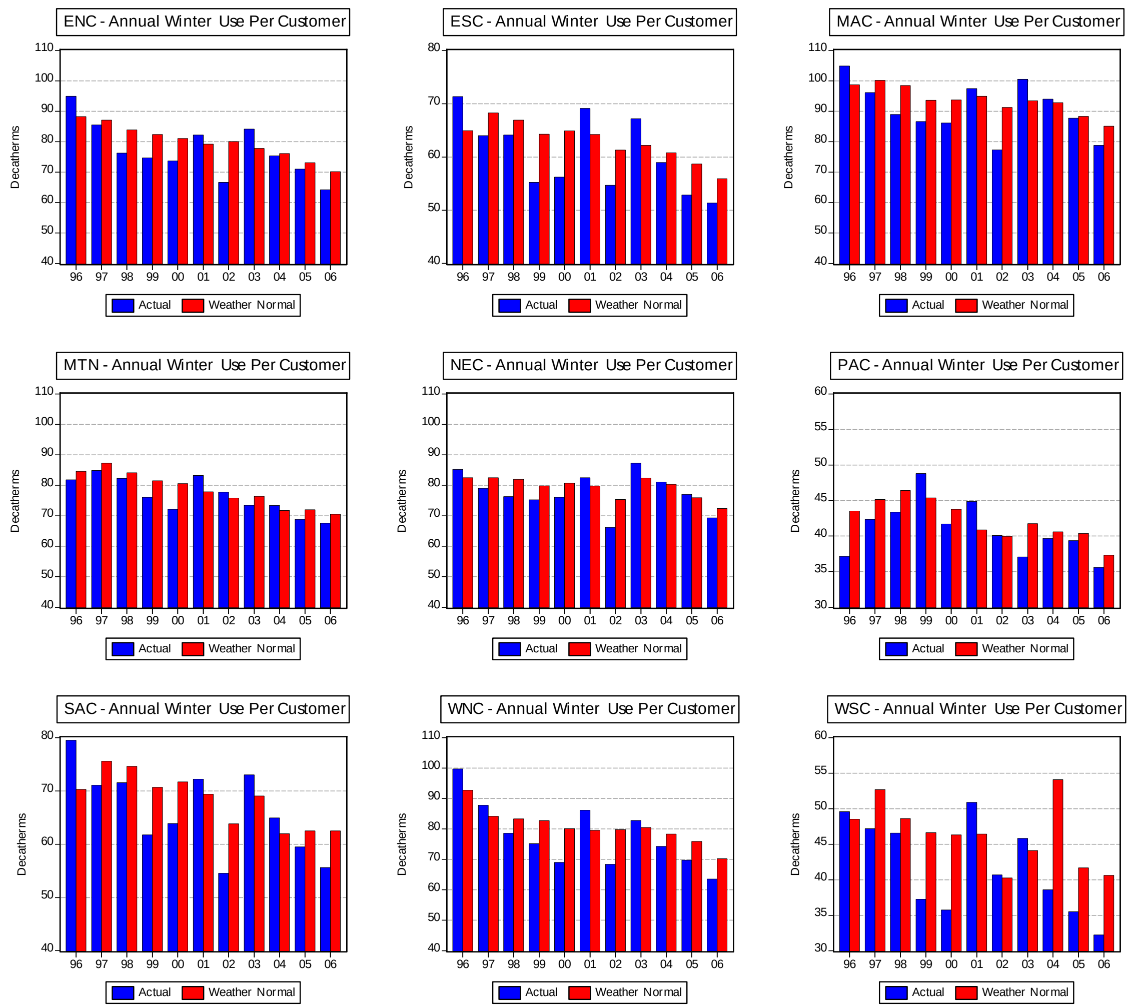


Figure 6 shows the actual and normalized winter season consumption for natural gas per customer by U.S. Census region for the AGA sample. Again, there is a decline over much of the sample in all regions.

Figure 6
Regional Annual Winter Use per Customer
(Dth)



Regional OLS Estimates

Tables 6A and 6B to Tables 14A and 14B give the estimates of equations (4a) and (4b) for each of the nine census Regions using data on the individual LDCs in each of the respective regions. For the most part, the regional results are similar to the national results, with some differences noted below.

East North Central Region

The regression output for the ENC Region is given in Tables 6A and 6B. In Table 6A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 6B, the short-run elasticity is between -0.08 and –0.12, and is statistically significantly different from zero in the pooled model. The long-run elasticity is between –0.22 and –0.27. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 1.0 percent. From Table 6B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.8 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

Table 6A
ENC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-3.02)	-0.12
$Ln(Price_{t-1})$*D2000	0.005 (0.51)	-0.006
$Ln(Price_{t-12})$	-0.14 (-3.63)	-0.16
Annual Time Trend	-0.011 (-3.92)	0.0013
$Rbar^2$	0.99	
Std. Error of Regression	0.064	
Mean of the Dependent Variable	1.319	
AIC	-2.569	
Schwarz Criterion	-2.200	
Number of Observations	195	3

