COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

RECEIVED
AUG 01 2013
PUBLIC SERVICE COMMISSION

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

1. Please refer to page 3, lines 18 through 19, of Mr. Kollen's testimony.

(a) Please provide all work papers, spreadsheets, and calculations electronically, with formulas intact and visible, and no pasted values, used by Mr. Kollen in calculating the amount the Company requests to recover through a proposed rider relating to the REPA.

(b) Please identify separately each assumption relied upon by Mr. Kollen in connection with his calculations and all authority relied upon by Mr. Kollen in electing to use any such assumptions.

(c) Please identify the value(s) Mr. Kollen assumed or used, if any, for Section 45 production tax credits in calculating the amount referenced in part (a) above.

(d) If Mr. Kollen assumed a value for Section 45 production tax credits in calculating the amount referenced in part (a) above, please identify the amount and all authority relied upon by Mr. Kollen in selecting the value(s) assumed or used.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

(e) If Mr. Kollen did not assume a value for Section 45 production tax credits in calculating the amount referenced in part (a) above, please explain why no value was assumed or used and all authority relied upon by Mr. Kollen in failing to use or assume a value.

(f) Please identify and provide all additional support relied on by Mr. Kollen in calculating the amount referenced in part (a) above.

RESPONSE:

(a) See attached CONFIDENTIAL electronic file entitled "Attachment 1 – Estimated REPA Payments" – FILED UNDER SEAL.

(b) Mr. Kollen used the purchased power expense shown on Mr. Wohnhas' Exhibit RKW-1 of $50.661 million for Year 1. Mr. Kollen then escalated the Year 1 amounts by [redacted]% each year through the twenty-year term of the contract based on the Option 1 annual fixed price escalation factor. He then summed the annual amounts.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

(c) Mr. Kollen's calculations were based on the estimated Year 1 cost of service provided by Mr. Wohnhas on Exhibit RKW-1, which did not include the Section 45 PTCs. On page 4, lines 6-8 of his Direct Testimony, Mr Wohnhas states that "this estimated cost of service does not account for any potential offset related to the Section 45 Production Tax Credits." If the Section 45 Production Tax Credits are available, then there should be a reduction in the contract prices; however, the REPA does not specify the amount by which the contract prices will be reduced.

(d) See response to subpart (c).

(e) See response to subpart (c).

(f) See response to subpart (b).

SPONSORING WITNESS: Lane Kollen

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

2. Please refer to page 5, lines 7 through 9, of Mr. Kollen's testimony. Please identify by location in the record of this proceeding all record evidence upon which Mr. Kollen relies in stating that the "Company readily acknowledges" that the capacity and energy from the REPA is not least cost. If Mr. Kollen relies upon any matter outside the record of this proceeding please identify the matter and provide a copy.

RESPONSE:

Please refer to Mr. Pauley's Direct Testimony at 6 in this proceeding wherein he is asked if the REPA is the least cost alternative and answers "no" as follows:

> ***Q. IS THE ECOPOWER REPA THE LEAST COST ALTERNATIVE TO SUPPLY THIS CAPACITY AND ENERGY?***
>
> *A. No.*

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

Please also refer to Mr. Pauley's Direct Testimony at 8 in this proceeding wherein he is asked if the Commission should approve the REPA even if it is not the least cost alternative and answers "yes." Mr. Pauley states further in his answer: "While the renewable energy generated from the ecoPower project is more costly than traditional forms of non-renewable electric generation . . . "

In addition, in response to AG 1-7, which asserted that "KPCO has conceded that the proposed Purchase Agreement is not the least cost alternative to supply capacity and energy," the Company admitted that the REPA was not the least cost option, stating: "It is unlikely that any renewable resources in Kentucky would be the least cost option. However, to move forward with fuel diversity, the Commission must decide when and if it is the proper time to approve a facility that is not the least cost option."

SPONSORING WITNESS: Lane Kollen

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

3. Please refer to page 6, lines 1 through 3, of Mr. Kollen's testimony.

(a) Please provide all work papers, spreadsheets, and calculations electronically, with formulas intact and visible, and no pasted values, used by Mr. Kollen in calculating an initial rate increase of $39.284 million.

(b) Please identify separately each assumption relied upon by Mr. Kollen in connection with his calculations referenced in part (a) above and all authority relied upon by Mr. Kollen in electing to use any such assumptions.

(c) Please identify and provide all additional support relied on by Mr. Kollen in calculating the amount described in part (a) above.

RESPONSE:

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

(a) Mr. Kollen provided a detailed description of all calculations and sources of information in his Direct Testimony at 15 - 16. Mr. Kollen did not create an electronic spreadsheet to make the calculations.

(b) See response to subpart (a).

(c) See response to subpart (a).

SPONSORING WITNESS: Lane Kollen

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

4. Please refer to page 6, lines 6 through 7, of Mr. Kollen's testimony.

(a) Please provide all work papers, spreadsheets, and calculations electronically, with formulas intact and visible, and no pasted values, used by Mr. Kollen in his calculation of "yet another 5.3% to the total rate increases over the term of the REPA."

(b) Please identify separately each assumption relied upon by Mr. Kollen in connection with his calculations referenced in part (a) above and all authority relied upon by Mr. Kollen in electing to use any such assumptions.

(c) Please identify and provide all additional support relied on by Mr. Kollen in making the calculations referenced in part (a) above.

RESPONSE:

(a) See electronic file attached entitled "Attachment 1 – Estimated REPA Payments" provided in response to Item 1 of this Set of Requests.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

(b) See response to subpart (a). Mr. Kollen calculated the estimated increase in the annual expense pursuant to the REPA in Year 20 compared to Year 1 and then divided this increase by the Company's total revenues in Year 1 shown on Exhibit Exhibit RKW-1.

(c) See response to subpart (a).

SPONSORING WITNESS: Lane Kollen

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS

5. Please refer to page 9, line 1, of Mr. Kollen's testimony. Please identify by location in the record of this proceeding all record evidence upon which Mr. Kollen relies in stating the "Company readily admits that the REPA is not needed." If Mr. Kollen relies upon any matter outside the record of this proceeding please identify the matter and provide a copy.

RESPONSE:

Please refer to the Company's response to Staff 2-1(b) wherein it stated: "Assuming the Mitchell transfer is approved, and further assuming Big Sandy Unit 1 were to be retired and replaced with an alternative, more cost-effective source of roughly equivalent capacity (and energy), the REPA capacity and energy would not be required."

In addition, please see the Company's responses to KIUC 1-1 and 1-19. The Company did not issue an RFP for power. Instead, ecoPower made an unsolicited proposal to the Company.

Further, the Company acknowledges that it has not performed any analysis or studies documenting a need for the REPA.

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

Finally, neither the Company in its Application nor any of the Company's witnesses affirmatively asserts that the REPA is necessary to meet the Company's capacity or energy requirements.

SPONSORING WITNESS: Lane Kollen.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

6. Please refer to page 16, line 8 through page 17, line 1, of Mr. Kollen's testimony.

(a) Please identify the elements of the strict scrutiny test advocated by Mr. Kollen.

(i) Please provide a citation to, and copy of, each Kentucky Public Service Commission decision applying the strict scrutiny test advocated by Mr. Kollen whether in the context of a biomass REPA or otherwise.

(ii) Please identify and provide the relevant statutory, case law, and Commission decisional basis supporting Mr. Kollen's contention that the Commission is to apply the "strict scrutiny" standard advocated by Mr. Kollen.

(b) Please identify and provide all support for Mr. Kollen's assertion that the Kentucky Legislature, through enacting SB 46, has given the developers of biomass power plants an undue advantage.

(c) Does Mr. Kollen contend that the claimed "undue advantage" for biomass power plants is illegal, unconstitutional or results in rates that are not fair, just and reasonable?

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

If so, please identify and provide all authority relied upon by Mr. Kollen in so contending.

RESPONSE:

(a) First, the capacity and energy should be needed as a condition to approval of any resource, including renewable resources. Second, the capacity and energy should be the least cost resource, if, in fact, capacity and energy are needed, regardless of whether the resource is renewable or not. Third, the contract should be void or voidable if it was procured by fraud, consistent with normal contract law. Fourth, the price should be defined; more specifically, the value of the Section 45 PTCs as a reduction to the contract prices should be set forth upfront rather than subject to future negotiation.

(b) The legislature has not adopted legislation that provides similar favorable treatment for other resources.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

(c) It will result in rates that are not fair, just and reasonable if the resource is not needed or is not the least cost if it is needed and could result in rates that are not fair, just and reasonable if the contract was procured by fraud.

SPONSORING WITNESS: Lane Kollen

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

7. Please refer to page 4, lines 5 through 14, of Dr. Coomes' testimony.

(a) Please confirm there would be a positive net regional economic impact from the Facility if it were to be compared to the regional economic implications of purchasing an equivalent amount of capacity and energy from the PJM spot-market.

(b) If the answer to this data request is anything but an unqualified "yes," please provide each fact relied upon by KIUC in failing to answer with an unqualified "yes."

(c) If the answer to this data request is anything but an unqualified "yes," please provide each document relied upon by KIUC in failing to answer with an unqualified "yes."

SPONSORING WITNESS: Paul Coomes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

RESPONSE:

I understand the question to be a hypothetical one, to make a regional economic comparison between a biomass generation plant that uses wood from the region and a coal-fired generation plant that uses coal from outside the region. Under that scenario, I agree that, considering only the fuel aspect, there would be a positive net regional economic impact from the biomass plant. However, given the huge coal reserves and production in the 20-county region, that scenario did not seem reasonable for me to use as a comparison. Additionally, there is no guarantee that all the wood flowing to the proposed biomass facility would come from the 20-county region. Since there is an abundance of both coal and wood in the region, it seemed appropriate to me to compare the generation impacts under the assumption that the fuel would be obtained from the region. Moreover, I estimate that the negative economic impacts in the region due to higher electricity rates associated with the biomass facility would roughly offset any economic gains in the region due to wood purchases.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

8. Please refer to page 2 of the Exhibit to the testimony of Dr. Coomes labeled "Net economic impacts of the proposed ecoPower plant."

(a) Please identify each "existing coal-fired power plant" or "coal-fired alternative" Dr. Coomes utilizes for comparison in his study. For each "existing coal-fired power plant" or "coal-fired alternative" utilized by Dr. Coomes please identify the following:

(i) The plant or unit names;

(ii) The owner;

(iii) The plant or unit location;

(iv) The RTO in which the plant or unit is located;

(v) The amount of available capacity and energy from that plant or unit;

(vi)The percentage of coal used by that plant or unit that is mined in the economic region modeled by Dr. Coomes; and

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

(vii) The ability of the plant or unit to comply with all known environmental regulations, including without limitation the mercury and air toxics standard ("MATS")

(b) If the units or plants are located outside PJM, please identify whether those plants or units have firm long-term transmission rights into PJM.

(c) Please identify the Kentucky counties that comprise the "region" used by Dr. Coomes in his study.

RESPONSE:

On page 2, I outline the general method, but later starting on page 4 I provide much of the specific documentation requested. As stated in footnotes 2 and 5, the Big Sandy plant is used as my coal-fired generation comparison. I do not know how much of the coal used there is mined in the 20-county economic region. Also, I do not know about PJM transmission rights or compliance with environmental regulations.

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

(c) The twenty counties comprising the region are the ones shown in KPSC documents as the Kentucky Power service territory: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike and Rowan. I apologize for the oversight, as I thought I had documented the geography in my report.

SPONSORING WITNESS: Paul Coomes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS

9. Please provide in machine readable, executable format all input and output files used or produced by Dr. Coomes as part of the IMPLAN modeling relied upon by Dr. Coomes in his testimony or the exhibits thereto.

RESPONSE:

I am in Colorado on vacation and the IMPLAN files are on my office computer. With your permission I will submit them by August 5. The actual IMPLAN files are only readable by a licensed user, however, and may not be useful to you. Alternatively, here are the inputs and outputs from my IMPLAN session, in text form.

SPONSORING WITNESS: Paul Coomes.

IMPLAN INPUT FOR SIMULATIONS

Wood as Fuel

	IMPLAN Sector	Demand
16	Commercial logging	$6,531,737
95	Sawmills	$4,354,492
335	Trucking	$3,519,841
	Total regional demand	$14,406,071

Coal as Fuel

	IMPLAN Sector	Demand
20 21	Coal mining	$10,705,486
334	Water transportation	$2,174,069
	Total regional demand	$12,879,555

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

IMPLAN SUMMARY OUTPUT:

Wood as Fuel, Transportation to Generating Facility by Truck

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	104.9	$3,767,643	$1,588,804	$14,406,070
Indirect Effect	45	$1,686,445	$2,298,431	$6,004,368
Induced Effect	26.4	$941,395	$1,800,649	$3,145,444
Total Effect	176.4	$6,395,483	$5,687,884	$23,555,883

Coal as Fuel, Transportation to Generating Facility by Barge

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	34.4	$3,134,005	$6,379,004	$12,879,555
Indirect Effect	18.2	$869,653	$1,525,899	$3,743,842
Induced Effect	19.9	$709,696	$1,351,487	$2,367,922
Total Effect	72.6	$4,713,354	$9,256,390	$18,991,319

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS

10. Please refer to page 11 of the Exhibit to the testimony of Dr. Coomes labeled "Net economic impacts of the proposed ecoPower plant." Please provide a copy of the "Regional Differences in the Price-Elasticity of Demand for Energy," by Mark Bernstein and James Griffin, RAND Technical Report, dated 2005.

RESPONSE:

See attached.

SPONSORING WITNESS: Paul Coomes.

This product is part of the RAND Corporation technical report series. Reports may include research findings on a specific topic that is limited in scope; present discussions of the methodology employed in research; provide literature reviews, survey instruments, modeling exercises, guidelines for practitioners and research professionals, and supporting documentation; or deliver preliminary findings. All RAND reports undergo rigorous peer review to ensure that they meet high standards for research quality and objectivity.

TECHNICAL
REPORT

Regional Differences in the Price-Elasticity of Demand For Energy

Mark A. Bernstein, James Griffin

Prepared for the National Renewable Energy Laboratory

RAND INFRASTRUCTURE, SAFETY, AND ENVIRONMENT

The research described in this report was conducted under the auspices of the Environment, Energy, and Economic Development Program (EEED) within RAND Infrastructure, Safety, and Environment (ISE), a division of the RAND Corporation, for the National Renewable Energy Laboratory.

Published 2005 by the RAND Corporation
1776 Main Street, P.O. Box 2138, Santa Monica, CA 90407-2138
1200 South Hayes Street, Arlington, VA 22202-5050
201 North Craig Street, Suite 202, Pittsburgh, PA 15213-1516
RAND URL: http://www.rand.org/
To order RAND documents or to obtain additional information, contact
Distribution Services: Telephone: (310) 451-7002;
Fax: (310) 451-6915; Email: order@rand.org

Preface

About This Analysis

Each year, the Department of Energy (DOE) requires its research programs to estimate the benefits from their research activities. These estimates are part of the programs' annual budget submissions to the DOE, and they are also required under the Government Performance and Review Act. Each program in the DOE's Office of Energy Efficiency and Renewable Energy (EERE) is responsible for providing its own assessment of the impact of its technology research and development (R&D) programs. For the most part, the benefit estimates from each EERE program office are made at the national level, and the individual estimates are then integrated through the use of the National Energy Modeling System to generate an aggregate set of benefits from the EERE's various R&D programs.

At the request of the National Renewable Energy Laboratory (NREL), the RAND Corporation examined the relationship between energy demand and energy prices with the focus on whether the relationships between demand and price differ if these are examined at different levels of data resolution. In this case we compare national, regional, state, and electric utility levels of data resolution. This study is intended as a first step in helping NREL understand the impact that spatial disaggregation of data can have on estimating the impacts of their programs.

This report should be useful to analysts in NREL and other national laboratories, as well as to policy nationals at the national level. It may help them understand the complex relationships between demand and price and how these might vary across different locations in the United States.

The RAND Environment, Energy, and Economic Development Program

This research was conducted under the auspices of the Environment, Energy, and Economic Development Program (EEED) within RAND Infrastructure, Safety, and Environment (ISE), a unit of the RAND Corporation. The mission of RAND Infrastructure, Safety, and Environment is to improve the development, operation, use, and protection of society's essential man-made and natural assets and to enhance the related social assets of safety and security of individuals in transit and in their workplaces and community. The EEED research portfolio addresses environmental quality and regulation, energy resources and systems, water resources and systems, climate, natural hazards and disasters, and economic development both domestically and internationally. EEED research is conducted for government, foundations, and the private sector. Questions or comments about this report should be sent to the project leader, Mark Bernstein (mark_bernstein@rand.org). Information about the Environment, Energy, and Economic Development Program is available online (www.rand.org/ise/environ). Inquiries about EEED projects should be sent to the Program Director (ise_eeed@rand.org).

Table of Contents

Figures

Tables

Summary

The Department of Energy (DoE) Office of Energy Efficiency and Renewable Energy (EERE) has a portfolio of energy efficiency research and development programs that is intended to spur development of energy-efficient technologies. The goal of these programs is to decrease costs and improve efficiency of emerging technologies and increase the potential for consumers and businesses to adopt them. EERE, under requirements of the Government Performance Results Act (GPRA), must estimate the benefits of their portfolio of energy efficiency programs. With these estimates of benefits, EERE can then assess the cost-effectiveness of its programs and use this information in allocating its budget.

Currently, EERE estimates the benefits of its programs by analyzing their effects using the DoE's National Energy Modeling System (NEMS), a complex model of the U.S. energy system. Because the projected benefits of their programs depend heavily on the NEMS model, EERE is interested to know if certain assumptions in the NEMS model might impact the projected benefits. Specifically, the NEMS model uses data and parameters aggregated to the regional and national levels. If, for instance, the data or parameters used in the analysis actually vary considerably within a region, then NEMS will project biased results and using more disaggregated data—possibly at the state or utility level—could improve accuracy of the results. In this study, we examine how trends in several measures of the energy market may vary at the state and regional levels and in particular how one important parameter used in the NEMS model, price elasticity of demand (a measure of how demand responds to price), varies at the national, regional, state, and utility levels. With this initial examination, we offer some recommendations on whether EERE can improve their benefit estimates by using more disaggregated data in analysis of their programs.

Economic theory says that as energy prices rise, the quantity of energy demanded will fall, holding all other factors constant. Price elasticities are typically in the negative range, which indicates that demand falls as prices increase or, conversely, that demand increases as prices fall.

To determine if regional, state, or sub-state characteristics could affect the size of the impact from energy-efficiency technologies on energy prices, supply, and consumption, we looked at how individual factors—such as climate, supply constraints, energy costs, and demand for natural gas—might themselves affect the extent of the impact of energy efficiency.

Are There Regional Differences in the Price-Demand Relationship?

The object of this study is to determine whether the relationship between prices and demand differs at the regional, state, or sub-state level. In this study, we were interested solely in determining whether there are geographic differences in the price-demand relationship. We did not seek to understand how demand might impact prices and vice-versa, although some of our findings provide some insights into these issues. Our focus was on finding out whether the state- and regional-level differences were significant enough to recommend to the DOE that it should explore disaggregating its data by state or region when estimating the potential benefits of energy efficiency.

We examined three energy-demand components—electricity use in the residential sector, natural gas use in the residential sector, and electricity use in the commercial sector—at three or four levels of disaggregation of the data, depending on the availability of data. For each sector, we looked at national, regional, and state-level results. We also examined residential electricity use at the electric-utility level.

Our analysis indicates that there are regional and state differences in the price-demand relationship for electricity and natural gas. We did find, though, that there tends to be some consistency in residential electricity use among states within a region and visible differences between regions in demand and price trends, particularly for residential electricity use and less so for commercial electricity use or residential natural gas use. What this implies, for estimating the impact of energy-efficiency technologies, is that the DOE may have reason to explore differentiating the impacts of energy efficiency by region, at least for residential electricity. There does not seem to be a need, at least in the short run, for further disaggregation by geographic area, although more research is needed to offer a more conclusive recommendation.

We also found that the relationship between demand and price is small. That is, demand is relatively *inelastic* to price. We also found that in the past 20 years, this relationship has not changed significantly; analyses performed in the 1980s[1] showed approximately the same results. These findings might imply that there are few options available to the consumer in response to changes in the price of energy, and that price does not respond much to changes in demand. On the other hand, because prices were declining in real terms over most of the period we studied, the inelasticity of demand may be more of an artifact of the lack of price increases.

However, we now may be witnessing some changes in this area. The past few years have seen some increases in energy prices, with some states facing increasing electricity prices and all states facing increasing natural gas prices. While it is difficult statistically to uncover specific changes in trends, there are signs that demand growth has slowed, possibly due to a combination of increasing or flat prices and the economic slowdown of the past few years. Although we cannot say specifically that the relationship between price and demand might shift in an increasing-price environment, more analysis of recent trends may be warranted.