Table 6B
ENC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.08 (-3.02)	-0.12
$Ln(Price_{t-12})$	-0.14 (-3.66)	-0.15
Annual Time Trend	-0.010 (-4.57)	-0.001
$Rbar^2$	0.99	
Std. Error of Regression	0.063	
Mean of the Dependent Variable	1.319	
AIC	-2.578	
Schwarz Criterion	-2.225	
Number of Observations	195	3

East South Central Region

The regression output for the ESC Region is given in Tables 7A and 7B. In Table 7A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 7B, the short-run elasticity is -0.06 when computed from the average of the individual LDC results and for all practical purposes is zero in the pooled regression. The long-run elasticity is between –0.01 and –0.12. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 2.0 percent. From Table 7B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.0 percent and 2.1 percent, which is slightly lower than the annual percent decline in the national sample.

Table 7A
ESC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln(Price$_{t-1}$)	-0.007 (-0.12)	-0.08
Ln(Price$_{t-1}$)*D2000	0.0169 (1.09)	0.02
Ln(Price$_{t-12}$)	-0.03 (-0.47)	-0.06
Annual Time Trend	-0.023 (-4.92)	-0.016
Rbar^2	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.167	
Schwarz Criterion	-0.835	
Number of Observations	227	3

Table 7B
ESC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln(Price$_{t-1}$)	0.012 (0.23)	-0.06
Ln(Price$_{t-12}$)	-0.026 (-0.44)	-0.06
Annual Time Trend	-0.020 (-5.33)	-0.012
Rbar^2	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.170	
Schwarz Criterion	-0.853	
Number of Observations	227	3

Middle Atlantic Region

The regression output for the MAC Region is given in Tables 8A and 8B. In Table 8A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 8B, the short-run elasticity is -0.13 when computed from the average of the individual LDC results, and is –0.10 in the pooled regression. The long-run elasticity is between –0.18 and –0.20. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 1.3 percent. Table 8B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 3.3 percent, which is close to the annual percent decline in the national sample.

Table 8A
MAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.11 (-2.35)	-0.12
$Ln(Price_{t-1})$*D2000	0.01 (1.21)	0.005
$Ln(Price_{t-12})$	-0.09 (-1.70)	-0.04
Annual Time Trend	-0.015 (-5.21)	-0.009
$Rbar^2$	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.681	
Schwarz Criterion	-1.325	
Number of Observations	465	6

Table 8B
MAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.10 (-2.24)	-0.13
$Ln(Price_{t-12})$	-0.10 (-1.77)	-0.05
Annual Time Trend	-0.013 (-5.80)	-0.007
$Rbar^2$	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.682	
Schwarz Criterion	-1.335	
Number of Observations	465	6

Mountain Region

The regression output for the MTN Region is given in Tables 9A and 9B. In Table 9A, we estimate shift of –0.035 in the short-run elasticity in post 2000 and beyond. According to equation (4b) in Table 9B, the short-run elasticity is -0.11 when computed from the average of the individual LDC results and is –0.07 and statistically significant in the pooled regression. The long-run elasticity is between –0.10 and –0.19. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 0.9 percent. In Table 9B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 1.9 percent and 2.8 percent, which in the pooled regression (1.9 percent) is slightly lower than the annual percent decline in the national sample.

Table 9A
MTN Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln($Price_{t-1}$)	-0.014 (-0.52)	-0.08
Ln($Price_{t-1}$)*D2000	-0.035 (-4.19)	-0.02
Ln($Price_{t-12}$)	-0.018 (-0.75)	-0.07
Annual Time Trend	-0.004 (-2.47)	-0.007
$Rbar^2$	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.700	
Schwarz Criterion	-2.353	
Number of Observations	298	4

Table 9B
MTN Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln($Price_{t-1}$)	-0.07 (-2.73)	-0.11
Ln($Price_{t-12}$)	-0.03 (-1.33)	-0.08
Annual Time Trend	-0.009 (-6.22)	-0.009
$Rbar^2$	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.644	
Schwarz Criterion	-2.309	
Number of Observations	298	4

New England Region

The regression output for the NEC Region is given in Tables 10A and 10B. In Table 10A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although in this case it is a shift that lowers the short-run price elasticity and is not practically significant with only 0.015 decrease. According to equation (4b) in Table 10B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is also –0.08 and statistically significant in the pooled regression. The long-run elasticity is between –0.25 and –0.28. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer demand of 0.4 percent. Table 10B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.0 percent, which is close to the annual percent decline in the national sample.

Table 10A
NEC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-3.34)	-0.09
$Ln(Price_{t-1})$*D2000	0.015 (2.44)	0.01
$Ln(Price_{t-12})$	-0.17 (-5.06)	-0.20
Annual Time Trend	-0.008 (-4.24)	-0.005
$Rbar^2$	0.97	
Std. Error of Regression	0.096	
Mean of the Dependent Variable	1.307	
AIC	-1.767	
Schwarz Criterion	-1.413	
Number of Observations	660	8

Table 10B
NEC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.08 (-2.86)	-0.08
$Ln(Price_{t-12})$	-0.17 (-5.00)	-0.20
Annual Time Trend	-0.004 (-3.73)	-0.002
$Rbar^2$	0.97	
Std. Error of Regression	0.097	
Mean of the Dependent Variable	1.307	
AIC	-1.760	
Schwarz Criterion	-1.412	
Number of Observations	660	8

Pacific Region

The regression output for the PAC Region is given in Tables 11A and 11B. In Table 11A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although from a practical point of view this decline is small with an impact of only 0.02. According to equation (4b) in Table 11B, the short-run elasticity is -0.07 when computed from the average of the individual LDC results and is also –0.07 and statistically significant in the pooled regression. The long-run elasticity is between –0.12 and –0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. In Table 11B, we see the total annual percent decline in use per customer one year after a ten percent price increase of 2.0 percent, which is lower than the annual percent decline in the national sample.

Table 11A
PAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.04 (-1.29)	-0.03
$Ln(Price_{t-1})$*D2000	-0.02 (-2.13)	-0.02
$Ln(Price_{t-12})$	-0.05 (-1.66)	-0.07
Annual Time Trend	-0.005 (-1.96)	-0.004
$Rbar^2$	0.98	
Std. Error of Regression	0.072	
Mean of the Dependent Variable	0.910	
AIC	-2.314	
Schwarz Criterion	-1.929	
Number of Observations	258	4

Table 11B
PAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.07 (-2.61)	-0.07
$Ln(Price_{t-12})$	-0.05 (-1.83)	-0.08
Annual Time Trend	-0.008 (-3.87)	-0.005
$Rbar^2$	0.98	
Std. Error of Regression	0.073	
Mean of the Dependent Variable	0.910	
AIC	-2.302	
Schwarz Criterion	-1.931	
Number of Observations	258	4

South Atlantic Region

The regression output for the SAC Region is given in Tables 12A and 12B. In Table 12A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 12B, the short-run elasticity is -0.11 when computed from the average of the individual LDC results and is -0.12 and statistically significant in the pooled regression. The long-run elasticity is between -0.24 and -0.29. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. Table 12B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 3.4 percent to 3.7 percent, which is higher than the annual percent decline in the national sample.

Table 12A
SAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.115 (-3.09)	-0.10
$Ln(Price_{t-1})$*D2000	-0.002 (-0.15)	-0.005
$Ln(Price_{t-12})$	-0.17 (-4.16)	-0.13
Annual Time Trend	-0.008 (-2.58)	-0.009
$Rbar^2$	0.97	
Std. Error of Regression	0.109	
Mean of the Dependent Variable	1.218	
AIC	-1.509	
Schwarz Criterion	-1.146	
Number of Observations	280	4

Table 12B
SAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.12 (-3.30)	-0.11
$Ln(Price_{t-12})$	-0.17 (-4.18)	-0.13
Annual Time Trend	-0.008 (-3.76)	-0.010
$Rbar^2$	0.97	
Std. Error of Regression	0.108	
Mean of the Dependent Variable	1.218	
AIC	-1.516	
Schwarz Criterion	-1.166	
Number of Observations	280	4

West North Central Region

The regression output for the WNC Region is given in Tables 13A and 13B. In Table 13B, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although it is a shift that lowers the short-run price elasticity by only–0.014 and from a practical point of view is not significant. According to equation (4b) in Table 13B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is –0.09 and statistically significant in the pooled regression. The long-run elasticity is between -0.13 and -0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.1 percent. In Table 13B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 2.6 percent, which is close to the annual percent decline in the national sample.

Table 13A
WNC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln(Price$_{t-1}$)	-0.10 (-5.19)	-0.09
Ln(Price$_{t-1}$)*D2000	0.014 (1.98)	0.01
Ln(Price$_{t-12}$)	-0.06 (-2.62)	-0.05
Annual Time Trend	-0.014 (-5.48)	-0.014
Rbar^2	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.141	
Schwarz Criterion	-2.765	
Number of Observations	190	3

Table 13B
WNC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln(Price$_{t-1}$)	-0.09 (-4.78)	-0.08
Ln(Price$_{t-12}$)	-0.06 (-2.69)	-0.05
Annual Time Trend	-0.011 (-5.35)	-0.012
Rbar^2	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.129	
Schwarz Criterion	-2.770	
Number of Observations	190	3

West South Central Region

The regression output for the WSC Region is given in Tables 14A and 14B. In Table 14A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 14B, the short-run elasticity is -0.14 when computed from the average of the individual LDC results and is –0.13 and statistically significant in the pooled regression. The long-run elasticity is -0.16 in both the pooled regression and when computed as the average of the individual LDC OLS estimates. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.6 percent. In Table 14B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

Table 14A
WSC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.12 (-1.71)	-0.13
$Ln(Price_{t-1})$*D2000	-0.008 (-0.48)	-0.009
$Ln(Price_{t-12})$	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.015 (-2.52)	-0.01
$Rbar^2$	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.318	
Schwarz Criterion	0.048	
Number of Observations	450	6

Table 14B
WSC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.13 (-1.87)	-0.14
$Ln(Price_{t-12})$	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.016 (-3.79)	-0.013
$Rbar^2$	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.322	
Schwarz Criterion	0.034	
Number of Observations	450	6

Shrinkage Estimates

We also estimate equation (4a) and (4b) with a type of shrinkage estimator, time series data on the Nine Census Regions, aggregated over the respective LDCs in each region. We will apply the Stein rule estimator discussed above in the sub-section on Shrinkage Estimators. The advantage of shrinkage estimators is that they allow for some similarity among the slope coefficients without constraining them to be exactly the same as in the case of pooled estimates.