[1] Bohi, Douglas R., and Mary Beth Zimmerman, "An Update on Econometric Studies of Energy Demand Behavior," *Annual Review of Energy*, Vol. 9, 1984, pp. 105–154; Dahl, Carol A., "Do Gasoline Demand Elasticities Vary?" *Land Economics*, Vol. 58, No. 3, August 1982, pp. 373–382; and Dahl, Carol A. and Thomas Sterner, "Analyzing Gasoline Demand Elasticities: A Survey," *Energy Economics*, July 1991, pp. 203–210.

Acknowledgments

We would like to thank Doug Arent of the National Renewable Energy Laboratory for his efforts to fund this study and help guide the development of the analysis. Special thanks to Brian Unruh from the Department of Energy and David Loughran of RAND for their insightful reviews of the analysis and helping us focus the paper. We also appreciate conversations we had with Dan Relles on understanding some of the data issues. We appreciate assistance provided to us by staff at the Energy Information Administration, and finally thanks to Nancy DelFavero for assistance in editing.

Chapter 1: Introduction

The Department of Energy (DoE) Office of Energy Efficiency and Renewable Energy (EERE) has a portfolio of energy efficiency research and development programs that are intended to spur development of energy-efficient technologies. The goal of these programs is to decrease costs and improve efficiency of emerging technologies and increase the potential for consumers and business to adopt them. EERE, under requirements of the Government Performance Results Act (GPRA), must estimate the benefits of their portfolio of energy efficiency programs. With these estimates of benefits, EERE can then assess the cost-effectiveness of its programs and use this information in allocating its budget.

Currently, EERE estimates the benefits of its programs by analyzing their effects using the DoE's National Energy Modeling System (NEMS), a complex model of the U.S. energy system. To make the estimates, DoE runs the NEMS model with traditional assumptions about the energy system and uses the results to establish baseline estimates of energy use and prices. DoE then introduces into the model the changes to the energy system attributable to EERE's R&D programs and estimates a new set of energy demands and prices. EERE uses the differences in the two projections as estimates of the impacts of its programs.

Because the projected benefits of their programs depend heavily on the NEMS model, EERE is interested to know if certain assumptions in the NEMS model might impact the projected benefits. Specifically, the NEMS model uses data and parameters aggregated to the regional and national levels. If, for instance, the data or parameters used in the analysis actually vary considerably within a region, then NEMS estimates of the impacts of energy efficiency might be misstated. Using more disaggregated data—possibly at the state or utility level—could then improve accuracy of the results. In this study, we examine how trends in several measures of the energy market may vary at the state and regional levels and in particular how one important parameter used in the NEMS model, price elasticity of demand (a measure of how demand responds to price), varies at the national, regional, state, and utility levels. With this initial examination, we offer some recommendations on whether EERE can improve their benefit estimates by using more disaggregated data in analysis of their programs.

Geographic Variability in Energy Markets Could Affect DOE Benefit Estimates
Geographical variation in price-demand relationship and price elasticity has important implications for the benefit estimates of EERE's programs. The NEMS model represents energy demand and supply at the regional level and uses one price elasticity for all regions. If energy markets vary substantially at the sub-regional level or if price elasticities vary across the country, then estimates of the impacts of energy efficiency technologies will vary by region and this will not be reflected I the NEMS runs.

Economic theory says that as energy prices rise, the quantity of energy demanded will fall, holding all other factors constant. Economic theory also suggests that consumers' demand for energy is less sensitive to price changes than the demand for many other commodities. Economists define consumers' sensitivity to price changes as a measure of *price elasticity.* Price elasticity is calculated as follows:

$$\text{Price Elasticity} = \frac{\%\Delta QuantityDemanded}{\%\Delta \Pr ice}$$

In this equation, the numerator and denominator are expressed as a percentage of change. Because price elasticity is a ratio of two percentages, it is not expressed as a specific unit of measure and can be compared across different commodities.

Price elasticities are typically in the negative range, which indicates that demand falls as prices increase or, conversely, that demand increases as prices fall. Demand elasticities are of two types, *inelastic* and *elastic,* and the range of each type differs. The range of inelastic demand is within absolute values of 0 to 1, and the elastic range begins with values greater than 1. These terms can be interpreted intuitively. A commodity with inelastic demand has a less than proportional change in demand for a given change in the price for the commodity. For instance, if prices increase by 10 percent on a good with a price elasticity of –0.20, then demand for the good drops by only 2 percent. In the elastic range, consumer demand responds with a greater-than-proportional change for a given price change. For instance, a good with an elasticity of –1.5 would have a 15 percent drop in demand with a 10 percent increase in price. This relationship is pictured in Figure 1.1.

The figure shows a conventional supply curve (S_1) and two demand curves with different elasticities (D_1 and D'_1). D_1 is less elastic (i.e. steeper) than D'_1. At equilibrium, both demand curves intersect the supply curve at the same point, with price at P1 and quantity at Q_1.

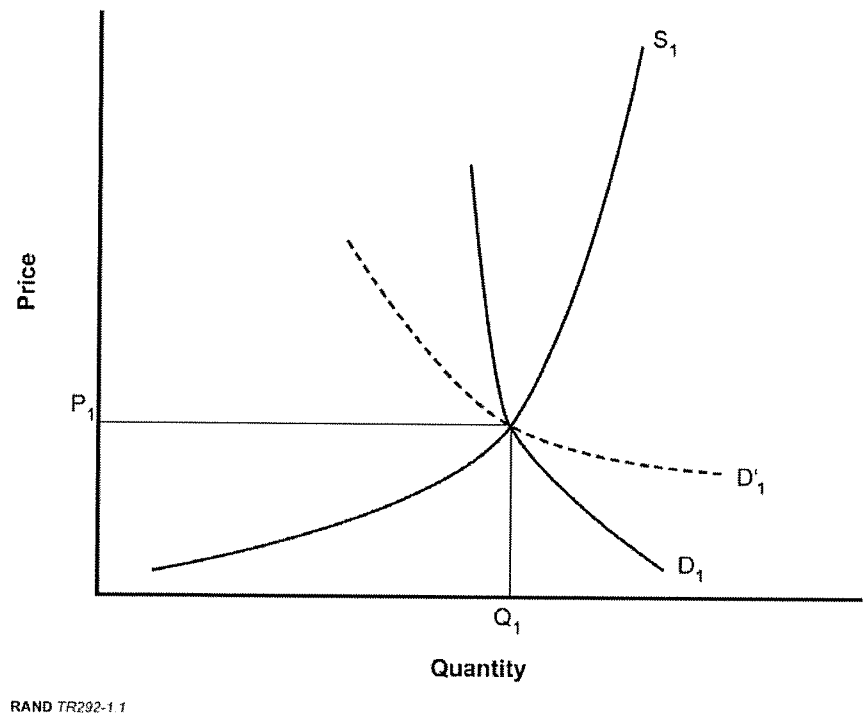


Figure 1.1: Relationship of supply and demand with two different demand curves

If the supply curve shifts inward, which could represent an increase in the price of a fuel used to produce electricity such as natural gas, the new equilibrium point would depend on which demand curve is used as demonstrated in Figure 1.2. If the demand curve is relatively inelastic (D_1) then prices would rise and there would be only a small reduction in demand (P_2, Q2). With the more elastic demand curve (D'_1), both the equilibrium price and the quantity are lower than the more inelastic curve (P'$_2$,Q'$_2$). In the end, the difference in the equilibriums would depend on the magnitude in the variation between the elasticities.

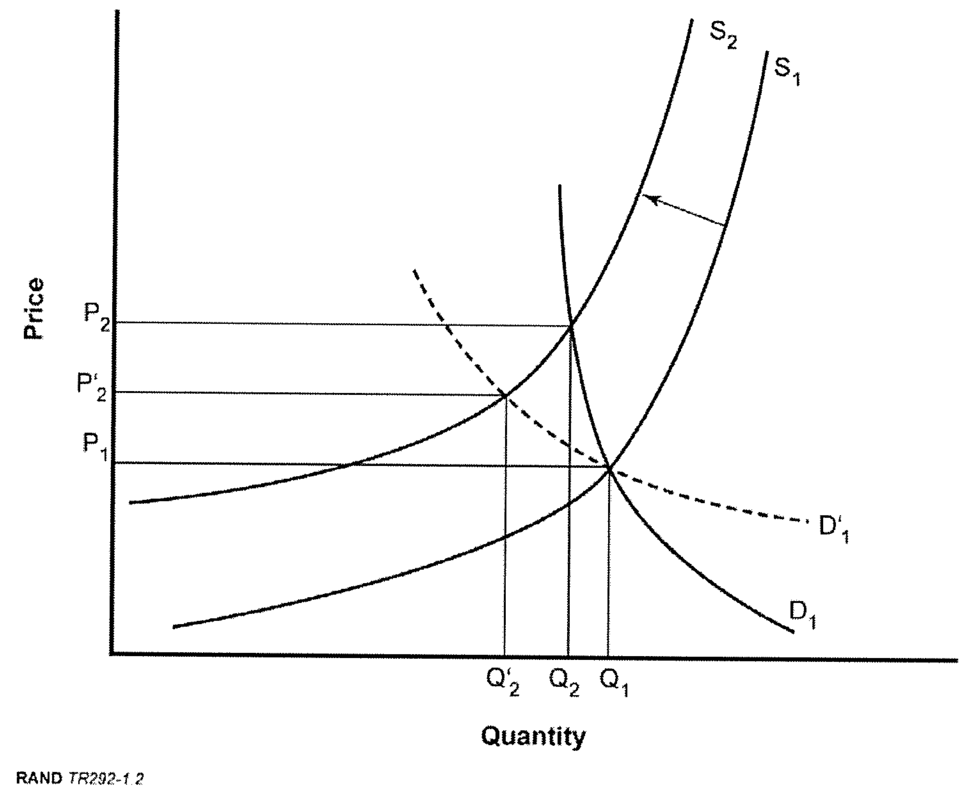
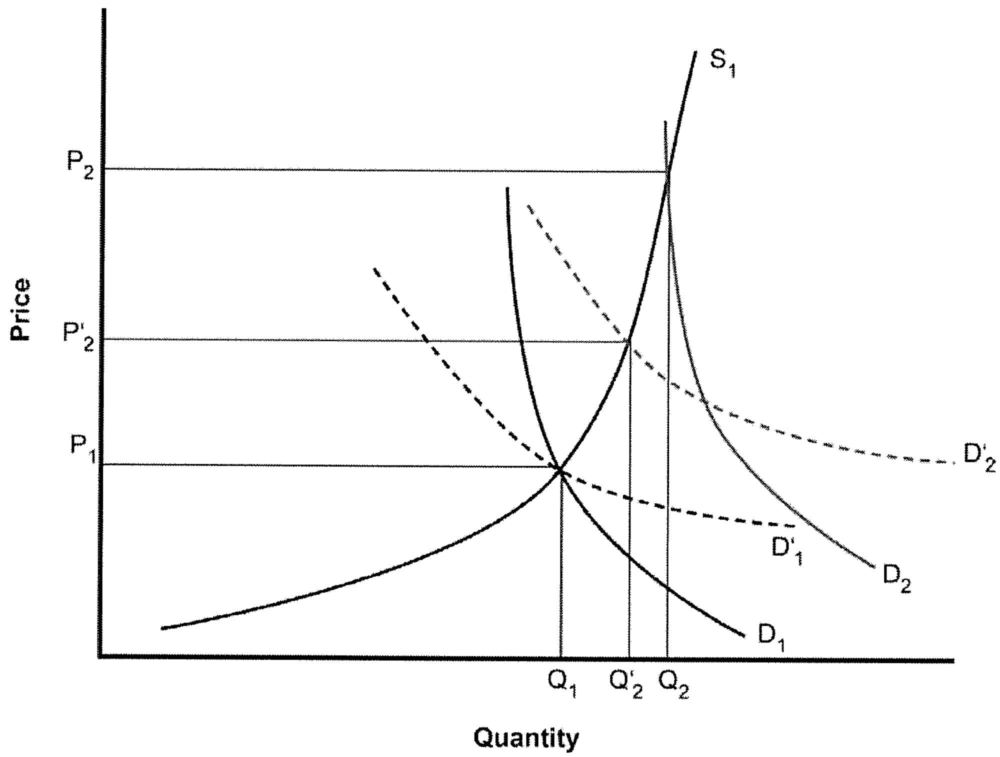


Figure 1.2: Impact of a shift in the supply curve

The price elasticity will also impact results if changes in demand are expected. In figure 1.3 we show the impact on price and quantity of a shift in the demand curve. In this case let's say demand increases – so the curve shifts outward from D_1 to D_2. If the supply does not change, with a less elastic demand curve the prices and quantity would be higher (P_2, Q_2) than if the demand curve was elastic (P'$_2$, Q'$_2$). Since energy efficiency impacts demand first, this picture is very relevant for EERE analysis. The impacts on price and quantity of changes in demand will certainly be different with different elasticities.



RAND *TR292-1.3*

Figure 1.3: Impact of a shift in the demand curve

Price elasticities can be used to interpret how consumer demand responds to price changes. They also indicate how readily consumers can purchase substitutes for a product that has gone up in price and how much consumers value a particular good. Price elasticities can be used in this way because of the underlying theory of consumer response to price changes. A consumer with a fixed budget in the short term has three possible responses to a price change: (1) The consumer can buy another good as a substitute; (2) the consumer can buy less of the good with no corresponding purchase of a substitute; or (3) the consumer can continue to purchase the same amount of the good and reduce expenditures on other goods in his or her consumer bundle.

In the case of electricity and natural gas (the focus of this study), these commodities have a limited degree of substitutability, especially in the short term. For end uses such as home heating and cooking, consumers can switch between energy-using systems that use electricity or natural gas. However, the consumer may want to purchase a new appliance that uses the less-expensive energy source. In other uses, such as a power supply for a computer, electricity has no substitutes. Nevertheless, the consumer still has the option to purchase a more efficient computer and enjoy the same level of service using less electricity. Typically, purchasing a more efficient appliance or one that uses a different type of fuel requires replacing a relatively expensive item, like a computer or refrigerator, and is considered a long-run adjustment by the consumer to high energy prices.

Based on this analysis, consumer demand for electricity and natural gas should be relatively unresponsive to price changes in the short term and more responsive to price changes in the long term but could differ substantially by region. Demand for these goods is generally inelastic in the short term, because a consumer's main options when energy prices change are to vary how he or she uses energy-consuming appliances (e.g., adjust a thermostat or turn on fewer lights) or reduce expenditures on other goods. Over the longer term, consumers can buy appliances that use a different energy source and/or purchase more-efficient appliances. Therefore, price elasticities tend more toward the elastic range than the inelastic range in the long term.

One of the important benefit measures for the EERE programs is the projected energy savings from the energy efficiency programs. The diagrams above show that estimating the impacts on demand depends on the price elasticities used in the analysis. Therefore, if elasticities differ between regions, the model needs to include geographical variation in price elasticities to make accurate estimates. The following sections will discuss possible reasons for geographic variation in price elasticities and the relationship between energy efficient technologies and price elasticity.

Relationship Between Energy Efficiency and Price Elasticity

Energy-efficient technologies provide a substitute for energy consumption when energy prices increase, which has important implications for the price elasticity of demand in energy markets. The price-elasticity of demand measures the percentage change in the amount demanded given a percentage change in the price of a good. Overall, this measure reflects the value of a good to consumers and the availability of substitutes.

For the goods considered in this study, electricity and natural gas, the availability and cost of substitutes vary throughout the country. Constraints in infrastructure cause some of the differences in availability. For instance, the states of Maine and Florida have limited capacity for natural gas. Therefore, natural gas is a more costly substitute for electricity in these states relative to most others. In some cases, policy can drive differences in the cost of substitutes. Many states have programs to subsidize adoption of energy-efficient technologies, which also creates geographic differences in the cost of a substitute to electricity and natural gas. Both cases may cause price elasticities to vary across the country.

The preceding discussion provided reasons why the price elasticity of demand may vary and it suggests the direction that price elasticities could change. In areas where the costs of substitutes are competitive, price elasticities may increase in absolute magnitude (become more elastic) because consumers could more easily switch to substitutes as prices increase. Locations where particular energy uses are very valuable, such as air conditioning in southern states or winter heating in northern states, could have price elasticities smaller in absolute magnitude (more inelastic) because air conditioning and heating are so valuable during periods of extreme climate that consumers are unwilling to change their use when prices change. Again, both of these driving factors, the cost of substitutes and value of energy uses, vary geographically, which suggests price elasticity may differ across the country.

Analytical Approach

In this study, we analyzed energy demand for three markets—residential electricity, commercial electricity, and residential natural gas—and geographical variation in energy markets by region, state, and utility (for residential electricity). We assessed how trends in energy intensity, per capita energy expenditures, and expenditures as a share of income varied across the country. And, since the NEMS model currently uses one national value for price elasticity and the preceding discussion suggested some reasons why price elasticity might differ geographically, a primary focus of the study was to analyze if price elasticities vary at the regional, state, and utility levels. These analyses will help EERE evaluate whether they need to use more disaggregated analysis in estimating the benefits of their programs.

Summary of Findings

Our analysis indicates that there are significant regional and state differences in the price-demand relationship for residential electricity and less so for commercial electricity and for residential natural gas. We did find, though, that there tends to be some consistency among states within a region and visible differences between regions in consumption and price trends. This tendency seems to be particularly strong for residential electricity use. It is possible that this relationship is more significant for residential electricity because some electricity uses in the home may be more discretionary than commercial or natural gas uses. Some electric using appliances can be used less, lights can be switched off and more efficient bulbs used. Most commercial business has limited availability to alter electricity sue in the short run, and residential natural gas use which is primarily for water heating, cooking and heating has less potential for modifications.

The results imply that the DOE may have reason to explore differentiating the impacts of energy efficiency by region, at least for residential electricity. There does not seem to be a need, at least in the short run, for further disaggregation by geographic area in the two other energy markets, although more research is needed to offer a more conclusive recommendation.

We also found that the relationship between consumption and price is small. That is, demand is relatively *inelastic* to price. We also found that in the past 20 years, this relationship has not changed significantly; analyses performed in the 1980s[2] showed approximately the same results. These findings might imply that there are few options available to the consumer in response to changes in the price of energy, and that price does not respond much to changes in demand. On the other hand, because prices were

[2] Bohi, Douglas R., and Mary Beth Zimmerman, "An Update on Econometric Studies of Energy Demand Behavior," *Annual Review of Energy*, Vol. 9, 1984, pp. 105-154; Dahl, Carol A., "Do Gasoline Demand Elasticities Vary?" *Land Economics*, Vol. 58, No. 3, August 1982, pp. 373-382; and Dahl, Carol A. and Thomas Sterner, "Analyzing Gasoline Demand Elasticities: A Survey," *Energy Economics*, July 1991, pp. 203-210.

declining in real terms over most of the period we studied, the inelasticity of demand may be more of an artifact of the lack of price increases.

However, we now may be witnessing some changes in this area. In the past few years, energy prices have increased with some states facing increasing electricity prices and all states facing increasing natural gas prices. While it is difficult statistically to uncover specific changes in trends, there are signs that demand growth has slowed, possibly due to a combination of increasing or flat prices and the economic slowdown of the past few years. Although we cannot say specifically that the relationship between price and demand might shift in an increasing-price environment, more analysis on recent trends may be warranted.

Organization of This Report

In Chapter Two, we provide a brief overview of 30 years of literature on the energy price-demand relationship and past attempts to estimate price elasticity. We then follow with an explanation of the methodology we used in this study. Chapters Three through Six present the study results in order by increasing levels of disaggregation of data—national-level analysis in Chapter Three, regional-level analysis in Chapter Four, state-level analysis in Chapter Five, and utility-level analysis for the residential electricity sector in Chapter Six, Chapter Seven presents the conclusions derived from the results of the study, implications for the DOE and for federal energy-efficiency policy, and thoughts for next steps on research topics. The appendixes present methodological details and our data sources.

Chapter 2: Economic Theory, Literature, and Methodological Approach

In this chapter, we present information that we used in producing our findings on energy price-demand relationships and the comparative impacts from energy efficiency at the national, regional, state, and utility levels. We first provide an overview of some of the literature on energy demand, and then describe the model we used to estimate energy demand.

Previous Literature on Energy Demand

Previous studies have found that energy demand is inelastic in the short run but more elastic in the long run. Several studies also found that price elasticities varied across locations, but the same general pattern remained (inelastic demand in the short run and more-elastic demand in the long run). The energy-demand literature consists of several dozen papers and is too voluminous to describe here in detail. Therefore, this section focuses on a representative handful of survey articles on this subject.

Taylor (1975) completed one of the first literature surveys on electricity demand. He reviewed the existing studies on residential, commercial, and industrial electricity demand. For residential electricity, he reported that short-run price elasticities varied from –0.90 to –0.13. Long-run price elasticities ranged from –2.00 to near zero. The only study of commercial price elasticities that differentiated between long-run and short-run elasticities observed a short-run price elasticity of –0.17 and a long run elasticity of –1.36.