Using aggregate regional data, Table 15 below gives the pooled fixed effects estimates of equation (4b) and the average of the individual regional coefficient estimates. These estimates are similar to the estimates presented in Table 5B based on individual LDC data. Note that in Table 5B the impact of a 10 percent price increase was a 2.8 percent decline in use per customer one year later. Using regional aggregate data we see the impact of a ten percent price increase is a similar 2.9 percent decline in use per customer one year later.

Table 15
Regional Elasticity Model Estimates using aggregate data for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With Regional Dummies	Average of Individual Regions
$Ln(Price_{t-1})$	-0.12 (-3.4)	-0.10
$Ln(Price_{t-12})$	-0.06 (-1.63)	-0.08
Annual Time Trend	-0.011 (-3.72)	-0.011
$Rbar^2$	0.98	
Std. Error of Regression	0.094	
Mean of the Dependent Variable	12.14	
AIC	-1.79	
Schwarz Criterion	-1.34	
Number of Observations	540	9

Tables 16 to 24 below present the Stein Shrinkage coefficient estimates of equation (4b) using aggregate regional data. In this case, the shrinkage results are very close to the individual OLS estimates for each Region since F = 0.86 and c = 0.04 since T=60. Plugging into equation (5) we get:

$$\tilde{\beta}_i = 0.95\hat{\beta}_i + 0.05\hat{\beta}_p, \qquad (7)$$

East North Central Region

Table 16 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the ENC Region is -0.047 and -0.122, and the annual time trend shows a declining annual rate of 1.7 percent.

Table 16

ENC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	Estimate	t-stat	
Ln(Price$_{t-1}$)	-0.043	-0.349	-0.047
Ln(Price$_{t-12}$)	-0.076	-0.544	-0.075
Annual Time Trend	-0.017	-1.530	-0.017
Number of Observations	60		

East South Central Region

Table 17 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for East South Central is -0.030 and -0.085, and the annual time trend shows a declining annual rate of 1.8 percent.

Table 17

ESC – Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln(Price$_{t-1}$)	-0.026	-0.180	-0.030
Ln(Price$_{t-12}$)	-0.055	-0.337	-0.055
Annual Time Trend	-0.018	-1.270	-0.018
Number of Observations	60		

Middle Atlantic Region

Table 18 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Middle Atlantic Region is -0.164 and -0.46, and the annual time trend shows a declining annual rate of 0.6 percent.

Table 18

MAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	**OLS on Individual Regional Data**		**Shrinkage Estimator**
	estimate	t-stat	
Ln(Price$_{t-1}$)	-0.167	-1.198	-0.164
Ln(Price$_{t-12}$)	-0.309	-1.887	-0.296
Annual Time Trend	0.006	0.633	0.006
Number of Observations	60		

Mountain Region

Table 19 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Mountain Region is -0.058 and -0.076, and the annual time trend shows a declining annual rate at of 2.22 percent.

Table 19

MTN - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	**OLS on Individual Regional Data**		**Shrinkage Estimator**
	estimate	t-stat	
Ln(Price$_{t-1}$)	-0.055	-0.675	-0.058
Ln(Price$_{t-12}$)	0.022	0.263	0.018
Annual Time Trend	-0.022	-2.767	-0.022
Number of Observations	60		

New England Region

Table 20 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the New England Region is -0.074 and -0.364, and the annual time trend shows a declining annual rate of 0.3 percent.

Table 20

NEC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	**OLS on Individual Regional Data**		**Shrinkage Estimator**
	Estimate	t-stat	
Ln(Price$_{t-1}$)	-0.072	-0.537	-0.074
Ln(Price$_{t-12}$)	-0.302	-1.767	-0.290
Annual Time Trend	-0.003	-0.384	-0.003
Number of Observations	60		

Pacific Region

Table 21 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Pacific Region is -0.089 and -0.179, and the annual time trend shows a declining annual rate of 1.0 percent.

Table 21

PAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	**OLS on Individual Regional Data**		**Shrinkage Estimator**
	estimate	t-stat	
Ln(Price$_{t-1}$)	-0.087	-1.066	-0.089
Ln(Price$_{t-12}$)	-0.092	-1.194	-0.090
Annual Time Trend	-0.010	-1.157	-0.010
Number of Observations	60		

South Atlantic Region

Table 22 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the South Atlantic Region is -0.182 and -0.327, and the annual time trend shows a declining annual rate of 1.9 percent.

Table 22

SAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.185	-1.747	-0.182
Ln($Price_{t-12}$)	0.156	1.371	0.145
Annual Time Trend	-0.019	-1.989	-0.019
Number of Observations	60		

West North Central Region

Table 23 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West North Central Region is -0.088 and -0.120, and the annual time trend shows a declining annual rate of 0.90 percent.

Table 23

WNC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.086	-0.966	-0.088
Ln($Price_{t-12}$)	-0.031	-0.355	-0.032
Annual Time Trend	-0.009	-1.053	-0.009
Number of Observations	60		

West South Central Region

Table 24 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West South Central Region is -0.209 and -0.258, and the annual time trend shows a declining annual rate of 1.1 percent.

Table 24

WSC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	**OLS on Individual Regional Data**		**Shrinkage Estimator**
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.214	-1.719	-0.209
Ln($Price_{t-12}$)	-0.049	-0.368	-0.049
Annual Time Trend	-0.011	-0.946	-0.011
Number of Observations	60		

Our overall assessment of the regional models is that individual coefficients vary[15] greatly across the nine regional models and are often insignificant. This is due to the small sample sizes relative to the national sample, multicollinearity between the two lagged prices, and to some extent multicollinearity with the time trend as well. Yet the average impact of a 10 percent price increase on use per household is remarkably stable and negative across all nine Census Regions in the pooled regressions using individual LDC data. This total decline after a 10 percent price increase for the nine Census Regions is roughly centered on the national impact of a 2.8 percent decline in weather normal use per customer; with the Mountain Region having a 1.9 percent impact at the low end of the range and the South Atlantic Region having a 3.7 percent impact at the high end of the range.

[15] There may be differences in shell efficiency and new home construction and LDC sponsored energy conservations programs across regions that would lead to some heterogeneity in coefficient estimates across the nine census regions. We feel the iterative Bayes shrinkage estimator could remove much of the inconsistency between the national and regional coefficient estimates in a follow up study.

Section 5: Summary of Results and Policy Implications

This research project was initiated to examine the decline in residential natural gas consumption since 2000 and to determine whether there had been a change in the response by residential consumers to higher (and more volatile) natural gas prices. The data that were collected and analyzed support two important findings and a general rule of thumb. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across the LDCs and Census regions.

First, consumption is strongly influenced by seasonal heating needs, response to price change, and the efficiency changes in appliances and home shell efficiency coupled with conservation behavior by consumers. While the separate efficiency and conservation effects due to appliance and housing shell turnover are difficult to disentangle in the current sample, they appear to be discernable from the price effects. Table 25 gives a summary of the national and separate regional price and naturally occurring time trend effects found in this study.

Second, we could not find evidence supporting an appreciable change in the short-run price elasticity of natural gas consumption in the post year 2000 period.

Table 25
Summary of National and Regional
Natural Gas Price Estimates[16]

Region	Short-run elasticity	Long-run elasticity*	Annual Time Trend	Total Response to a 10% Price Increase**
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

* Cumulative: includes impacts of short-run elasticities
** The total response to a 10 percent price increase is the sum of the long-run elasticity and the annual time trend effect.

The results from the price elasticity estimates and the combination of efficiency and conservation estimates are able to explain the post 2000 winter consumption per customer actual experience. Normal winter season natural gas use per household in the US has declined

[16] Estimates obtained from the "fixed effects" pooled regression.

about 13.1 percent between 2000 and 2006. There has been an increase in real natural gas prices of 44 percent for the same time period, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

$$
\begin{array}{ccccc}
\textit{Overall decline} & & \textit{Price Effect} & & \textit{Conservation and} \\
\textit{in Winter Gas Use} & = & \textit{Elasticity with} & + & \textit{Turnover to More} \\
\textit{per Customer} & & \textit{Price Increase} & & \textit{Efficient Appliances} \\
13.9\% & = & 0.18\, x\, 44\% & + & 6\, x\, 1.0\% \\
 & = & 7.9\% & + & 6.0\%
\end{array}
$$

In the expression above, the left hand term is the overall declining rate of winter gas use per customer, the first term on the right hand side is the price effect reflecting elasticity with price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

This proposed rule of thumb suggests that twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by buying more efficient appliances, and a 1 percent drop in gas usage per customer due to the natural turnover to more efficient gas appliances each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

It should be noted that the 1 percent price-induced drop with the current capital stock is what economist refer to as the elasticity of “short-run” demand. This refers to customers “turning down the thermostat”. There is a second 1 percent price induce drop in use per customer that occurs one year later due to consumers buying more efficient appliances and increasing the tightness of the home. The price elasticity in the “long-run” is the sum of the short-run demand elasticity and the additional changes that occur to quantity demanded one year later because of natural gas price impacts on consumer choice of appliance and home thermal shell efficiency.

The heightened conservation behavior by consumers is partly due to the many government and utility programs that currently exist to encourage residential consumers to save energy:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for purchase of efficient appliances and shell improvements, and consumer education on the importance of saving energy.