Bohi and Zimmerman (1984) conducted another comprehensive review of studies on energy demand. They surveyed the existing research on demand in the residential, commercial, and industrial sectors for electricity, natural gas, and fuel oil. They also reviewed studies on gasoline demand. Bohi and Zimmerman found that the consensus estimates for residential electricity price elasticities was –0.2 in the short run and –0.7 in the long run. They reported that the range of estimates in commercial electricity was too variable to make conclusions about consensus values. For residential natural gas consumption, they reported consensus values of –0.2 in the short run and –0.3 in the long run.

Bohi and Zimmerman also concluded that the energy price shocks of the 1970s did not change the structural characteristics of consumer demand. The studies they reviewed include studies from before and after the energy-price shocks in 1974 and 1979. They compared studies from the pre– and post–price-shock periods and also reported findings from studies that had divided study samples across the various periods to determine if any structural changes occurred in energy demand. One hypothesis they tested is that demand may become more elastic at higher price levels. Another hypothesis they tested is that rapid price changes sensitize consumers to energy demand, causing consumers to change their habits to conserve more energy.

Bohi and Zimmerman did not find much evidence to support their hypotheses. The estimated price elasticities from studies before and after the price shocks of the 1970s do not differ substantially. However, the authors could not use statistical tests of significance to evaluate the differences between price elasticities. In addition, several studies reviewed by Bohi and Zimmerman tested whether the price shocks changed the structural characteristics of the energy demand equation used to estimate elasticities. They found that energy demand decreased significantly after the price shocks. But, their analyses did not reveal any change to the structural characteristics of the energy demand equation.

Dahl and Sterner (1991) conducted a comprehensive review of the literature on gasoline demand (gasoline demand was not included in our study due to lack of available data). However, their review found consensus estimates on price elasticities. Dahl and Sterner concluded that the average short-run price elasticity was –0.24, and the average long-run price elasticity was –0.80.

Several previous studies also examined whether energy-price elasticity varied across locations. Houthakker et al. (1974) estimated price elasticities for residential electricity and gasoline and found that elasticities varied across states. They also found some correlation between price elasticity and degree of urbanization. Elasticities generally became more elastic as the degree of urbanism decreases, except for the most-rural states, which had a positive elasticity for both gasoline and residential electricity demand. Houthakker et al. did not offer an explanation for this pattern, especially the positive elasticity for the most-rural states.

Maddala et al. (1997) estimated price elasticities in 49 U.S. states (excluding Hawaii) and found variation across states. The mean of the estimates was –0.16. The minimum was –0.28, and the maximum was –0.06. In the long run, the mean was –0.24, with a minimum of –0.87 and a maximum of 0.24.

Garcia-Cerrutti (2000) estimated price elasticities for residential electricity and natural gas demand at the county level in California. For residential electricity, the estimate of the mean was –0.17, with a minimum of –0.79 and a maximum of 0.01.

In summary, previous studies show that price elasticities are generally inelastic in the short run and more elastic in the long run. Further, elasticities vary at the state and county levels; however, the same general pattern of inelastic demand in the short run and more elastic demand in the long run still holds.

Estimation Approach

For this study, we used a dynamic demand model developed by Houthakker et al. (1974). This model estimates long-run and short-run energy demand by using lagged values of the dependent variable along with current and lagged values of energy prices, population, economic growth/per capita income, and climate variation. The model estimates short-run demand using energy prices and quantity demanded in the current period, and it estimates long-run demand through changes in the stock of energy-consuming appliances reflected by the lagged dependent variable. The technical details of the model and the process for making adjustments to reflect long-term demand are described in Appendix A.

We used state-level panel data on residential and commercial electricity consumption and residential natural gas consumption in the 48 contiguous U.S. states. The residential electricity and natural-gas data span 1977 through 2004. The commercial electricity data include only the years 1977 through 1999 because of limitations in economic data available from the Bureau of Economic Analysis. We also used a dataset on residential electricity consumption at the utility level from 1989 through 1999. The state energy data are from the DOE Energy Information Administration's (EIA) *Electric Power Annual* (see Appendix B for details). This publication contains data on electricity consumption and prices by energy-using sector. The natural gas data are from a "U.S. Gas Prices" table on the EIA's Natural Gas Navigator Web site.[3] Finally, the utility data set comes from data reported to the DOE on form EIA-861. Submission of this form is a mandatory reporting requirement for utilities in the United States. The data on demographic and economic variables are from the Bureau of Economic Analysis in the Department of Commerce (again, see Appendix B for details).

The analysis uses a fixed-effects model, which controls for time effects, and a set of covariates. The location-specific price elasticity estimates come from interaction terms in the model between a location-indicator variable (region, state, or utility) and the variable of interest (price or lagged quantity). The estimates on the interaction terms indicate any differences between locations in the sample. The final elasticity estimates for each state are the sum of the estimate of the main effect and the interaction term for the location. The analysis uses hypothesis tests to determine if individual estimates are significantly different from zero and if a location is significantly different from the other locations.

We estimate this model using the following fixed-effect specification:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

[3] Current data on the Web site can be found at table can be found at http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

where $Q^D_{i,t}$ is log energy demand in state *i* and year *t*, $Q^D_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g., energy prices, population, income, or climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The residual has three components:

- s_i is an indicator variable that captures time-invariant differences in energy demand across states ("state fixed effects").
- y_t is an indicator variable that captures time effects common to all states ("year fixed effects").
- $\varepsilon_{i,t}$ is a random error term.

We estimate any spatial differences in the energy demand relationship by adding interaction terms between the region or state indicator variables and the regressors of interest (price, quantity, and income). These interaction terms allow the estimated parameters to vary for each region or state, and we can then determine whether price elasticities differ across geographical units.

The fixed-effects model controls for state-specific time-invariant factors that could bias the parameter estimates. The year effects in the model control for any time effects common to all states in a particular year, which could bias the parameter estimates. These effects control for many potential sources of bias. However, the fixed and year effects do not control for state-specific factors that vary through time. If any of these factors are correlated with explanatory variables and also affect energy demand, then the regression will have biased estimates.

The fixed-effects model controls for effects specific to each state or utility that do not vary through time. An example of such a fixed effect is abundant energy supplies in certain states, such as hydroelectric power in the Pacific Northwest states or coal in West Virginia. This is a fixed effect because the states have those resources due to geographical factors that cannot change in the sample period. These states also tend to have much lower energy prices than other states. The fixed-effects model controls for this particular state-specific effect that does not vary through time and all other fixed effects that may or may not be measurable. Without controlling for these effects, the effects would bias the results. Appendix A explains the fixed-effects model in more detail.

The model also controls for time trends that affect all the states uniformly. An example of a time trend would be the enactment of a new energy-related law or a change in the majority political party in Congress. These factors have a constant, national effect, for which the model can control using indicator variables for each year.

The next four chapters present an overview of the results of our analysis of how energy prices and demand interact for residential electricity and natural gas and for commercial electricity. Details of all the results are presented in Appendix D. Because the purpose of this study is to see whether the price-demand relationship differs at the regional or state level, we present the results in descending order of dissaggregation—national, then regional, then state, and finally utility-level results. Within the chapters, we first discuss residential electricity, then commercial electricity, and then residential natural gas.

Chapter 3: National-Level Results

Residential Electricity Use

Real electricity prices peaked in the early 1980s in the United States and steadily declined until 2000–2001 (see Figure 3.1). In 2001, average electricity prices increased in many states, and the figure shows a slight price rise over the past two years in the period studied. The figure also shows that residential electricity demand rose steadily during this period, although it appears that demand growth may have slowed after 2002. The long-term trend is an average annual increase in demand of approximately 2.6 percent.

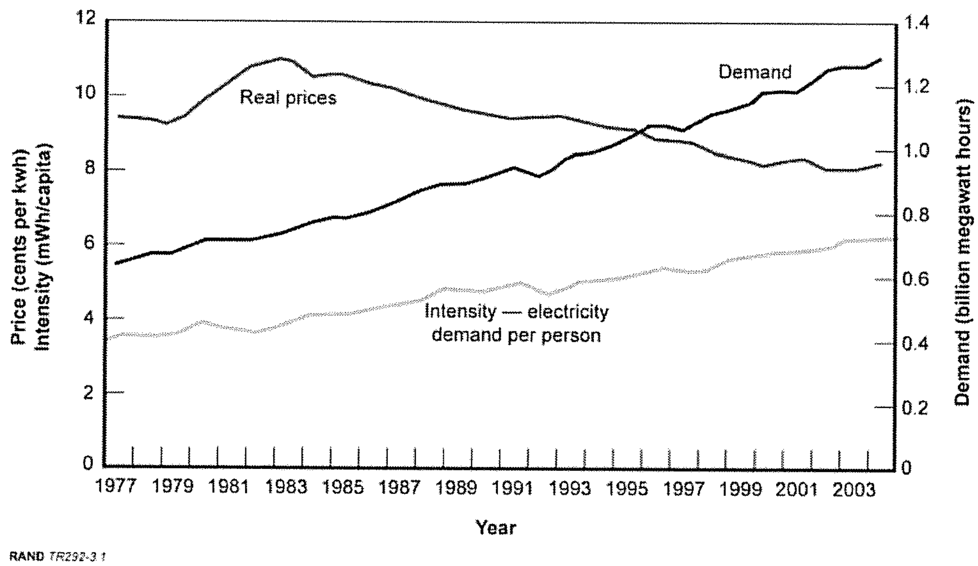


Figure 3.1: Residential Electricity Prices, Demand, and Intensity, 1977–2003

There also was a steady increase in *intensity* (i.e., per-capita residential electricity use) until 2002. The long-term trend in the time series is an average annual increase of 1.5 percent. Per-capita residential electricity seems to have leveled out over the past few years of the period, perhaps due to the flattening of prices and the post-9/11 recession.

To generate values of the price-demand relationship that we could compare across regions and states, we use the functional form described in Chapter Two for estimating the price elasticity for residential electricity. Table 3.1 displays the results of our regression analysis for the residential electricity sector. It presents the coefficients from the regression analysis and notes whether the variable is significant. The dependent variable is residential electricity demand. The data points represent each state for each year in the sample. The independent variables are electricity demand in the previous year; average real electricity price in the current and previous years; residential disposable income in the current and previous years; population in the current and previous year; natural gas price in the current and previous years; and climate measured as heating and cooling degree days (see Appendix A for a definition of *degree days*). Definitions of the variables are presented in more detail in Appendix C. Details of the regressions are in Appendix D.

These estimates reflect national-level values.

Table 3.1: Results of Regression Analysis of Residential Electricity Demand, 1977–2004

Variable	Coefficient	Statistically Significant
Electricity demand in previous year	.232	Yes
Electricity price in current year	-.243	Yes
Electricity price in previous year	-.129	Yes
Income in current year	.003	No
Income in previous year	.384	Yes
Population in current year	-.225	No
Population in previous year	.827	Yes
Natural gas price in current year	-.005	No
Natural gas price in previous year	.111	Yes
Climate – heating and cooling degree-days	.246	Yes

The table shows that the estimated short-run price elasticity is –0.2, which is statistically significant. The estimated long-run price elasticity is –0.32, and this value is also statistically significant. These estimates are consistent with results from the studies of residential electricity elasticity, cited in Chapter Two, which were conducted with data from earlier years. The survey literature concluded that the residential short-run elasticity was near 0.2.

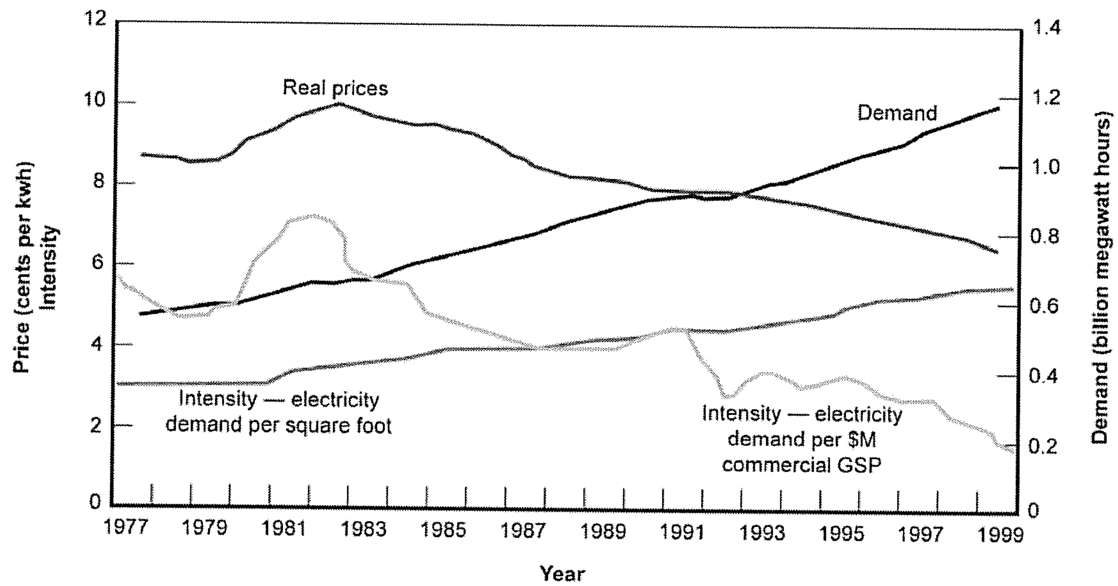
The results also generally show that, except for price, the current-year variables are not significant, but the lagged or previous-year variables are statistically significant, suggesting that demand for electricity responds after changes occur in factors that influence the demand. For example, a consumer's level of income does not seem to impact demand in the same year, but income from one year seems to impact demand in the following year. This essentially means that change in income over time impacts electricity use, and growing incomes lead to increasing electricity use. Population growth has a similar effect. Natural gas prices have an expected result—increasing natural gas prices one year lead to increasing electricity demand in the following year. This pattern would reflect cases in which people switch from natural gas to electricity for some energy-consuming applications, such as heating or cooking. Finally, the more heating and cooling degree days there are, the higher the demand for electricity.

None of these results are unexpected, although what might be somewhat surprising is that the basic magnitude of these results has not changed in the past 20 to 30 years. Previous analyses done in the late 1980s and early 1990s showed just about the same results.

Commercial Electricity

We next examine the price-demand relationship for use of electricity by the commercial sector. Some commercial-sector electricity data exhibit trends similar those seen in the residential-sector data (see Figure 3.2). Real prices of electricity peaked in the early 1980s and steadily decreased through the period studied. Demand consistently increased throughout the study period. The average annual growth in demand during the period was 3.4 percent. Because the data we have for the commercial sector go only to the year 2000, we do not display recent price increases and do not know how they might have impacted demand.

In Figure 3.2, we show two pictures of commercial electricity intensity. One is electricity demand in mWh per dollar of commercial gross state product (GSP)—i.e., the size of the commercial electricity sector in economic terms. By this measure, electricity use has declined as a ratio of electricity demand to economic output from the commercial sector.



RAND TR292-3.2

Figure 3.2: Commercial Electricity Prices, Demand, and Intensity, 1977–1999

The other measure of intensity is electricity use per available square feet of space in the commercial sector. By this measure, electric intensity has increased over the period, reflecting the rapid growth in demand. This trend implies that the commercial sector, while getting more productivity out of electricity on a per-dollar basis, is continuing to add electricity loads to buildings, despite the fact that significant amounts of new, and ostensibly more-efficient, commercial space was added over the last few years of the period illustrated in the figure.

The relationship among demand, price, and other factors in the commercial sector has some similarities to the relationship among demand, price, and other factors in the residential sector and also some significant differences. Table 3.2 displays the regression analysis results for a regression with the dependent variable being commercial electricity demand. The independent variables have a similar construct as the residential model—demand in the previous year; prices in the current and previous year; GSP for the commercial sector (i.e., income) in the current and previous year; office-space measures in square feet in the current and previous year; natural gas prices; and climate.

The commercial electricity regression estimates are also consistent with estimates cited in Chapter Two. The short-run price elasticity is –0.21, and the long-run price elasticity estimate is –0.97. Previous studies found short-run elasticities somewhere around –0.2. Long-run elasticities were more variable, and the survey literature did not report consensus values for long-run elasticities. Our long-run estimate of –0.97 is within the consensus range for residential electricity and natural-gas demand, however.

Table 3.2: Regression Analysis Results for Commercial Electricity Demand

Variable	Coefficient	Statistically Significant
Electricity demand in previous year	.785	Yes
Electricity price in current year	-.209	Yes
Electricity price in previous year	-.148	Yes
Commercial GSP in current year	.155	No
Commercial GSP in previous year	-.039	No
New floor space in current year	.504	No
New floor space in previous year	-.421	No
Natural gas price in current year	-.023	No
Natural gas price in previous year	.049	Yes
Climate – heating and cooling degree-days	.246	Yes

Interestingly, of the many of the factors that we thought should impact electricity demand in the commercial sector, commercial economic output (i.e., GSP) and floor space turned out to be not significant.

Natural Gas

The patterns for residential natural-gas demand differ from those in the electricity markets (see Figure 3.3). Prices peaked in the early 1980s and then again after 2001. Demand for natural gas in the short term is more variable than demand for electricity in the short term, and there is no real growth in demand over the period that was studied, and a recent downward trend perhaps reflects increased prices.

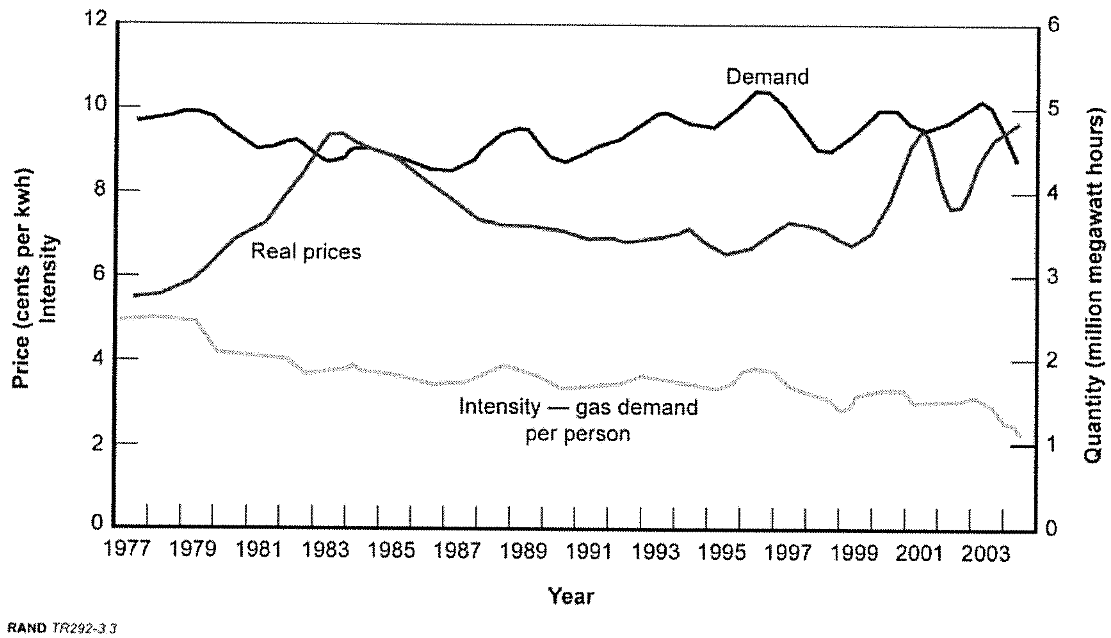


Figure 3.3: Residential Natural Gas Prices, Demand, and Intensity, 1977–2003

In contrast to residential electricity intensity, natural gas intensity declined during this period. The long-term trend during this period was a 0.9 percent decline in intensity (defined for this sector as demand per capita for natural gas), reflecting some improved energy efficiency and some substitutions away from natural gas.

The regression estimates also differ from those for the electricity market (see Table 3.2). Table 3.3 shows regression results, with the dependent variable being residential natural gas prices and the same variables as were used for the residential electricity regression. The short-term price elasticity is –0.12, and long-term price elasticity is –0.36. Bohi and Zimmerman (1984) reported consensus values of –0.2 in the short term and –0.3 in the long term. These values may reflect the fact that there are fewer opportunities for consumers to reduce their demand for natural gas in response to price, possibly because the use of natural gas in the home (i.e., for air and water heating and cooking) is a necessity, whereas turning off some lights or using fewer electric appliances is optional.

Table 3.3: Regression Analysis Results for Residential Natural Gas Demand

Variable	Coefficient	Statistically Significant
Natural gas demand in previous year	.67	Yes
Natural gas price in current year	-.12	Yes
Natural gas price in previous year	-.08	Yes
Electricity price in current year	.03	No
Electricity price in previous year	.11	Yes
Income in current year	.24	Yes
Income in previous year	.07	No
Population in current year	1.18	Yes
Population in previous year	-.86	Yes
Climate – heating and cooling degree-days	.27	Yes

The natural gas results differ from those for electricity. Income in the current year is a significant factor in demand for natural gas, whereas income in the previous year is not. The reason that previous-year income is significant for electricity could be because increased income might lead to consumers buying new appliances that add to the electrical load in the following year. In the case of natural gas, by comparison, there a that increased income might lead to consumers turning up the thermostat in the winter, adding to their current-year natural-gas consumption. The impact of electricity price on natural gas demand in the previous year is consistent with what we saw with the impact of natural gas price on electricity demand.

Summary of National-Level Results

As we have seen in this chapter, there are similarities and differences between the patterns of demand and price when comparing residential electricity, residential natural gas, and commercial electricity. Residential electricity use and intensity increased over the period we studied, although recent electricity price increases have slowed the growth of demand. Natural gas use has been flat, and intensity has declined, and we might see a greater decline due to recent natural-gas price increases. Commercial electricity use grew rapidly over the period studied, and while electricity as a share of output in the commercial sector has declined, electricity use per square foot of office space has continued to increase. A comparison of estimated price elasticities for the three sectors is presented in the Table 3.4.

Table 3.4: Price Elasticities for Residential Electricity, Commercial Electricity, and Residential Natural Gas at the National Level

	Residential Electricity	Commercial Electricity	Residential Natural Gas
Short-run elasticity	-.24	-.21	-.12
Long-run elasticity	-.32	-.97	-.36

Short-run price elasticities for electricity are similar for residential and commercial demand, although it appears that changes in commercial electricity price can have a bigger impact in the long term than in the short term. In the short run, natural gas demand is less elastic than demand for electricity but is about the same in the long run.

We used the national-level information presented in this chapter as a starting point for determining whether elasticities differ significantly among regions and states. The next chapter describes the regional-level results.

Chapter 4: Regional Results

This chapter describes the results from our analysis of trends in the three energy markets (residential electricity, commercial electricity, and residential natural gas) at the regional level. The analysis uses the nine census divisions that the DOE Energy Information Agency uses in energy modeling and forecasting: New England, Mid-Atlantic, South Atlantic, East North Central, East South Central, West North Central, West South Central, Mountain, and Pacific (see Figure 4.1).[4]

Figure 4.1: DOE Energy Information Agency Census Regions

In this analysis, we look at regional trends in energy intensity, energy expenditures, and expenditures as a share of income to determine if they differ among regions. We then

[4] We excluded Alaska and Hawaii from our analysis because they are unique in their energy uses and climate.

reproduce the regressions shown in the national-level analysis in Chapter Three to determine if there are significant differences in the price elasticities among regions.

Residential Electricity

Of the three markets that we examined in this study, residential electricity shows the most regional differentiation. Figures 4.2, 4.3, and 4.4 display trends in residential electricity use, expenditures, and expenditures as a share of total income, respectively, for the nine DOE census regions. The Figure 4.2 shows regional trends in per-capita residential electricity intensity.

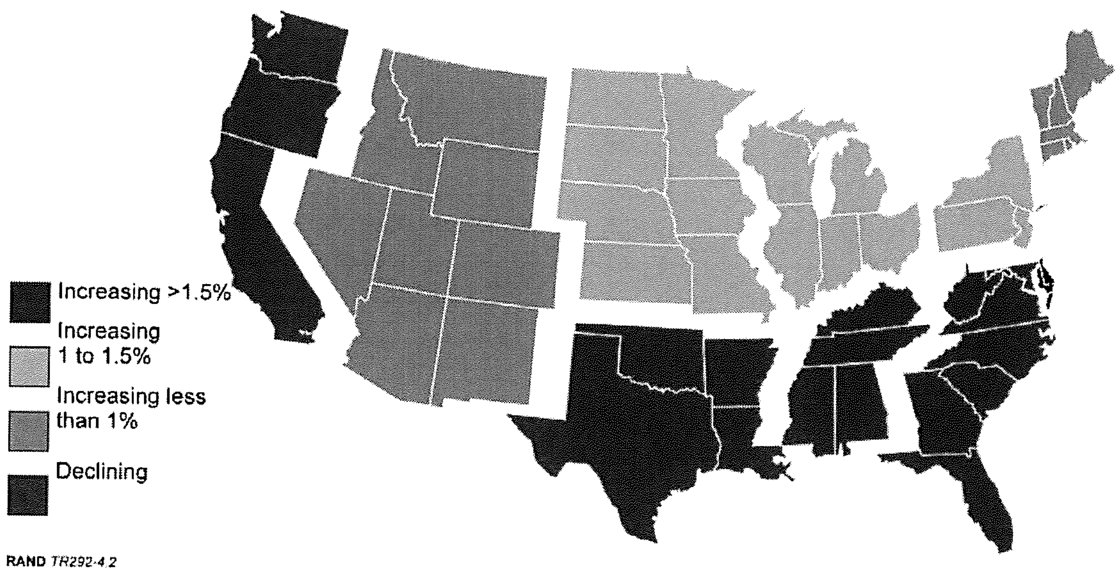


Figure 4.2: Regional Trends in Per-Capita Residential Electricity-Intensity, 1977–2004

Figure 4.2 shows four categories of trends in intensity–increasing over the period more than 1.5 percent on average, increasing between 1 percent and 1.5 percent per year on average, increasing less than 1 percent, or declining. Only one region had declining electricity intensity--the Pacific. Residential electricity intensity is growing fastest in the South Atlantic and East South Central regions. The Middle Atlantic, East North Central, and West North Central regions have the next-fastest growth rates. New England and the Mountain states have growth rates of less than 1 percent.

It is interesting to note that some commonality exists across contiguous regions. The East South Central, West South Central, and South Atlantic regions have experienced the most-rapid growth in electricity intensity, perhaps driven by air-conditioning loads and rapidly growing populations. The Middle Atlantic and West North Central regions also have had increasing air-conditioning loads at levels that did not exist until the late 1980s, and they have seen relatively rapid growth in electricity intensity over this period.

The Pacific Coast, which is dominated by California in its magnitude of electricity use, has had declining electricity intensity, possibly due to energy-related building codes that are the strictest in the nation and have been in place longer than any others.

All of these findings might imply that the impact of energy efficiency would be greater in areas such as the South in which the intensity of electricity use has been growing more rapidly than in other regions and might have less of an impact in the Pacific Coast where intensity has been declining.

Figure 4.3 shows growth trends for average expenditures on residential electricity. The figure shows that average expenditures on residential electricity are growing in all regions but provides a different picture than residential electricity intensity. Expenditures are growing most rapidly in the South Atlantic, East South Central, New England, and Pacific Coast regions. The Middle Atlantic and West South Central regions have the next-fastest growth rate, while the Mountain, East North Central, and West North Central regions have the slowest growth rates.

In a demand-price relationship, one might expect to see a picture similar to the one for electricity intensity--those areas with the most rapid increases in expenditures would have declining or slower growth in electricity intensity. While this is true for the Pacific states and Northeast, the opposite is true for the South Atlantic and East South Central regions. This is the first indication that the regional differences in the demand-price relationship might matter when estimating the impact of energy efficiency on other demand changes.

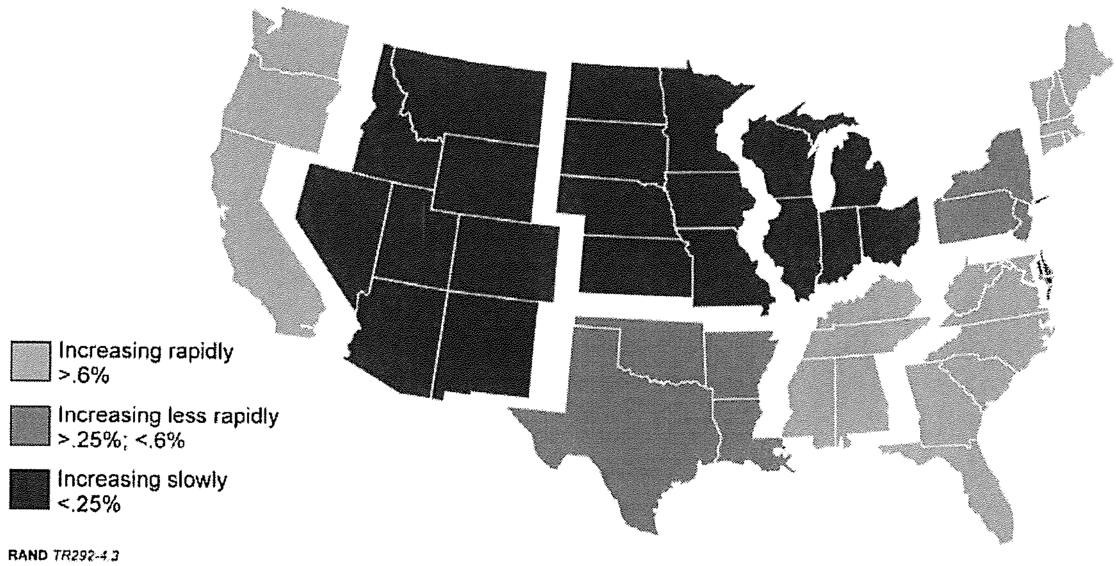
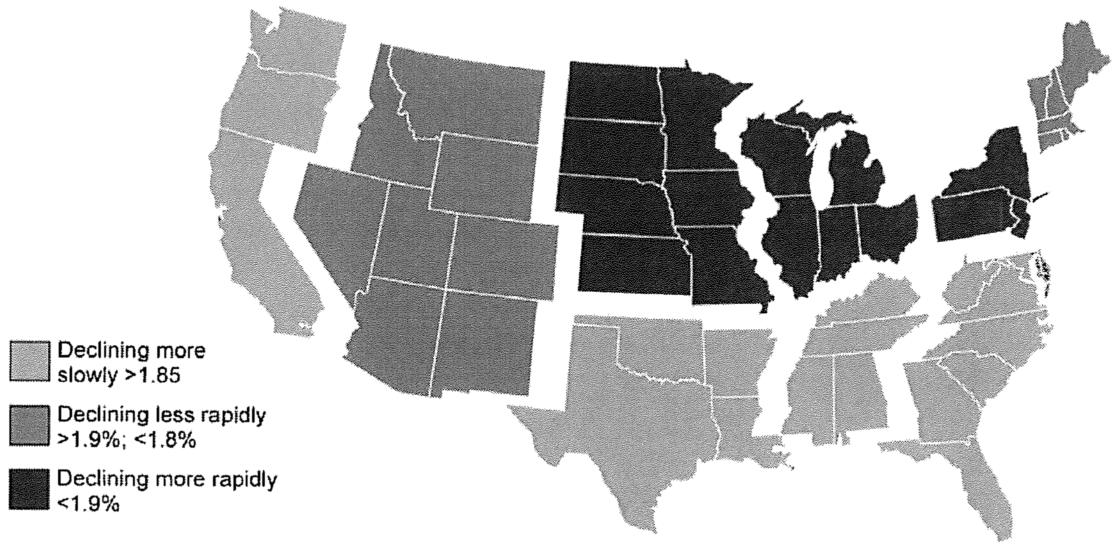


Figure 4.3: Regional Trends in Average Expenditures on Residential Electricity, 1977–2004

We now look at average expenditures on residential electricity as a share of personal income (see Figure 4.4). Although the spread of the numbers is small, there are a few interesting findings to note. First, even though expenditures on electricity have been rising, the share of electricity as a percentage of income has been declining, meaning that incomes are growing faster than electricity use. In the Mountain and Northeast regions, the relationship is what we would expect—where expenditures per dollar of income are declining rapidly, electricity intensity is growing quickly. We would expect that where the expenditures per dollar of income are declining more slowly than in other regions, electricity intensity growth would be slower or declining (as is the case in the Pacific Coast). But in the South Atlantic and East South Central regions, we find that even though the expenditure per dollar of income is not declining as fast as that in other regions, electricity intensity is growing more rapidly than in the other regions. This finding might be an indication that electricity use in the South Atlantic and East South Central regions is relatively insensitive to the cost of using electricity. At the very least, it is another indication of regional diversity. We also see some commonality among neighboring regions--for example, energy intensity in all the Southern regions is declining more slowly than in other regions, while in the mid-Northern regions it is declining more rapidly.



RAND TR292-4.4

Figure 4.4: Regional Trends in Average Expenditures on Residential Electricity as a Share of Income, 1977–2004

One might conclude from Figures 4.2 through 4.4 that there are regional differences in the relationship between electricity demand and price and regional differences in the trends in electricity usage and expenditures. Using the method described in Chapter Two, we estimated the short-run and long-run price elasticities by region, which are presented in Figures 4.5 and 4.6. We find that the regional estimates of short-run elasticities range from -.04 in the East North Central region to .31 in the South Atlantic region. We also present the 95 percent confidence interval for each of the regional estimates. Where the confidence intervals do not overlap, we can say the regions are significantly different from each other. Where they do overlap, there may be differences, but, statistically, it is difficult for us to determine if they are actually distinct. In this case, all the confidence intervals overlap to some extent, except for those for the South Atlantic and East North Central estimates. Those two regions are the only ones that have significant differences in elasticities.

Long-run demand (see Figure 4.6) is more elastic than short-run demand in each region, and while the long-run pattern is relatively similar to the short-run pattern, the East South Central region in this case is the most elastic, and the differences between the East South

Central and South Atlantic regions and the East North Central region are statistically significant. The other regions differ from one another less for long-run elasticities than they do for short-run elasticities.

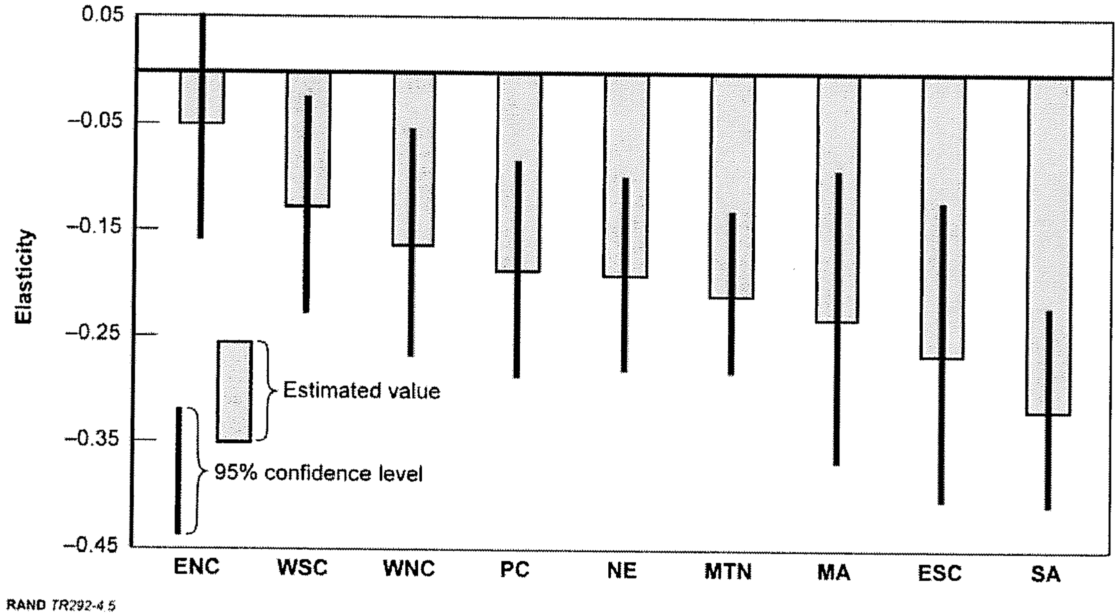


Figure 4.5: Estimated Short-Run Residential-Electricity Price Elasticities by Region, 1977–2004

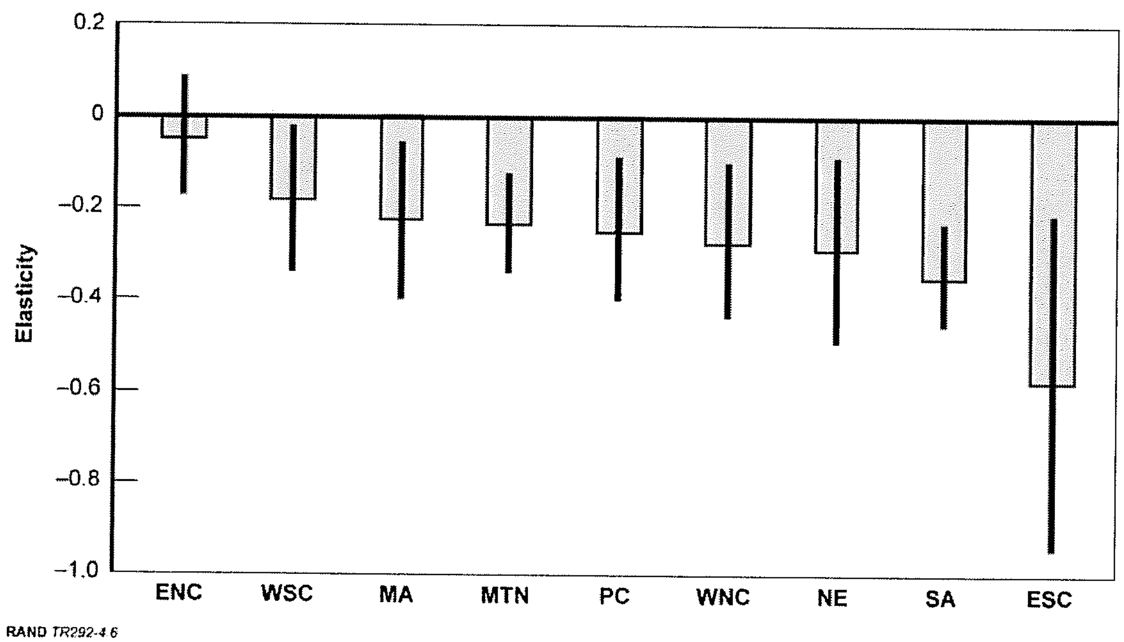


Figure 4.6: Estimated Long-Run Residential-Electricity Price Elasticities by Region, 1977–2004

When the various pieces of this analysis are brought together, they indicate that the relationship between demand and price vary enough by region that estimates of future residential electricity use or estimates of the impacts of energy-efficiency programs should reflect some of the regional variation.

Commercial Electricity Results

While the analysis of the residential electricity sector showed significant regional differences, the commercial electricity sector is somewhat less diverse. Our analysis of commercial energy intensity found some differences across regions, but the elasticities did not differ. The trend in electricity intensity per square foot of office space has been moving toward increased intensity, with slower increasing rates in the Pacific Coast and East South Central regions (see Figure 4.7). We cannot say that the Pacific Coast region is statistically different from zero in terms of commercial electricity intensity, and the West Southern Central and East Southern Central regions are significantly lower than most of the other regions. This finding indicates that new newly constructed buildings may be more energy efficient in some regions than in other regions. It may also indicate that the impacts of future improvements in commercial electricity efficiency may be larger regions with high growth in energy use, such as New England, the West North Central, and the South Atlantic, and might have little additional impact on the Pacific Coast region.

The short-run price elasticities for commercial electricity range from just under -.3 to -.15 (see Figure 4.8). Figure 4.8 indicates that some differences exist in short-run price elasticity estimates across regions, but they are smaller than the differences in such estimates across regions in the residential electricity sector. In addition, the commercial electricity estimates have considerably greater variance (larger confidence intervals) than the residential sector estimates. Given this large variance, there are no significant differences among regions. Although we cannot say the regions are statistically different from each other, it does appear that the Pacific Coast and East South Central regions are somewhat more elastic in terms of commercial electricity than the other regions, and one might look at these two regions somewhat differently than the others.