- State and local governments also encourage efficiency through similar programs
- Many utilities provide rebates, incentives, and assistance to their customers to improve use of energy. For example, electric and natural gas utilities provided more than $140 million in 2005 to assist low-income customers to weatherize their homes {Source: http://liheap.ncat.org/tables/FY2005/05stlvtb.htm }

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following year. This is driven by the historical forces related to the natural turnover of old appliances to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in shell efficiency from new construction will result in continued conservation, regardless of price changes, impacting utility operations. Third, even if future gas prices remain constant or even decrease, the appliance and home shell efficiency gains achieved in prior years will not be reversed.

Suggestions for Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from Natural Gas Companies that did not participate in the initial study.

- Try different specifications of the model.

- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.

- Consider the impact of competition from the electric utility industry.

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Appendix A: Construction of Weather-Normalized Series for Use per Customer

Step 1. Calculate the ratio of HDDN to HDD (normal heating degree days / actual heating degree days.) this is referred to as the weather normalization factor

Step 2. Construct a proxy for base natural gas consumption per customer for each "year". Calculate the average of July and August for each year.

Step 3. Subtract the base consumption from Actual consumption for the September through June for the next 10 months. Refer to this as "heating" consumption. Example: the average of July and August 1999 will be subtracted from September 1999 through June 2000. Retain the actual values for July and August 1999 in the "heating" consumption variable.

Step 4. Calculate the weather normal consumption per customer series. Multiply the "heating" consumption variable by the weather normalization factor. Intuitively, a very cold winter will have relatively high levels of consumption. The very cold weather means that the denominator in the weather normalization factor is large relative to the normal HDD. Multiplying the large consumption variable times the factor, which is less than one, will bring back or reduce consumption towards the normal "heating" consumption level.

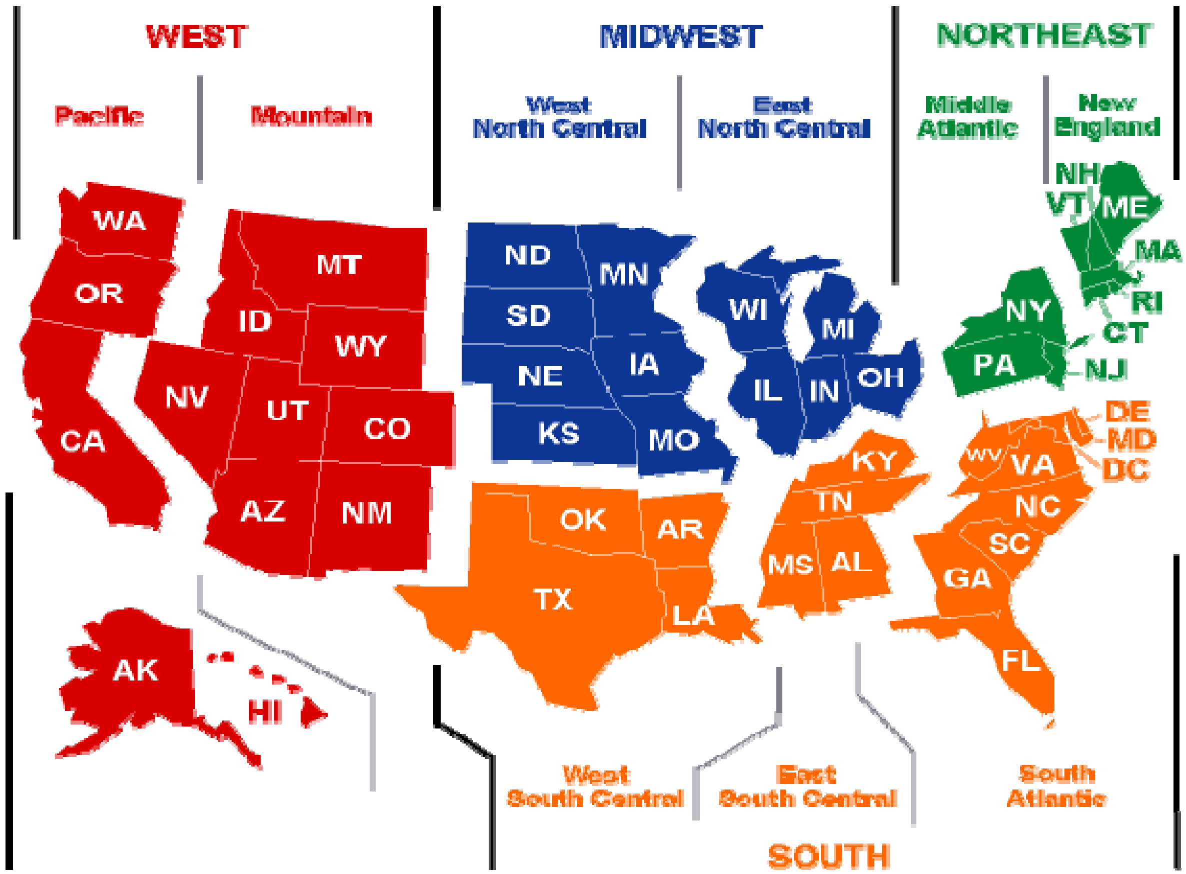
Step 5. Add the base consumption per customer back into the September through June normal heating consumption levels.

Variable list omitting the region identifiers:

HDD	– Actual Heating Degree Days
HDDN	- Normal Heating Degree Days
CUNG	- Natural Gas Use per Customer per Month
ZSAJQUS	- Days per Month
WNF	- Weather Normalization Factor
	WNF = HDDN / HDD
Base	- Average of July and August in a year
HCUNG	- "Heating" Natural Gas Use per Customer per Month
	HCUNG = CUNG – Base
NCUNG	- "Normalized" Natural Gas Use per Customer per Month
	NCUNG = (HCUNG * WNF) + Base
CUNGW	- Actual Daily Natural Gas Use per Customer per Month
	CUNGW = CUNG / ZSAJQUS
NCUNGW	- "Normalized" Natural Gas Use per Customer per Month
	NCUNGW = NCUNG / ZSAJQUS

Appendix B: U.S. Census Regions

Figure B.1
U.S. Census Region Map



Source: U.S. Dept. of Energy **http://www.eia.doe.gov/emeu/cbecs/census_maps.html**

Table B.1
U.S. Census Region Definitions

Division 1 New England	Division 3 East North Central	Division 5 South Atlantic	Division 7 West South Central	Division 9 Pacific
Connecticut	Illinois	Delaware	Arkansas	Alaska
Maine	Indiana	District of Columbia	Louisiana	California
Massachusetts	Michigan	Florida	Oklahoma	Hawaii
New Hampshire	Ohio	Georgia	Texas	Oregon
Rhode Island	Wisconsin	Maryland		Washington
Vermont		North Carolina	**Division 8 Mountain**	
	Division 4 West North Central	South Carolina		
Division 2 Middle Atlantic		Virginia	Arizona	
	Iowa	West Virginia	Colorado	
New Jersey	Kansas		Idaho	
New York	Minnesota	**Division 6 East South Central**	Montana	
Pennsylvania	Missouri		Nevada	
	Nebraska	Alabama	New Mexico	
	North Dakota	Kentucky	Utah	
	South Dakota	Mississippi	Wyoming	
		Tennessee		

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

U.S. Census Region Pneumonic	
ENC	East North Central
ESC	East South Central
MAC	Middle Atlantic
MTN	Mountain
NEC	New England
PAC	Pacific
SAC	South Atlantic
WNC	West North Central
WSC	West South Central

Appendix C: Literature Review[17]

There are many studies on the price and income elasticities of residential energy goods in general, and of residential natural gas demand in particular. Table 1 below lists some of these studies, along with the short-run and long-run estimates. See Dahl and Roman (2004) and Dahl (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). Common drawbacks of these studies are: (1) they do not include data that contain the recent increases in residential natural gas prices, (2) they do not focus on the winter season demand, (3) they do not contain company level data across the entire US, and (4) most do not allow for a non-price related decline in use per customer that occurs automatically as consumers replace old inefficient appliances with newer more efficient ones.

The AGA study overcomes the missing elements in the existing literature by looking at individual company level winter season monthly data from all nine US Census Regions over the period 1981 to 2006. Also, the AGA study allows for a naturally occurring decline in use per customer that results from the replacement of old inefficient gas appliances with newer more efficient models.

There have been many papers written that estimate the price elasticity of residential demand for natural gas. A partial list of these papers is given in the references section. Estimates of short-run price elasticity range from as low as –0.05 in Beirlein, Dunn and McConnon (1981) to as high as –0.68 in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates the range of estimates is even higher, with the low being -0.017 in Hewlett (1977) to as high as –3.42 in Beirlein, Dunn and McConnon (1981).

It is fair to say there is no real consensus on residential natural gas price elasticity demand estimates. For overall residential energy demand in general, the median estimate of short-run price elasticity is about –0.2, with the long-run dynamic models with lagged dependent variables yielding a median estimate of about –0.48. For natural gas in particular, using EIA state level aggregate data, Maddala, et. al. (1997) estimate the average short-run price elasticity of natural gas is –0.1 and the long-run price elasticity of residential natural gas demand is –0.27.

[17] This appendix benefited from discussions and on-going research by Professor Carol Dahl, the Colorado School of Mines, Golden, Colorado. All errors are ours.