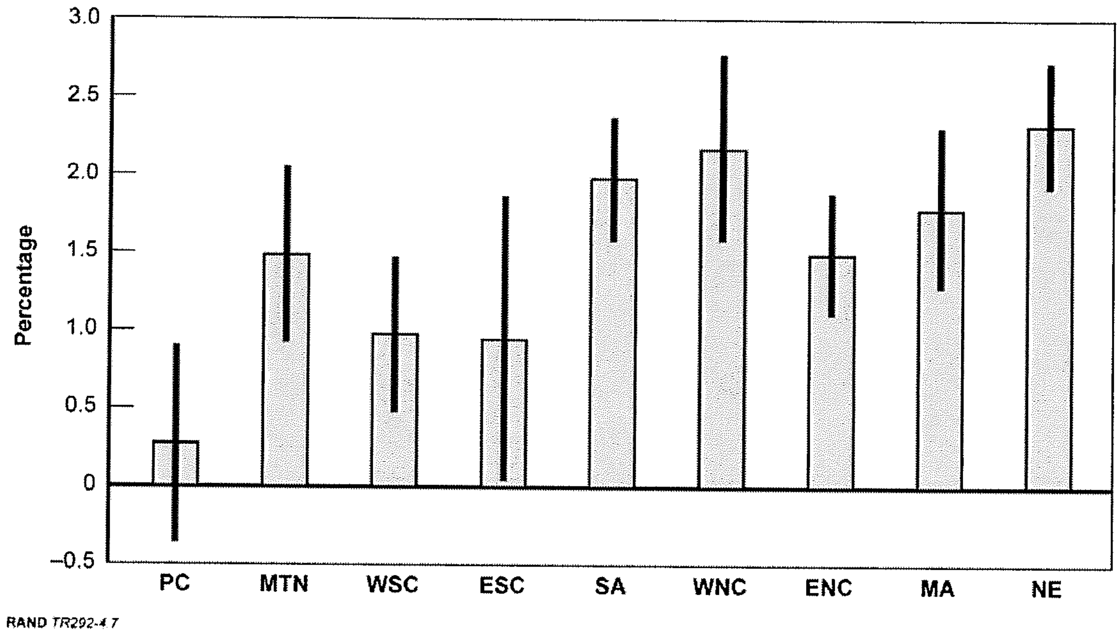


Figure 4.7: Regional Trends in Commercial Electricity Use per Square Foot of Office Space, 1977–1999

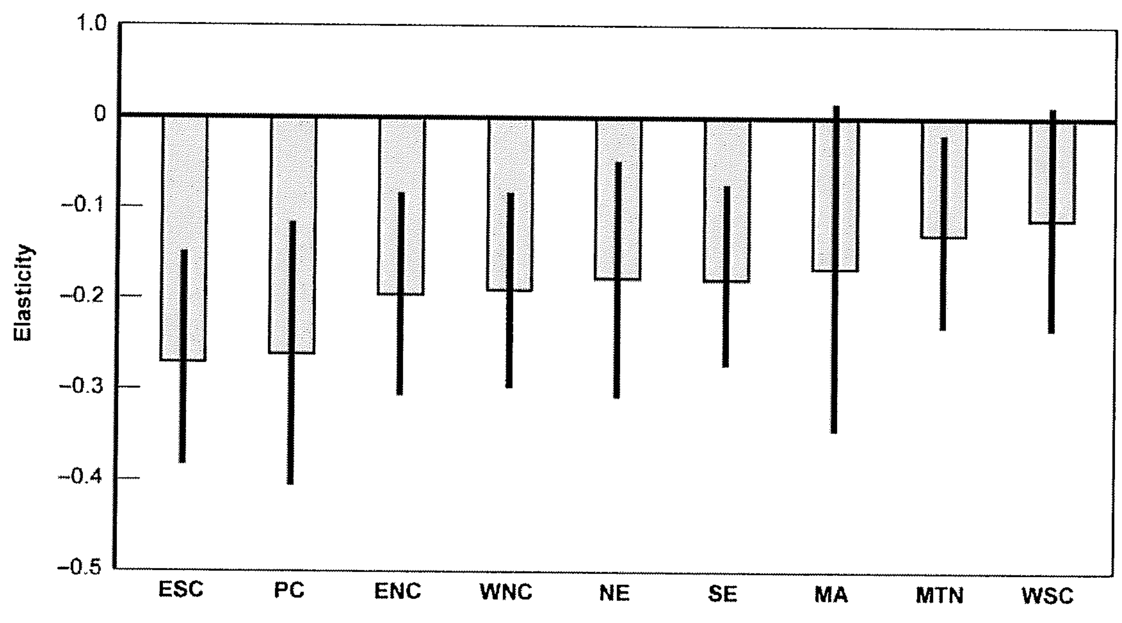


Figure 4.8: Short-Run Commercial Electricity Price Elasticities by Region, 1977–1999

Figure 4.9 shows that demand is more elastic in the long run than in the short run for the commercial electricity sector, but there is even less variation among the regions. The estimates shown in Figure 4.9 have large variances, and discerning differences in elasticities among the regions is not possible.

What we can conclude from the above discussion is that there are not many regional differences in commercial electricity use. Therefore, estimates of future electricity use at the regional level will not be greatly impacted by dissaggregation to the regional level, except perhaps for the Pacific Coast and East South Central estimates. Differences in elasticities among states are still possible, and those differences are assessed in Chapter Five.

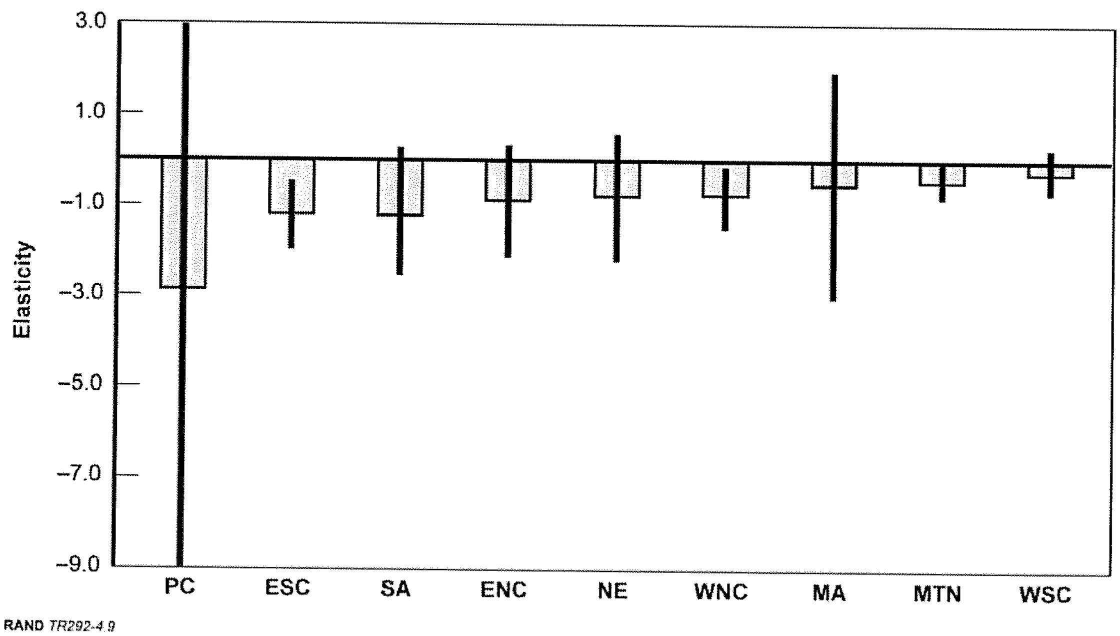


Figure 4.9: Long-Run Commercial Electricity Price Elasticities by Region, 1977–1999

Residential Natural Gas

Our analysis of residential natural-gas energy intensity and expenditures on natural gas as a share of income shows that there are differences in long-term trends among regions, although the trends themselves are small in magnitude. Figures 4.10 and 4.11 show intensity and price trends by region for natural gas. The largest increase in intensity is in the Pacific Coast, driven by Washington and Oregon, and the greatest decline in intensity is in the West South Central region, driven by Texas. There are large variations in the estimates; therefore, for the most part, we cannot distinguish among trends in intensity in the regions. Clearly, though, the Pacific Coast and Mid-Atlantic trends are positive, and the rest are negative (with the New England trend being indistinguishable from zero). This finding does suggest, however, that improvements in the efficiency of natural-gas-using appliances might have a bigger impact in the Pacific Coast and Middle Atlantic regions than they would in most other regions, and that additional improvements in the energy efficiency of natural-gas-using appliances in the West South Central region may have little impact.

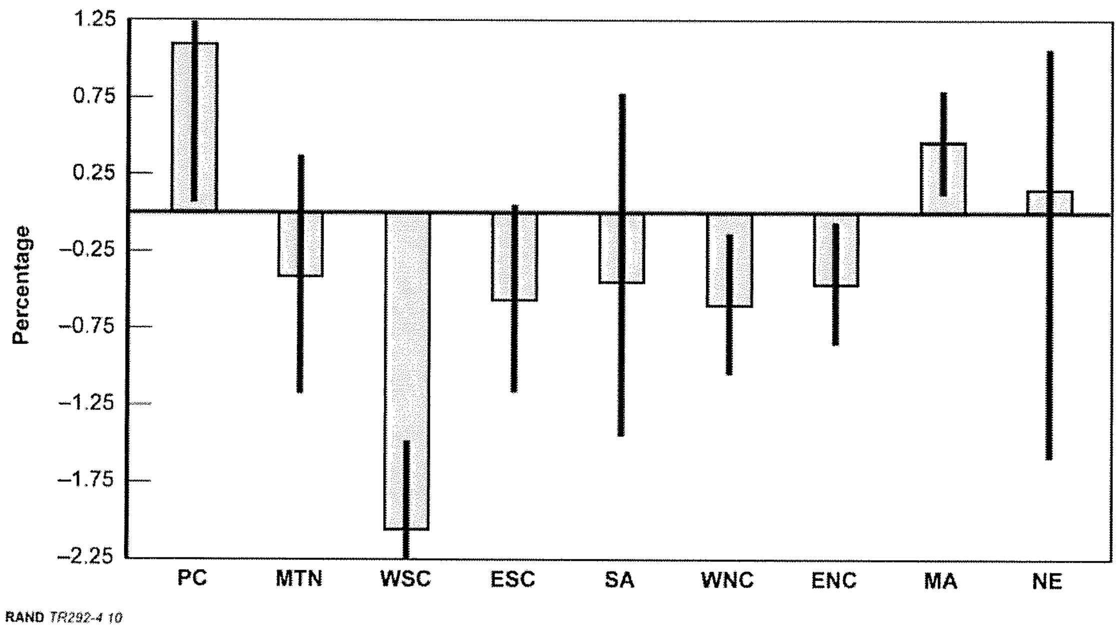


Figure 4.10: Natural-Gas Intensity Trends by Region, 1977–2004

The price trends for natural gas provide an interesting picture of the demand-price relationships one would expect. Increasing-price trends occurred in the regions with declining natural-gas intensity; the Pacific Coast and New England regions, which had increases in intensity, had an overall trend of prices not increasing (prices fluctuated across the sample for all the regions, but in the Pacific Coast and New England regions, the overall average trend was indistinguishable from zero). The sole exception to these trends is the Middle Atlantic region, which had small increasing price trends and increasing intensities. In Washington and Oregon, which were the primary drivers on the Pacific Coast for the increasing intensity, there has been some substitution of natural gas for electricity for heating purposes, some of which may have been driven by building codes that encouraged shifts from electricity for water heating. These results certainly indicate that some interesting results should be expected from the elasticity estimates.

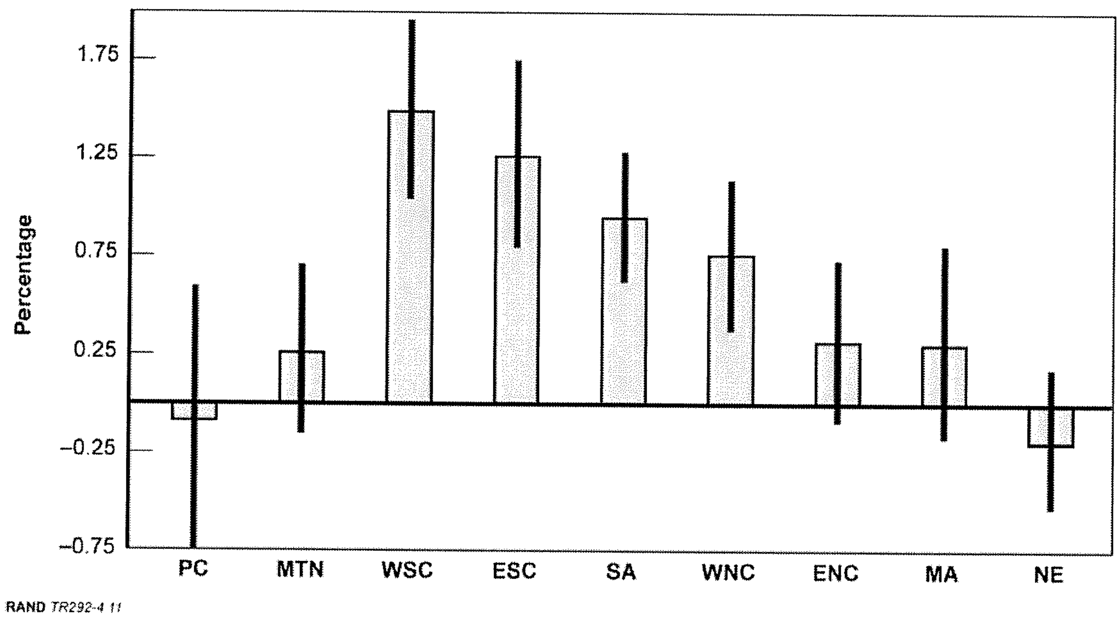


Figure 4.11: Natural-Gas Price Trends by Region, 1977–2004

Short-run price elasticity for residential natural gas varies from –0.03 for the West South Central region to –0.18 for the Pacific Coast (see Figure 4.12). The variance in the estimates, as in the commercial sector, is large. The Pacific Coast, again, has the greatest elasticity, and its neighboring Mountain region runs a close second. While we cannot say that the elasticity in these two regions is significantly different from that of the other regions, it may be worth further exploring benefits estimates for these two regions. Of the contiguous regions, the southern-state regions are the least elastic, and the northern-state regions are in the middle.

The long-run price-elasticity estimates (see Figure 4.13) are more elastic than the short-term estimates, with the most inelastic region still the West South Central and the most elastic still the Pacific Coast. While the variances are large in the long run, too, the Pacific Coast and Mountain regions are close to being significantly different from the West South Central, and there is a group in the middle with similar elasticities.

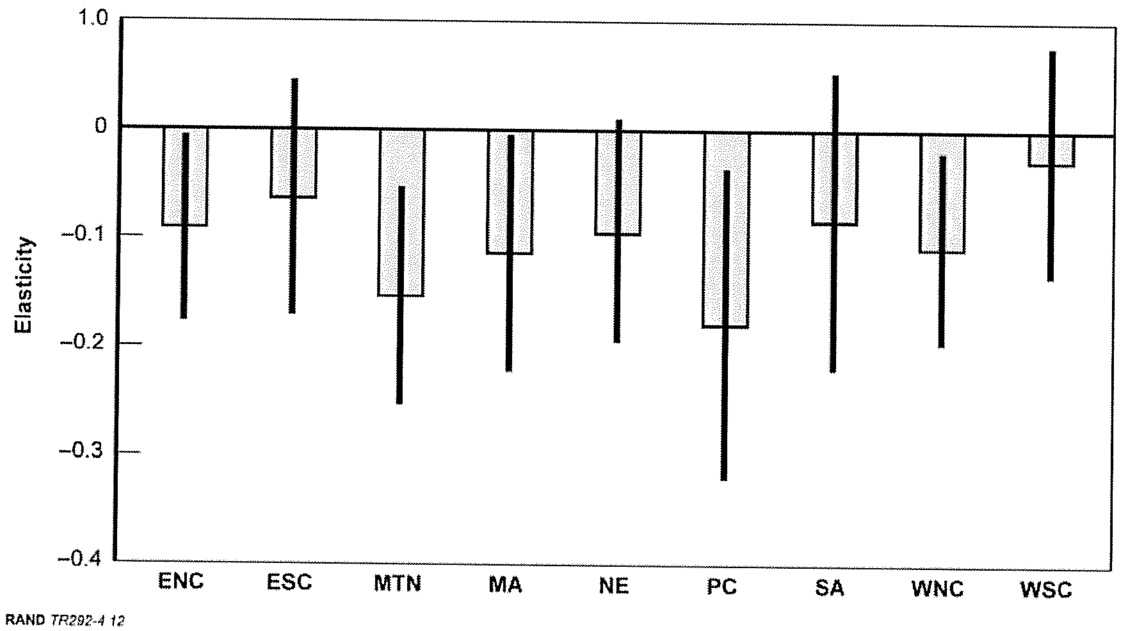


Figure 4.12: Short-Run Natural-Gas Price Elasticities by Region, 1977–2004

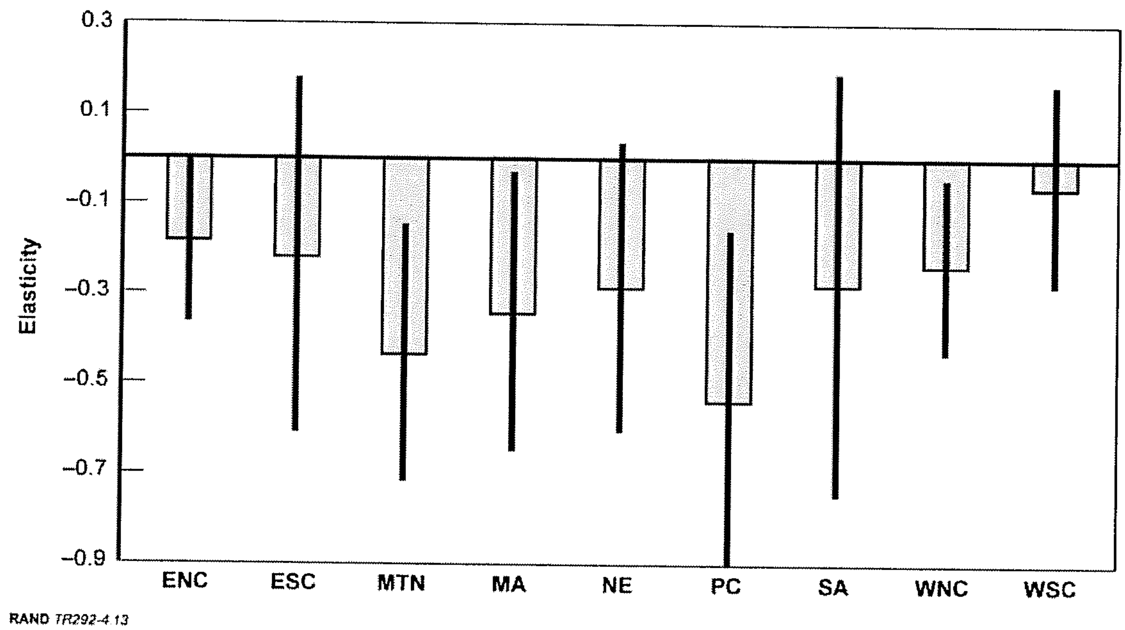


Figure 4.13: Long-Run Natural Gas Price Elasticities by Region, 1977–2004

The results for residential natural gas fall somewhere in between those for residential electricity and those for commercial electricity in terms of regional differences. As was the case with commercial electricity, there are few discernable differences in trends among the regions, but there are more differences in the elasticities than in commercial electricity, although still not at the level of significance that was seen in residential electricity. It might make a difference in forecasts and estimates if the Pacific Coast and Mountain regions are differentiated from the other regions.

Regional Analysis Conclusions

The analysis of regional-level differences in the price-demand relationship provides different answers for different markets. It seems clear that there are regional differences in the residential electricity market, and that estimates of the impact of energy efficiency and forecasts of electricity demand could differ significantly if the regional differences are taken into account. Clearly, commercial electricity does not appear to differ significantly by region; therefore, national-level estimates of commercial electricity price-demand relationships are likely to be sufficient for analyzing the impact of energy efficiency in the commercial sector. The picture for residential natural gas is somewhat different. There is not a lot of variability in energy-use trends over time, which is probably why there is not much difference by region in the price-demand relationship. It appears that demand responds more to price in two of the regions than in the others, and this finding could have some implications for estimates of the benefits of energy efficiency, but national level results in this case are probably also sufficient for analyzing the impact of energy efficiency in the commercial sector

Chapter 5: State-Level Analysis

In this chapter, we use a methodology similar to the one that was used for the analysis in the previous chapter, but in this case, we differentiate state-level elasticities and trends. The state-level analysis consists of an examination of trends and an estimation of short-run and long-run price elasticities for each state.

Residential Electricity

Beginning again with residential electricity, we look at the key trends in energy intensity and expenditures as a share of income. In terms of electricity use per capita (see Figure 5.1), there are only a few states, which are concentrated in the West and New England, with trends of small or declining energy intensity over the period studied. As we found in the regional-level analysis, the high-growth areas in terms of residential electricity usage are concentrated in the South. The significance of Figure 5.1 is in the consistency it shows within regions. While the energy intensity trends do vary within each region, they do not vary significantly. There are no regions with some states with declining intensity and some states with rapidly increasing intensity. This is a first indication that the regional-scale analysis might be sufficient for analyzing the impacts of energy efficiency.

We do observe some inter-regional variation in electricity expenditures as a share of income (see Figure 5.2). There is some diversity within each of the regions, although in most cases, the differences among states in a region are small except for a single state. Because the demand is consistent within regions, but the expenditures and prices are not, the elasticities in states in each region might vary.

Next, we take a look at the differences in estimated residential electricity price elasticities, which are illustrated in Figure 5.3. Each square-shaped plot point in the figure represents a U.S. state, and the vertical lines represent the 95 percent confidence interval. Sixteen states have an estimated elasticity that is positive over the period studied, although the variance is large enough in most cases that it is difficult to distinguish it from zero. There are a few possible explanations for this observation. In the early years that were studied, when prices were rising, these states saw consistent increases in demand, and in the later time period, when prices were declining in real terms, these states did not have rapid growth in demand. Therefore, overall, it would appear that the demand-price relationship reacts differently in these states than in other states. We caution, however, that it is possible that in the future, increases in prices in these states would not lead to increases in demand, but that the demand in these states would indeed slow or decrease in a manner similar to that in other states (although the elasticity might still be substantially less than that in other states).

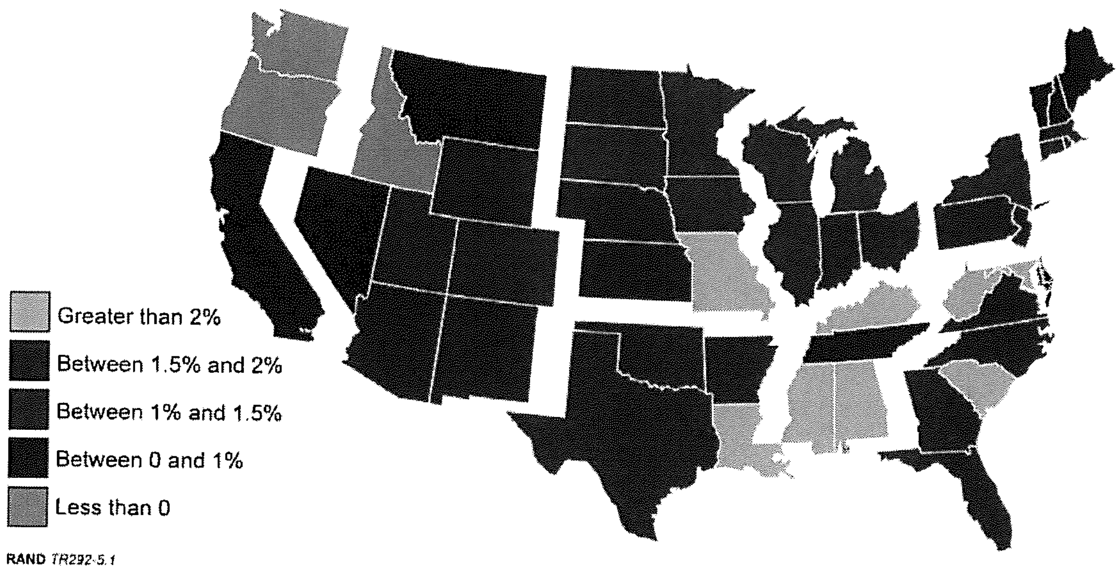


Figure 5.1: State-Level Trends in Residential Electricity Intensity, 1977–2004

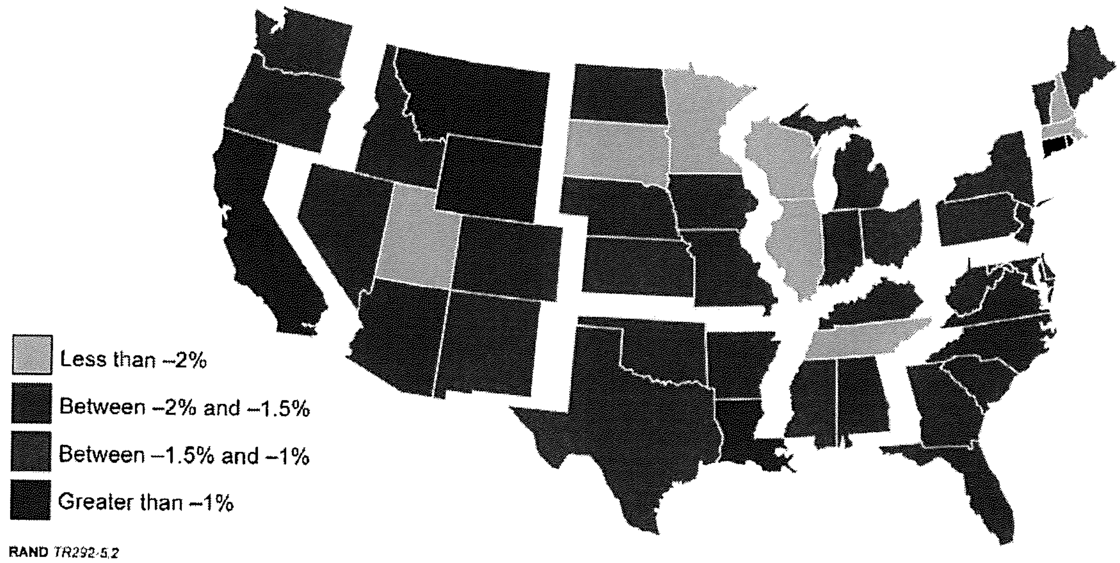


Figure 5.2: State-Level Trends in Residential Electricity Expenditures as a Share of Income, 1977–2004

One other finding of note, illustrated in Figure 5.3, is that there are ten states (represented by the squares on the right-hand side of the figure with positive elasticities) that are significantly different than 11 states represented by the squares on the left-hand side of the figure (all of which have elasticities less than –.2). Given the size of the variances, it is difficult to distinguish differences in price elasticities among the other states.

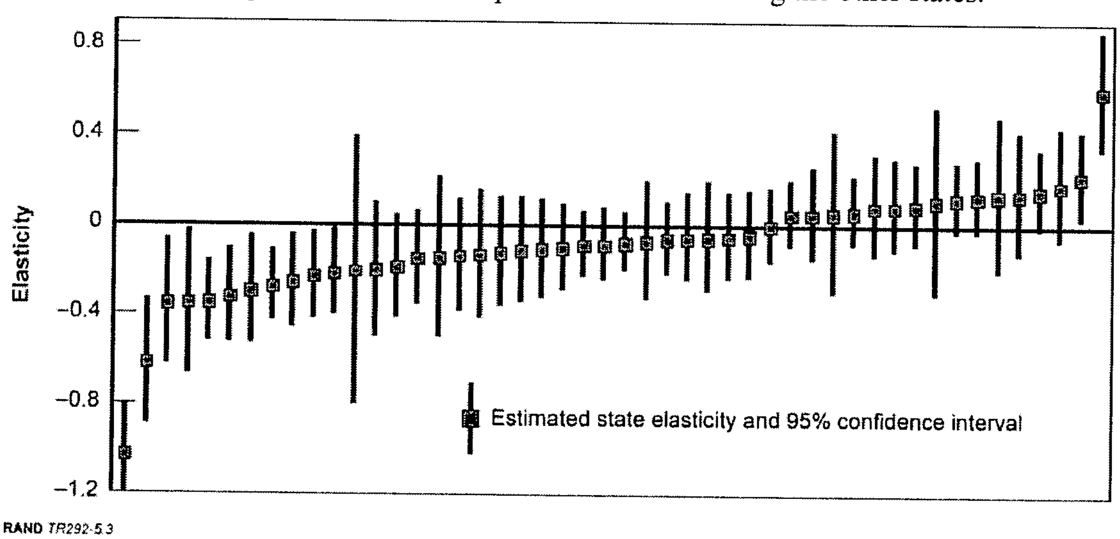


Figure 5.3: Estimates of Short-Run Residential Electricity Price Elasticities for Each State, 1977–2004

In Chapter Four, we illustrated significant differences in elasticities among regions. When we look at the individual state elasticities, some consistencies within the regions emerge. Figure 5.4 shows that several Mountain, West South Central, and West North Central states appear to have similar lower-positive or higher-positive price elasticities for residential electricity. Nevada, Idaho, Utah, Wyoming, Colorado, New Mexico, Oklahoma, Kansas, and Nebraska form a block of states with very inelastic demand (or estimated positive elasticities); the price-demand relationship in these states appears to be somewhat similar. Another broad region with notable results falls in the middle of the country and the Southeast. The group of states from Missouri to Florida has larger-than-average price elasticities, with the East South Central and South Atlantic regions showing some inter-regional inconsistencies. States within the Middle Atlantic region are consistent in terms of elasticities, as are the states in the East North Central region (with the exception of Wisconsin). This finding implies that even though there are considerable differences among the states in price elasticities, there are some regional consistencies. Therefore, disaggregation of data by region might still be sufficient for energy-efficiency impact analyses.

As one might expect, the geographic patterns in long-run price elasticity estimates (see Figure 5.5) are similar to those in the short-run price elasticity estimates. The Mountain states have inelastic demand, whereas states in the South Atlantic and East South Central, Pacific Coast, and New England region have more-elastic demand in the long run. The variance in the long-run elasticity estimates is larger than in the short-run estimates, and more states exhibit positive long-run price elasticities than positive short-run price elasticities. Overall, these findings seem to indicate that over the time period studied, electricity demand continued to rise in many of these states, regardless of price. Given the prices and demand that were observed over this time period, it is not clear whether any conclusions can be made about how long-run demand would react to price increases. We can say, again, that there appear to be regional differences, but consistencies among states within the regions, in the long-run price-demand relationship.

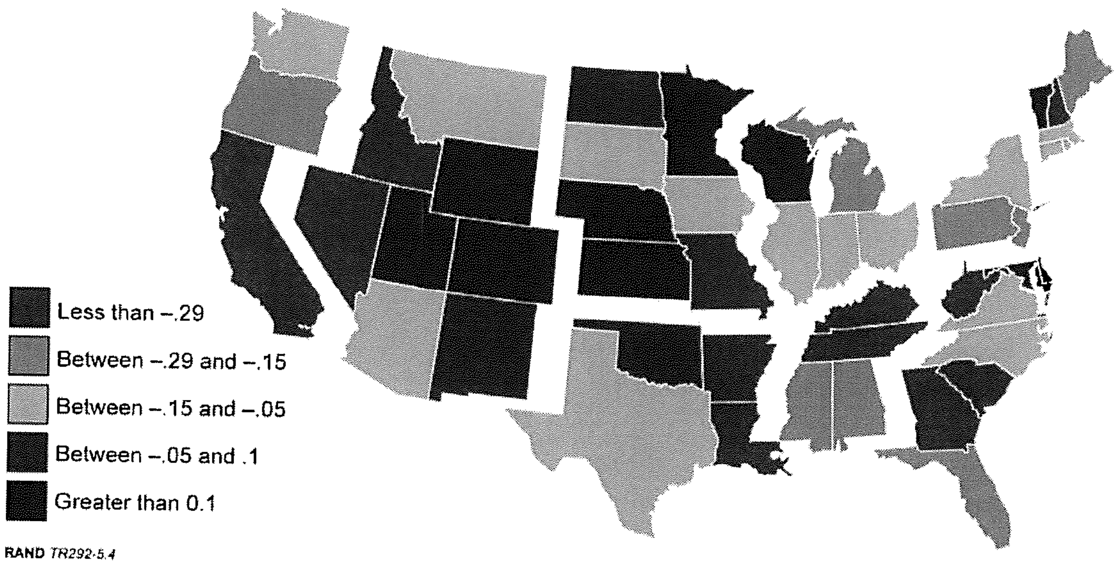


Figure 5.4: Estimated State-Level Short-Run Price Elasticities for Residential Electricity, 1977–2004

Overall, the findings presented in this section imply that while regional disaggregation will be important for estimating future impacts of energy-efficiency technology and forecasting demand for residential electricity, state-level disaggregation may not be necessary for that purpose.

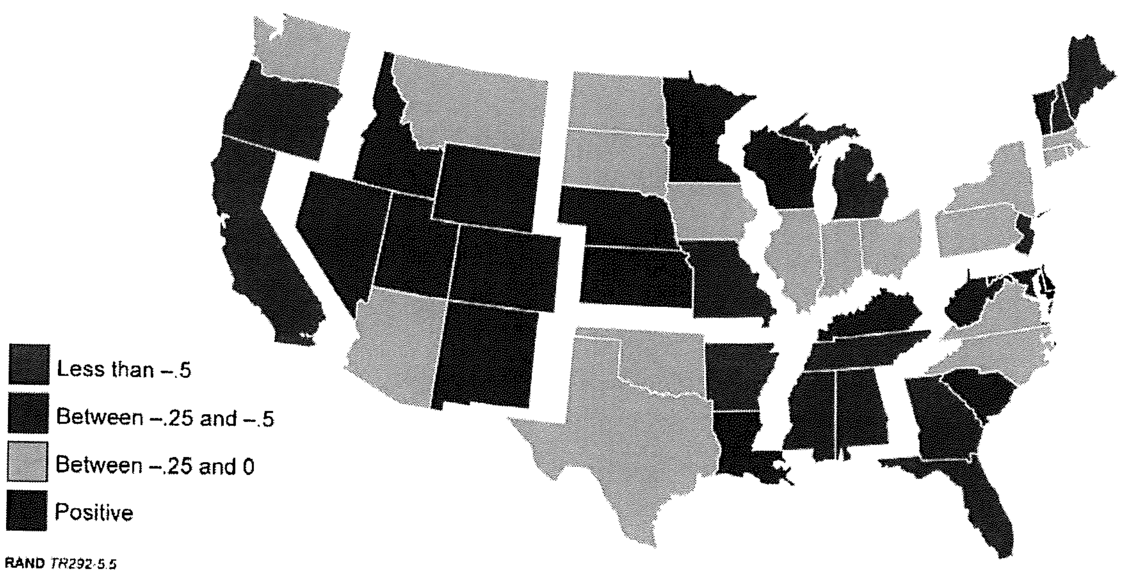


Figure 5.5: Estimated State-Level Long-Run Price Elasticities for Residential Electricity, 1977–2004

Commercial Electricity

The state-level analysis of the commercial electricity sector reveals a pattern of electricity usage similar to that at the regional level – there seems to be some state-level variation in electricity use patterns, but few differences in the price-demand relationship. Figure 5.6 shows trends in commercial electricity use per square foot of office space (i.e., the trends in intensity). We see the slowest growth in electricity use in states in the West, although a few of those states show a slow growth in intensity. There is some consistency in intensity among states within regions. For the most part, states within a region fall into one of two consecutive categories of growth. Again, this finding seems to indicate that the regional analysis would be sufficient to capture any differences that might exist in electricity intensity in the commercial sector.

The estimated elasticities in commercial-sector intensity are what we might expect from the previous sets of analysis. Figure 5.7 shows the estimated state-level short-run elasticities. There is not much variation across the states in intensity, except for a few that are represented at the left side of the figure. For the most part, the estimated elasticities range between –.5 and zero, with a few states with positive elasticity (that is not significantly different from zero), and a few states that seem to have more-elastic demand. It is interesting to note that for a large number of states, the variance is small, which means that the elasticities are well estimated. This is in contrast to the residential sector, in which the variance is large for a number of states. There is also more variation among the states in the residential-sector analysis in comparison with the commercial-sector analysis, which shows little variation among the states. We observed the same sort of patterns for the long-run elasticities.

Clearly, there does not seem to be a reason to disaggregate the analysis for commercial electricity to the state level.

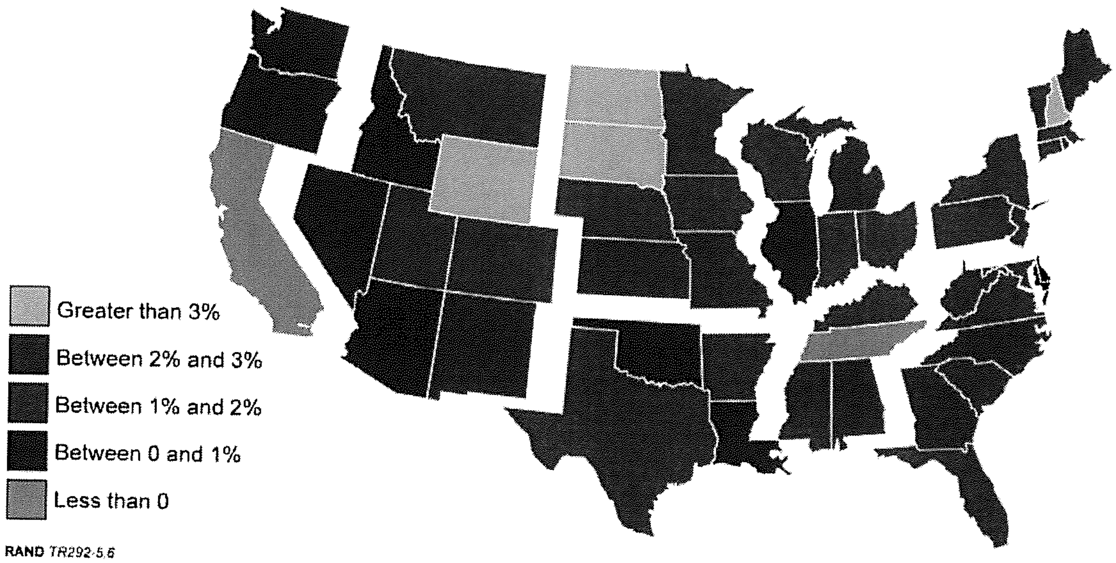


Figure 5.6: Estimated State-Level Trends in Electricity Intensity in the Commercial Sector, 1977–1999

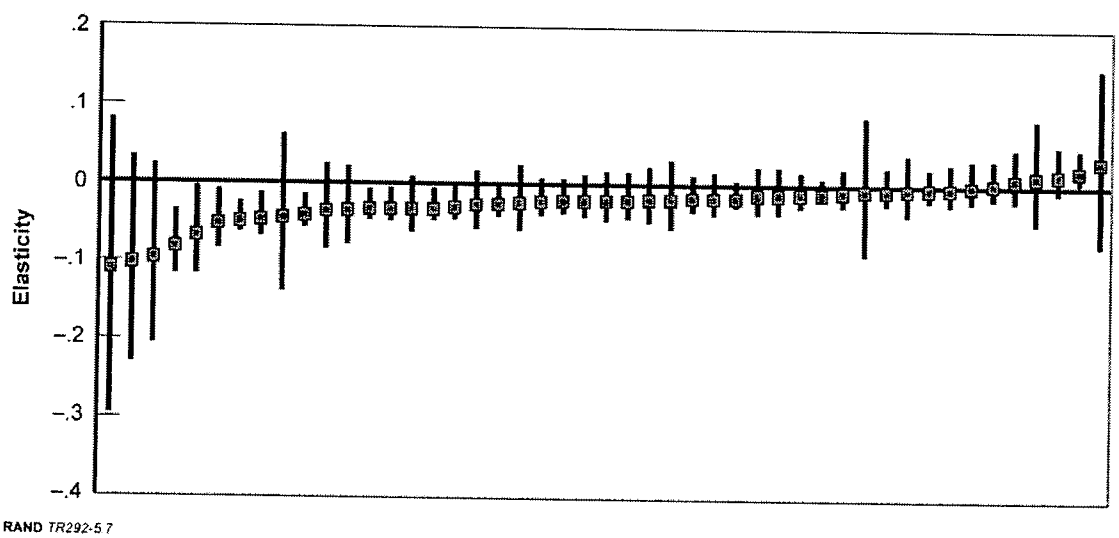


Figure 5.7: Estimated Short Run Elasticities in Electricity Intensity in the Commercial Sector at the State Level, 1977–1999

Residential Natural Gas

Because the regional-level results for residential natural gas showed little regional diversity and a lot of variance in the estimates, it is not surprising that we find basically the same results at the state level. There are differences among states, which become evident when looking at natural-gas intensity at the state level (see Figure 5.8). What is also evident is that there is significant variation among states within regions, with the notable exception of the East North Central and the West South Central, where the trends in natural gas use per capita are fairly consistent. Otherwise, there is not much in the way of observed patterns to note. There are more states in the North that have growing natural-gas intensities, but a group of states in the South Atlantic (and Tennessee) also have growing intensities.

Given these findings, it is not surprising that we also find some large differences among the states in estimated short-run price elasticities for natural gas (see Figures 5.9a and 5.9b) along with very large variances among the states. The price elasticities range from -.3 to .1, which is quite a broad range, but the variances are so large that we cannot even say that states at the extreme low end of the range are statistically different from other states. Reflecting what we observed at the regional level, there is not much in the way of consistency among states within the regions in terms of price elasticity. There is a group of contiguous states ranging from the middle of the country to the East Coast that have some similarities in elasticities. But again, because the variances are so large, there is not much we can interpret from these results, and there does not seem to be much of a reason to assess natural-gas demand and the benefits of energy-efficiency technologies at the state level.