Table C.1
Residential Price Elasticity Estimates

Authors	Data	Estimation Method	Short-run	Long-run
Balestra & Nerlove (1966)	Pooled: 36 States for 1957-62)	GLS(EC)	NA	-0.63
Jaskow & Baughman (1976)	Pooled: 48 States for 1968-72	OLS	-0.15	-1.01
Berndt & Watkins (1977)	Pooled: Ontario and British Columbia for 1959-74	Maximum Likelihood	-0.15	-0.69
Hewlett (1977)	Cross Section: New York State household survey	OLS	NA	-0.45
Hewlett (1977)	Pooled: New York State customer survey for 1976 and 1977.	OLS	NA	-0.17
Beirlein, Dunn & McConnon (1981)	Pooled: 9 States for 1967-77	OLS	-0.23	-2.90
		GLS (EC)	-0.23	-2.96
		GLS (EC-SUR)	-0.05	-3.42
Barnes, Gillingham & Hagemann (1982)	Pooled: 10,000 households in 23 US cities. Quarterly data for 1972-73.	IV	-0.68	NA
Green & Gilbert (1983)	Cross-Sectional: non-poverty homeowners and poverty homeowners	OLS	NA	-1.25
		OLS	NA	-1.09
Blattenberger, Taylor, & Rennhack (1983)	Pooled: 48 states for 1961-74	GLS (EC)	-0.32	-0.39
Green, Salley, Grass & Osei (1986)	Pooled: between 6 and 7 thousand households for 1974 to 1979.	OLS	-0.16	NA

Appendix D: Statistical Hypothesis Testing

The practical question that is addressed in statistical hypothesis testing concerns the relative strength of some “treatment”; such as does price have an impact on weather normal use per household natural gas demand. The question addressed might be: Do the data contained in the sample present sufficient evidence that increases in price lead to a lower use per household natural gas demand?

The reasoning employed in testing a hypothesis bears a striking resemblance to the procedure used in a court trial. In tying a person for a crime, the court assumes the accused innocent until proven guilty. The prosecution collects and presents all the available evidence in an attempt to contradict the “not guilty” hypothesis and hence to obtain a conviction. However, if the prosecution fails to disprove the “not guilty” hypothesis, this does not prove that the accused is “innocent” but merely that there is not sufficient evidence to conclude that the accused is “guilty”.

The statistical problem in this study portrays “natural gas price” as the accused. The hypothesis to be tested, called the **null hypothesis**, is that price does not negatively impact the weather normal use per household natural gas demand. The evidence in this case is contained in the sample drawn from the population of LDCs who supply this demand. The researcher, playing the role of the prosecutor, believes that an **alternative hypothesis** is true - namely, that natural gas price does have a negative impact on natural gas use per household demand. Hence, the researcher attempts to use the evidence contained in the sample to reject the null hypothesis (no impact of natural gas price on natural gas demand) and thereby to support the alternative hypothesis, the contention that price does in fact inversely impact natural gas demand.

The statistician will calculate a test statistic from the information contained in the sample. All possible values the test statistic may assume are divided into two groups – one called the rejection region and the other the acceptance region. After the sample is collected the test statistic is calculated and observed. If the test statistic takes on a value in the rejection region, the null hypothesis is rejected. Otherwise, one fails to reject the null hypothesis.

You will notice that the researcher is faced with two possible types of errors. On the one hand, the researcher might reject the null hypothesis when it is true, and falsely conclude that natural gas price does negatively impact the natural gas demand. This would result in forecasting lower revenues after a rate increase than would actually be the case. On the other hand, the researcher might decide not to reject the null hypothesis when it is false, and falsely conclude that natural gas price does not impact natural gas demand. This error would result in forecasting higher revenues after a rate increase than would actually be the case.

Rejecting the null hypothesis when it is true is called a Type I error for a statistical test. The probability of making a type I error is usually denoted by the Greek symbol α, and is referred to as the “statistical significance level”. In practice some common values used for

α are 0.10 (a 10 percent chance of a Type I error), 0.05 (a 5 percent chance of a Type I error), 0.025 (a 2.5 percent chance of a Type I error), and 0.01 (a 1 percent chance of a Type I error).

The probability α will increase or decrease as we increase or decrease the size of the rejection region. Then why not decrease the size of the rejection region and make α as small as possible? Unfortunately, decreasing α increases the probability of not rejecting the null hypothesis when it is false and some alternative hypothesis is true. This second type of error is called the type II error for a statistical test and its probably is commonly denoted by the Greek symbol β. More formally, accepting the null hypothesis when it is false is called a type II error for a statistical test. The probability of making a type II error when some specific alternative is true is denoted by β.

Notice that both errors cannot be committed simultaneously. A type I error is possible only if the decision is to reject the null hypothesis; a type II error is possible only if the decision in to not reject the null hypothesis.

When the null hypothesis is rejected in favor of the alternative hypothesis, it is called a statistically significant test. When one fails to reject the null hypothesis, it is referred to as a statistically insignificant test.

As noted on page 29 of Maddala (2001), a statistically significant test means, “sampling variation is an unlikely explanation of the discrepancy between the null hypothesis and the sample values (estimate)”. On the other hand, a statistically insignificant test means, “sampling variation is a likely explanation of the discrepancy between the null hypothesis and the sample value”.

The appropriate test statistic for the null hypotheses tested in this report is the t-statistic, which is reported for each of the coefficients in equations (4a) and (4b). For sample sizes larger than 120 and for an alternative hypothesis that states the price coefficient is less than zero, a t-statistic less than -1.28 is statically significant at the 10 percent level, a t-statistic less than -1.64 is statistically significant at the 5 percent level, a t-statistic less than -1.96 is statically significant at the 2.5 percent level, and a t-statistic less than -2.33 is statistically significant at the 1 percent level.

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