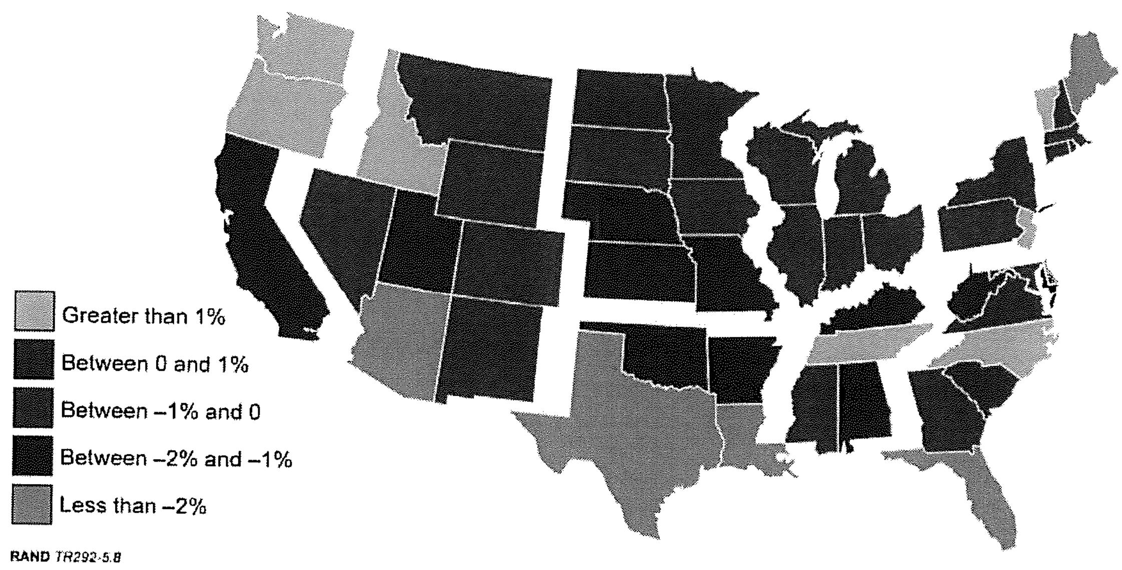


Figure 5.8: Trends in Natural-Gas Intensity at the State Level, 1977–2004

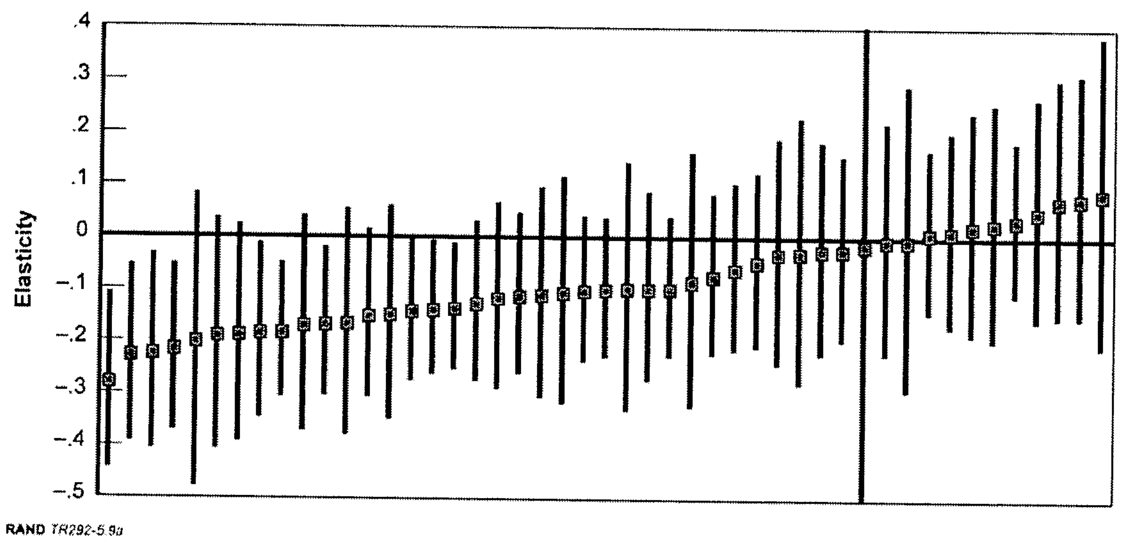


Figure 5.9a: Estimated Short-Run Price Elasticities for Natural Gas at the State Level, 1977–2004

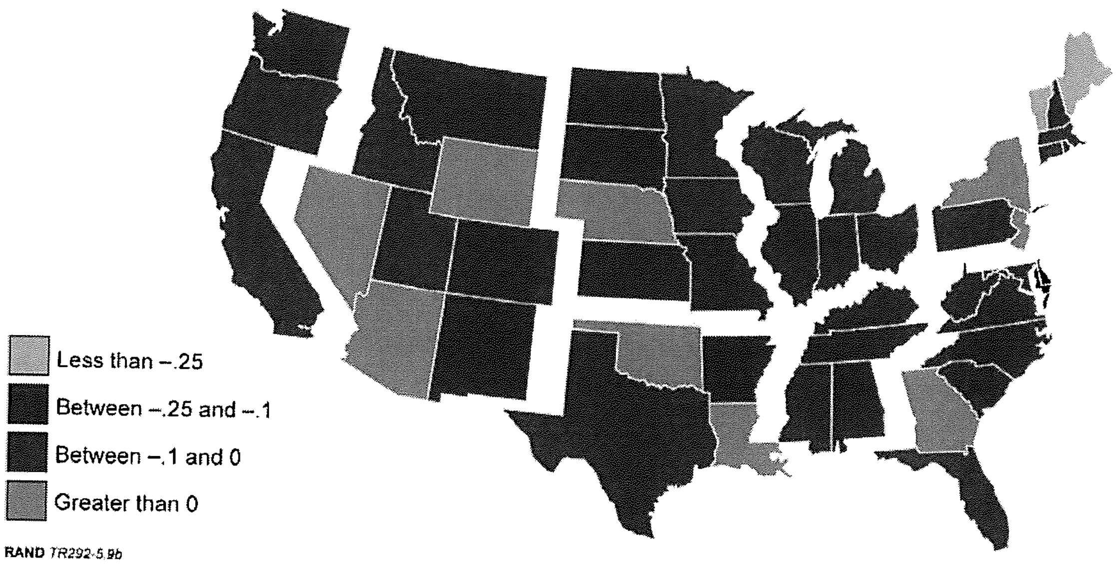


Figure 5.9b: Short-run Price Elasticities for Natural Gas

State-Level Conclusions

There are differences among the states in price elasticities and in some trends in energy use and other factors, but, for the most part, they are not significant. As was seen with the regional analysis, there is a difference between the results of the residential electricity analysis and those of commercial electricity and residential natural-gas analyses. For residential electricity use, there is enough consistency among states within regions that a state-level disaggregation would not likely produce different results than would regional-level analyses for forecasting the estimated benefits of energy-efficient technologies.

For commercial electricity and residential natural gas, there is not much consistency among states, and there are significant amounts of variance in the estimates; therefore, it is not certain that one could use our approach to differentiate states to a degree that would be useful in forecasting estimates of energy-efficiency benefits.

Chapter 6: Utility-Level Analysis

The utility-level analysis posed a number of analytical challenges, which limited the conclusions that we were able to draw from our analysis. While consumption and price data at the utility level were available in the database that we used, data on other factors that are key to the price-demand analysis (such as income and climate) were not. As such, we used state-level data in place of the unavailable utility-level data. Nevertheless, we continued with the experiment to see if there appear to be significant differences in how price and demand respond at the utility-scale level, simply to glean whatever information that might contribute to this study.

We did discover a few interesting things in this analysis. First, there is a lot of variation in elasticities among the utilities, which was not unexpected, although the price elasticities for about 65 percent of the sample are not statistically significant. Figure 6.1 illustrates the percentage of the sample of utilities that are in each region (shown in Figure 4.1), and of those, the percentage with estimated price elasticities that are statistically significant. There are no apparent regional consistencies, other than the South Atlantic and East North Central regions having the highest percentage of utilities with significant elasticities. For most regions, the percentage of utilities in the region and the percentage with significant estimates are very similar. At one end, the East North Central region had about 5 percent more utilities with statistically significant price elasticities, as a proportion of all utilities in the dataset, than the region's percent of the total number of utilities in the data set, and the Mountain region had more than 5 percent fewer utilities with statistically significant price elasticities.

The price-elasticity estimates are wide-ranging and have limited precision. The range of elasticities for the statistically significant estimates was 1.1 to –1.87. The median was –0.57, and the mean was –0.63.

Size of a utility appears to be correlated with the elasticity estimate. The range of elasticity estimates for the largest utilities (the median is –0.25, and the mean is –0.29) is similar to the range of estimates found in the state analysis. There is greater variability in the elasticity estimates observed in the small utilities, which results in a larger range of estimates.

Overall, we cannot conclude much from the utility-level analysis, other than the large amount of variation in price elasticities suggests that it may be useful to delve further into analyzing utility-level electricity demand. Further analysis may produce information that is valuable for planning and estimating energy efficiency at this level.

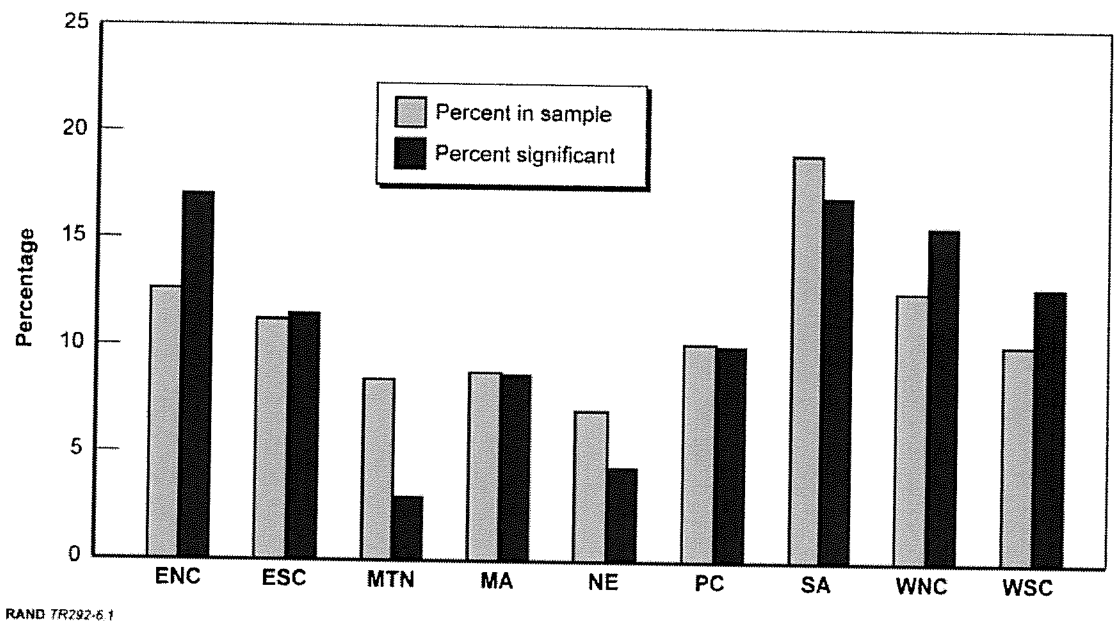


Figure 6.1: Percentage of Utilities in the Sample within Each Region and Percentage in Each Region with Significant Elasticities

Chapter 7: Conclusions, Final Thoughts, and Implications of Analysis

This chapter reviews the results of our analysis and their implications and presents our recommendations for further analysis. The key findings from this study are as follows:

- There are state and regional differences in (1) electricity and natural-gas demand, (2) the relationship between changes in demand and changes in price (i.e., elasticity), and (3) factors that influence demand.
- It is difficult, with the data we have available, to show statistically significant differences at all levels for commercial electricity and residential natural gas, though our results do indicate there may be regional and state differences in how price and demand interact in each of those sectors.
- We found significant regional differences in the price-demand relationship for residential electricity, but also found consistencies in the price-demand relationship for residential electricity among states within regions.
- The price-demand relationships have not changed over the past couple of decades—our estimates are about the same as those from studies done in the 1980s.
- Price elasticity—-i.e., how demand reacts to changes in price overall—has continued to be small since the 1980s.
- Over the periods we examined (1977–2004 for residential electricity and natural gas, 1977–1999 for commercial electricity, and 1989–1999 for residential electricity at the utility level), some basic trends emerged: Demand for energy overall is increasing; in many cases, energy intensity is increasing, but price is decreasing; and, while expenditures on energy are increasing, energy expenditures as a share of consumers' income and as a share of commercial sector output are declining.
- The past few years have seen some changes in these patterns, and it is possible that some of these trends and relationships might exhibit further changes.

Should DOE Disaggregate Data for Estimating Energy-Efficiency Programs Benefits?

The results of this study have a number of implications for the DOE's decisionmaking and policymaking. The basic question that was the impetus for this analysis was whether the DOE should disaggregate data (from the national level to the regional, state, or utility level) when estimating the benefits of its energy-efficiency programs. The answer to this question has a number of components.

We first made the case that certain factors might affect the impact that energy efficiency would have on overall demand. We also made the case that the price-demand relationship, or price elasticity, was important for estimating the impact of energy-efficiency programs and technology. In examining demand in each sector (residential and commercial electricity demand and residential natural-gas demand), we found that there are some differences in regional trends—in particular, trends in the intensity of energy use. Energy efficiency might have a bigger impact on regions with rapidly growing intensity of use than on regions with intensity that is either declining or growing slowly.

In terms of the price-demand relationship, if increasing prices motivate investments in energy efficiency, then the impact of energy efficiency might be greater in regions or states that are the most elastic (i.e., those with the lowest negative price elasticities). In these regions and states, the price-demand relationship is the most robust, and changes in price could lead to greater changes in energy efficiency, and vice-versa. Any estimates of the impact of energy-efficiency programs will be impacted by price elasticity, and if the elasticity differs significantly by region or state, the estimates of the impacts will differ accordingly.

In the case of the residential electricity sector, it is clear that there are regional differences. It also seems clear that the elasticities are relatively consistent among states within the regions and that, at least for the near term, disaggregating data on energy-efficiency programs to the regional level should be sufficient to evaluate the different effects that energy efficiency could have in different regions of the country.

The results are less clear for the commercial electricity sector. Few regions appear to have significantly different trends in the intensity of electricity use (specifically the Pacific Coast and perhaps the West North Central and East South Central regions, which have had slower growth). Statistically, it is difficult to distinguish among the other regions in terms of intensity of use, and there are no discernable differences in the price elasticities between regions. It does seem that the impact of energy efficiency in the Pacific Coast would differ from the impact in the rest of the country, and perhaps disaggregating Pacific Coast data from the national-level data is all that is needed to estimate the impact of certain DOE programs. On the other hand, there is some consistency in price elasticities among states within regions, such as what was seen in the residential electricity sector, although not to as great an extent. This finding does suggest that a state-level analysis would not be necessary in the short term.

The results are even less clear for the residential natural-gas sector. As in the commercial sector, only a couple of regions (again, the Pacific Coast and the West South Central region) seem to differ from the rest in all the factors we examined. But there is little consistency in the states within the DOE regions and little statistical difference among the estimated elasticities for each region. If one uses the estimated elasticities, the impact of energy-efficiency programs in the Pacific Coast and in the West South Central region would differ if one were to compare the two regions. This makes interpreting the findings on residential natural gas use more difficult than interpreting the findings for the other energy sectors. One finding of note is that the changes in demand for natural gas are smaller than those for electricity over the time period studied, so perhaps national-level analysis would be sufficient for determining the impact of energy-efficiency programs on demand in the residential natural-gas market.

Price Elasticity of Demand

The results on price elasticity are interesting. Our elasticity estimates are no different from those from ten to 20 years ago. This indicates that the relationship between price and demand has not changed even though (1) 15 to 20 additional years of empirical data are available; (2) there have been changes and shifts in energy use, in particular the introduction of new electricity-using devices; (3) there have been large increases in air-conditioning loads; and (4) appliances are more energy efficient than they were 15 to 20 years ago.

In addition, the elasticities remained the same over the past two decades—i.e., they remained low. In other words, demand did not tend to react much to changes in price. There are small, and somewhat consistent, changes, but on the surface it seems that there are few options for consumers or commercial businesses to switch to electricity or natural gas use in response to energy prices.

These observations, however, might be driven more by the trends in factors affecting intensity than by how consumers react to changes in price. Over the time period studied, we observed the following general trends:

- Energy prices heading downward
- Energy costs as a share of income also heading downward
- Energy use rising.

Given these trends, it is difficult to find significant variations in the price-demand relationship, because prices and demand have not varied much. Also, it is difficult to achieve improvements in energy efficiency when energy costs continue to decline, beyond those that "naturally" occur through technology improvements.

On the other hand, it is possible that the price-demand relationship is changing. First, just anecdotally, when California was facing energy problems in 2000 and 2001, a combination of factors led to a significant reduction in residential electricity use, with reductions in electricity demand estimated to be as high as 9 percent in response to government policy, media coverage, and rising prices. At least in a case such as that, consumers will change their demand behavior in the short term in response to energy prices and energy policy.

In the past few years, we have witnessed a reversal of the downward price trends and, at the same time, we have seen a reversal in the upward trend in electricity intensity in a number of states. Overall, prices have not been declining as rapidly, and energy use has not been increasing as rapidly either. So, it is possible that with an increasing-price regime, one might see a different demand-price relationship than what would be observed in a decreasing-price regime. More study and analysis would be needed to uncover these trends.

Bibliography

Bentzen, Jan, and Tom Engsted, "A Revival of the Autoregressive Distributed Lag Model in Estimating Energy Demand Relationships," *Energy*, Vol. 26, 2001, pp. 45–55.

Bernstein, Mark, Kateryna Fonkych, Sam Loeb, and David S. Loughran, *State-Level Changes in Energy Intensity and Their National Implications*, Santa Monica, Calif.: RAND, MR-1616-DOE, 2003.

Bernstein, Mark, Robert J. Lempert, David S. Loughran, and David Ortiz, *The Public Benefit of California's Investments in Energy Efficiency*, Santa Monica, Calif.: RAND, MR-1212.0-CEC, 2000.

Bohi, Douglas R. and Mary Beth Zimmerman, "An Update on Econometric Studies of Energy Demand Behavior," *Annual Review of Energy,* Vol. 9, 1984, pp. 105–154.

Dahl, Carol A., "Do Gasoline Demand Elasticities Vary?" *Land Economics*, Vol. 58, No. 3, August 1982, pp. 373–382.

Dahl, Carol A. and Thomas Sterner, "Analysing Gasoline Demand Elasticities: A Survey," *Energy Economics*, July 1991, pp. 203–210.

Dubin, Jeffrey A. and Daniel L. McFadden, "An Econometric Analysis of Residential Electric Appliance Holdings and Consumption," *Econometrica*, Vol. 52, No.2, March 1984, pp. 345–362.

Garcia-Cerutti, L. Miguel, "Estimating Elasticities of Residential Energy Demand from Panel County Data Using Dynamic Random Variables Models with Heteroskedastic and Correlated Error Terms," *Resource and Energy Economics*, Vol. 22, 2000, pp. 355–366.

Griffin, James M., and Craig T. Schulman, "Price Asymmetry in Energy Demand Module: A Proxy for Energy-Savings Technical Change," *The Energy Journal*, Vol. 26, No. 2, 2005, pp. 1–21.

Houthakker, H .S., Philip K. Verleger, Jr., and Dennis P. Sheehan, "Dynamic Demand Analyses for Gasoline and Residential Electricity," *American Journal of Agricultural Economics*, Vol. 56, No. 2, May 1974, pp. 412–418.

Hsing, Yu, "Estimation of Residential Demand for Electricity with the Cross-Sectionally Correlated and Time-wise Autoregressive Model," *Resource and Energy Economics*, Vol. 16, 1994, pp. 255–263.

Maddala, G. S, Robert P. Trost, Hongyi Li, and Frederick Joutz, "Estimation of Short-Run and Long-Run Elasticities of Energy Demand from Panel Data Using Shrinkage Estimators," *Journal of Business & Economic Statistics*, Vol. 15, No. 1, January 1997, pp. 90–101.

Mead, Walter J., Timothy D. Mount, Richard L. Gordon, and A. Myrick Freeman III, "Discussion on McDonald, Searl, Perry, Houthakker, Verleger, Jr., Sheehan, and Wilson," *American Journal of Agricultural Economics*, Vol. 56, No. 2, May 1974, pp. 427–435.

North American Electricity Reliability Council, "2005 Summer Assessment: Reliability of Bulk Electricity Supply in North America," May 2005.

O'Neill, Brian C., and Mausami Desai, "Accuracy of Past Projections of U.S. Energy Consumption," *Energy Policy*, Vol. 33, 2005, pp. 979–993.

Pesaran, M. Hashem, and Ron Smith, "Estimating Long-Run Relationships from Dynamic Heterogeneous Panels," *Journal of Econometrics*, Vol. 68, 1995, pp. 79–113.

Taylor, Lester D., "The Demand for Electricity: A Survey," *The Bell Journal of Economics*, Vol. 6, No. 1, Spring 1975, pp. 74–110.

U.S. Department of Energy, *National Transmission Grid Study,* Washington, D.C.: DOE, May 2002.

Wooldridge, Jeffrey, *Econometric Analysis of Cross Section and Panel Data*, Cambridge, Mass.: MIT Press, 2002.

Wooldridge, Jeffrey, *Introductory Econometrics: A Modern Approach*, Cincinnati, Ohio: South-Western College Publishing, 1994.

Appendix A: Details on the Methodology Used to Estimate Elasticities

The primary goal of this study is to measure how the energy-demand relationship varies at different levels of spatial aggregation (i.e., at the national, regional, state, and utility level). We model the demand relationship as a function of four components:

- measured variables that vary across states and within states over time—such as energy prices, income, population, and climate
- fixed differences between states—unmeasured variables that do not change in the study period but that differ across states
- an aggregate time trend—one that accounts for unmeasured variables common to all states, such as federal policy
- a random error term that varies across and within states.

We estimate this model with the following fixed-effects specification:

$$Q^{D}_{i,t} = Q^{D}_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

where $Q^{D}_{i,t}$ is log energy demand in state i and year t, $Q^{D}_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g., energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The residual has three components:

- s_i is an indicator variable that captures time-invariant differences in energy demand across states ("state fixed effects").
- y_t is an indicator variable that captures time effects common to all states ("year fixed effects").
- $\varepsilon_{i,t}$ is a random error term.

We based this specification on the flow-adjustment model developed by Houthakker et al. (1974). In this model, demand is a function of prices, income, population, and climate.

$$Q^{D*}_{i,t} = f(P_{i,t}, P^{C}_{i,t}, Y_{i,t}, Pop_{i,t}, Climate_{i,t})$$

where Q^{D*} denotes desired demand in time t. The model assumes the following adjustment process between periods:

$$Q^{D}_{i,t}/\, Q^{D}_{i,t-1} = (Q^{D*}_{i,t}/\, Q^{D}_{i,t-1})^{\theta}$$

where $0< \theta < 1$. The estimating equation then becomes the following:

$\ln Q^{D}_{i,t} - \ln Q^{D}_{i,t-1} = \theta \ln Q^{D*}_{i,t} - \theta \ln Q^{D}_{i,t-1}$

$\ln Q^{D}_{i,t} = \theta \ln Q^{D*}_{i,t} + \ln Q^{D}_{i,t-1} - \theta \ln Q^{D}_{i,t-1}$

$\ln Q^{D}_{i,t} = \theta \ln Q^{D*}_{i,t} + (1-\theta) \ln Q^{D}_{i,t-1}$

Then, by substituting in a linear function for $Q^{D*}_{i,t}$, the final form is the following:

$\ln Q^{D}_{i,t} = \theta \ln \alpha + \theta\gamma \ln p_{i,t} + \theta\beta \ln X_{i,t} + \theta\beta \ln X_{i,t-1} + (1-\theta) \ln Q^{D}_{i,t-1.}$

In this model, the θ term reflects that current demand ($Q^{D}_{i,t}$)adjusts partially to changes in desired demand ($Q^{D*}_{i,t}$). Energy demand does not fully adjust in the current period because it is a stock-flow process. In this stock-flow process, adjusting the stock usually takes more than one period but consumers can control the flow easily in the current period. Therefore, demand does not fully adjust within one period to changes in desired demand.

In more tangible terms, the "stock" refers to energy-consuming appliances that a consumer owns, such as a car, air conditioner, heater, and stove. The flow is the amount that the consumer uses the appliance. In this process, the consumer has immediate control over where the thermostat is set or how much he or she drives the car but these decisions can only affect energy consumption to a limited degree. If the consumer wants larger changes in energy demand, he or she must replace an expensive item like a car, heater, or air conditioner, which typically cannot happen immediately.

This explanation for the partial-adjustment process suggests that an ideal model for energy demand would explicitly represent consumer decisions on purchasing energy-consuming appliances and their levels of usage. Taylor (1975) discusses this issue and notes that most studies at that time had insufficient data on appliance purchases and usage to estimate such a model. Other studies have estimated price elasticity using models of this type, such as Dubin and Macfadden (1984). However, data limitations precluded estimating a similar model for different spatial scales. Therefore, we proceeded with Houthakker et. al.'s reduced-form model, which is commonly used in the literature.

By estimating the adjustment process (θ), we can estimate both short-run and long-run price elasticities. The short-run price elasticity is the long-run price elasticity (γ) multiplied by the adjustment factor (θ), which in this model refers to $\theta\gamma$, the estimated coefficient on the current period price variable. The long-run elasticity is estimated by subtracting the coefficient on the lagged demand variable ($1-\theta$) from one to get an estimate of θ and then dividing the coefficient of the current price ($\theta\gamma$) by the estimate of θ.

We estimate any spatial differences in the energy-demand relationship by adding interaction terms between indicator variables for the spatial unit of interest (region, state, or utility) and the regressors of interest (price, quantity, and income). These interaction terms allow the estimated parameters to vary, and we can analyze if price elasticities differ across geographical units.

Parameter Identification

The variables of interest in this study, energy price and quantity, are jointly determined by the interaction of energy supply and demand, which creates problems for identifying parameters in the demand equation. Ideally, we would model the energy market with a system of equations for supply and demand. With a system of equations, we could isolate movements in the demand and supply curves and use this variation to estimate the parameters in each equation. We were unable to develop a system of equations for each spatial level used in the study and instead used a reduced-form model that can identify the parameters of the demand equation under the following assumptions:

- the model includes all the factors that affect energy demand
- price changes between periods are exogenous
- the error term does not contain autocorrelation

The following discussion explains why these assumptions are necessary and then examines their plausibility.

The first assumption is necessary because identifying parameters of the demand equation, and more specifically the effect of prices on quantity, requires holding the demand curve fixed and allowing shifts in the supply curve to establish the shape of the demand curve. If the model was missing a factor that affected demand, then shifts in both demand and supply could cause the observed shifts in price and quantity but the model would attribute the changes solely to shifts in supply. More simply, the estimates in the demand equation could suffer from omitted variables bias.

The second assumption is required to isolate the effect of price on demand. In a full system of equations, changes in price affect demand and feed back into the supply equation. Therefore, prices are endogenous and determined by the equilibrium between supply and demand. Without a supply equation to capture this feedback, the model cannot identify the parameter on the endogenous variable, unless prices enter the system exogenously. The following discussion will examine some situations where prices could plausibly enter the system as an exogenous variable.

The final assumption is needed because the lagged demand term can be written as a function of past values of the error term. If autocorrelation is present, it creates correlation between the error term and the lagged demand variable, which biases estimates of the coefficient on lagged demand. The equations below show how autocorrelation is a problem.

The model equation is:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

which can be re-written as:

$$Q^D_{i,t} = \gamma\,(Q^D_{i,t-2}\gamma + X_{i,t-1}\beta + X_{i,t-2}\alpha + s_i + y_t + \varepsilon_{i,t-1}) + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

By continuing to substitute for the lagged demand term, this term could be re-written as a function of initial demand, lagged values of explanatory factors, and, most importantly, past values of the error term. Therefore, any autocorrelation in the error term ($E(\varepsilon_{i,t}, \varepsilon_{i,s}) \neq 0$ where $t \neq s$) will create correlation between the lagged demand term and the error term, which will bias estimates of the coefficient on lagged demand, γ.

The assumptions stated above for parameter identification are strong but not implausible. The following discussion addresses each assumption.

Assumption #1 - Controlling for all factors affecting demand

The model includes the own-price of the good, price of a substitute, and income, which are key variables in microeconomic decisions of demand. The model also controls for population and climate, which would also affect energy demand. In addition, the model includes lagged values of these factors, which controls for large period-to-period changes in explanatory variables. The model also controls for demand in the previous period, which in effect controls for the stock of energy-consuming appliances because the stock of appliances is unlikely to change significantly from year-to-year. Finally, the model includes fixed-effects for each cross-sectional unit and year.

The fixed-effects control for any unmeasured time-invariant effects on demand attributable to the cross-sectional unit. An example of an unmeasured time-invariant effect is energy demand patterns in states with federally-administered hydroelectric power sectors. Washington, Oregon, and Tennessee have exceptionally high per capita electricity use and low average prices. Some of this effect is due to prices, but each of these states have electricity markets dominated by large federal power agencies that have historically supplied the regions with inexpensive energy. The effect of these agencies is difficult to measure, and is likely to differ between states. Therefore, including an indicator variable for each state controls for the unique effects that agencies like the Bonneville Power Administration or Tennessee Valley Authority have on energy demand. In addition, the indicator variable controls for any other unmeasurable variables that affect energy demand. The year fixed effects control for any year-to-year variation in demand that occurs across all cross-section units. Examples of these effects are national legislation, macroeconomic trends, and national-level events that affect energy demand (war or terrorism attack).

The explanatory variables comprise a relatively comprehensive set of control variables for energy demand. The very high R^2 values (> 0.9) on the regressions indicate that the model fits the data well and explains a large amount of the variation in energy demand. One area where the model does not control for changes in demand is a state- or cross-section specific factor that changes over time. For instance, if a subset of states substantially changes their stock of energy-consuming appliances, then the model may not control for this change in demand. This situation contrasts with national consumer trends in purchasing new electronics, which the model can control for with year fixed effects.

Assumption #2 – Exogenous energy prices

The assumption of exogenous energy prices is the strongest assumption but not implausible. A public utilities commission that sets consumer rates regulates most electricity and natural gas rates. These price schedules do not change regularly and the rate setting is not exogenous. Despite these shortcomings, there are portions of a consumer's utility bill that do vary annually and this source of variation is arguably exogenous. Most utility bills contain a component that passes through changes in fuel prices to customers. Since utility rate schedules do not change regularly, much of the period-to-period variation in what consumers actually pay for electricity and natural gas is fluctuations in the fuel cost. Because these fuels are typically purchased at prices determined on national or world markets, the change in prices from fuel costs is primarily exogenous variation.

Assumption #3 – No autocorrelation in the error term

The discussion above showed that estimating the model with ordinary least squares (OLS) when autocorrelation is present will result in biased estimates. This assumption is testable and autocorrelation tests are performed on the regressions in the study. Alternate estimation methods are possible, notably instrumental variables and error component technique. In previous work, Houthakker et. al. (1974) found that OLS estimates with separate intercepts for cross-section units (fixed-effects) produced estimates that were comparable to the error component technique. Although, this finding is not generalizable to other data sets. Therefore, this analysis includes tests for autocorrelation.

We follow the test for first-order autocorrelation discussed in Wooldridge (1994; 2002). In this test, we run an OLS regression of the dependent variable on the explanatory variables and obtain the residuals. We then run an OLS regression of the residuals on the explanatory variables and lagged residuals. The coefficient on the lagged residual term is a consistent estimate for ρ and the t-statistic on the coefficient of the lagged residual term is a valid test for the null hypothesis $\rho = 0$ (no autocorrelation), where ρ represents the coefficient on the lagged error in an AR(1) model. In our results, we present the estimate of ρ and the associated t-statistic.

As stated earlier, an ideal model would include a system of equations to model the demand and supply equations of each state's energy market. The limited scope of this study excluded an extensive analysis of supply and demand in each state. We followed Houthakker's demand model because it was widely used in the literature, we could estimate differences in short- and long-run elasticities, and determine if these parameters vary geographically. Under the assumptions stated above, the model will estimate the causal effect of prices on energy demand—the focus of this study and measure how this effect varies geographically. If these conditions are not met, the estimate will reflect the correlation between the observed prices and quantities

Trend Analysis

The regional data analysis for each energy market in Chapter Four displays regional trends for residential electricity, commercial electricity, and natural gas intensity, expenditures, and expenditures as a share of income. We estimate these trends using a deterministic time trend of the following form:

Ln dependent variable = $\beta_0 + \beta_1$ year + ε

This model fits a linear time trend to our data. In most of the analyses done for this study, the trends were linear, and the model was a good fit, which was evidenced by R^2 over 0.9 (the time trend). Appendix D displays the results from the trend analysis.

Appendix B: Data Sources

The regression analyses done for this study used panel data for the 48 contiguous states. The time periods for each energy market analysis varied because of data limitations. The data on the residential electricity and natural gas markets spans 1977 to 2004. The data on commercial electricity extends only from 1977 to 1999. The data are from the following four sources: the DOE EIA, Bureau of Economic Analysis (BEA) of the Department of Commerce, the U.S. Census Bureau, and the National Oceanic and Atmospheric Administration (NOAA).

Energy Data

The sources for electricity data include the following EIA publications: *State Energy Data Report 2001*, *Electric Power Annual,* and *Electric Power Monthly*. By combining these data sources, we developed a state-level database of electricity consumption and prices for residential and commercial customers. The sources of natural-gas data include the following EIA publications: *State Energy Data Report 2001*, *Natural Gas Annual,* and *Natural Gas Monthly*. As was done for the electricity sector, for natural gas we created a state-level database on consumption and prices for residential customers.

Economic Data

We obtained economic data on gross state product, GDP deflator, and population from the Department of Commerce Bureau of Economic Analysis (BEA) "Regional Economic Accounts" Web site (see http://www.bea.gov/bea/regional/data.htm). We purchased data on commercial floorspace from McGraw-Hill Construction Dodge (http://dodge.construction.com).

Climate Data

The NOAA publishes state-level data on heating and cooling degree days. The degree-day measures quantify how far the daily average temperature deviates from 65 degrees. For instance, if a day's average temperature is 50 degrees, then the day has 15 heating degree days. If the average is 70, then the day has five cooling degree days. We constructed an annual climate index by summing heating and cooling degree-day measures, which captures annual climate variation in each state. The data on degree days are available on the NOAA website (http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html).

Appendix C: Variables and How They Were Constructed

Table C.1: Residential Electricity Regression Analysis Variables

Variable	How Variable Was Constructed/Data Source
Residential electricity consumption	Electricity consumption (Btus), residential sector (ESRCB), 1977-1999 Source: EIA *State Energy Data Report* (2001) Electricity sales (megawatt hours), residential consumers, 2000-2004 *Source*: EIA *Electric Power Annual* (2003) and *Electric Power Monthly* (2004)
Real residential electricity prices = Nominal residential electricity price / GDP deflator	Average price of electricity, residential sector (ESRCD), 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of electricity, residential consumers, 2000-2004 *Source*: EIA *Electric Power Annual* (2003) and *Electric Power Monthly* (2004)
Real residential natural gas prices Nominal residential natural gas price / GDP deflator	Average price of natural gas, residential sector (NGRCD), 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of natural gas, residential consumers, 2000-2004 *Source*: EIA *Natural Gas Annual* (2003) and *Natural Gas Monthly* (2004)
Population	State population *Source*: BEA, *Regional Accounts Data*, "Annual State Personal Income," Population table (no date)
Real disposable income per capita = Disposable Income per capita / GDP deflator	Disposable income per capita *Source:* BEA, *Regional Accounts Data*, "Annual State Personal Income," Per capita disposable personal income table (no date)
Climate index = Heating degree days + Cooling degree days	Heating degree days, cooling degree days *Source:* NOAA, *National Climatic Data Center*, "Heating and Cooling Degree Data" (no date)

Table C.2: Commercial Electricity Regression Analysis Variables

Variable	How Variable Was Constructed/ Data Source
Commercial electricity consumption	Electricity consumption (Btus), commercial sector (ESCCB) 1977-1999 *Source*: EIA *State Energy Data Report* (2001)
Real Commercial Electricity Prices = Nominal commercial electricity price / GDP deflator	Average price of electricity, commercial sector (ESCCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001)
Real Commercial Natural Gas Prices	Average price of natural gas, commercial sector (NGCCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001)
Area of commercial floorspace	Data purchased from McGraw-Hill Construction Dodge http://dodge.construction.com/—includes data on square footage of commercial floor space from 1977 - 1999 for each sate
Real gross state product = Gross state product / GDP deflator	Gross state product *Source:* BEA, *Regional Accounts Data*, "Gross State Product," (no date)
Climate index = Heating degree days + Cooling degree days	Heating degree days, Cooling degree days *Source:* NOAA, *National Climatic Data Center*, "Heating and Cooling Degree Data" (no date)

Table C.3: Residential Natural-Gas Regression Analysis Variables

Variable	How Variable Was Constructed/ Data Source
Residential natural gas consumption	Natural gas consumption (Btus), residential sector (NGRCB) , 1977-1999 *Source*: EIA *State Energy Data Report* (2001) Natural gas sales (thousands of cubic feet), residential consumers, 2000-2004 *Source*: EIA *Natural Gas Annual* (2003) and *Natural Gas Monthly* (2004)
Real residential natural gas prices = Nominal residential natural gas price / GDP deflator	Average price of natural gas, residential sector (NGRCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of natural gas, residential consumers, 2000-2004 *Source*: EIA *Natural Gas Annual* (2003) and *Natural Gas Monthly* (2004)
Real residential electricity prices = Nominal residential electricity price / GDP deflator	Average price of electricity, residential sector (ESRCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of electricity, residential consumers, 2000-2004 *Source*: EIA *Electric Power Annual* (2003) and *Electric Power Monthly* (2004)
Population	State population *Source*: BEA, *Regional Accounts Data*, "Annual State Personal Income," Population table (no date)
Real disposable income per capita = Disposable income per capita / GDP deflator	Disposable income per capita *Source:* BEA, *Regional Accounts Data*, "Annual State Personal Income," Per capita disposable personal income table (no date)
Climate index = Heating degree days + Cooling degree days	Heating degree days, cooling degree days *Source:* NOAA, *National Climatic Data Center*, "Heating and Cooling Degree Data" (no date)

Appendix D: Regression Analysis Results

In this appendix, we present the results from regression analysis at the national, regional, state, and utility levels of aggregation. We display the results for each energy market by level of aggregation.

National-Level Results

This section shows results for the residential electricity, commercial electricity, and residential natural gas markets. In the national level regressions, we estimate the model using panel data from the 48 contiguous states. We estimate the following model for these regressions:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

where $Q^D_{i,t}$ is log energy demand in state *i* and year *t*, $Q^D_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g. energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The s_i term is a state-fixed effect estimated with an indicator variable. The y_t term is a year-fixed effect also estimated with an indicator variable and $\varepsilon_{i,t}$ is a random error term.

Residential Electricity

The dependent variable in this regression was the log of electricity sold to residential electricity consumers. We controlled for the following variables:

- Lag value of dependent variable
- Log of residential electricity price
- Lag value of log of residential electricity price
- Log of per capita income
- Lag value of log of per capita income
- Log of state population
- Lag value of log of state population
- Log of residential natural gas price
- Lag value of log of residential natural gas price
- Log of climate index (heating degree days + cooling degree days)

The residential electricity market regression analysis covers the period from 1977-2004. The data from 2001 are excluded from the analysis because EIA had serious errors in the data for that year, which they have not corrected yet.

The results show that lagged quantity has a significant and positive effect on current period consumption. Current and lagged electricity prices are significant and negative. The estimates indicate that short run price elasticity (-0.24) is inelastic and similar to previous estimates in the literature. The income, population, and natural gas variables are all insignificant in the current period and significant in the lagged period. The lagged values are all positive, which is expected. Income and population increases should correspond with greater electricity demand. In this case, we consider natural gas a substitute for electricity and the positive sign for the cross-price elasticity indicates it is a substitute. Finally, the climate index has a significant and positive effect on residential electricity demand.

Table D.1: Regression results from the residential electricity market

	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
Lag quantity	0.232	0.058	4.03	0	0.119	0.345
Ln elec price	-0.243	0.049	-4.96	0	-0.339	-0.147
Lag elec price	-0.129	0.048	-2.7	0.007	-0.222	-0.035
Ln income	0.003	0.076	0.04	0.968	-0.146	0.152
Lag income	0.384	0.073	5.27	0	0.241	0.527
Ln population	-0.225	0.285	-0.79	0.43	-0.783	0.334
Lag population	0.827	0.307	2.69	0.007	0.225	1.428
Ln nat gas price	-0.005	0.028	-0.16	0.873	-0.06	0.051
Lag nat gas price	0.111	0.031	3.58	0	0.05	0.172
Ln climate	0.246	0.026	9.36	0	0.194	0.298

$R^2 = 0.99$
N = 1237

The adjusted R-squared for this model is very high—approximately 0.99. A high R-squared is typical with fixed effects models because the state and year effects included in the model usually have considerable explanatory power.

We tested for first-order autocorrelation in the error term. The estimate of ρ was -0.009 with a t-statistic of -0.69, which indicates first-order correlation is not present. We, therefore, conclude that autocorrelation does not affect consistency of the coefficient estimates or validity of the standard errors.

Commercial Electricity

The dependent variable in this regression was the log of electricity sold to commercial electricity consumers. We controlled for the following variables:

- Lag value of dependent variable
- Log of commercial electricity price
- Lag value of log of commercial electricity price
- Log of gross state product
- Lag value of log of gross state product
- Log of commercial floorspace
- Lag value of log of commercial floorspace

- Log of commercial natural gas price
- Lag value of log of commercial natural gas price
- Log of climate index (heating degree days + cooling degree days)

Table D.2: Regression results from the commercial electricity market

	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
Lagged quantity	0.785	0.034	22.81	0	0.717	0.852
Ln elec price	-0.209	0.060	-3.47	0.001	-0.327	-0.091
Lag elec price	0.148	0.052	2.85	0.004	0.046	0.250
Ln nat gas price	-0.023	0.020	-1.18	0.236	-0.061	0.015
Lag nat gas price	0.049	0.022	2.19	0.029	0.005	0.093
Ln commercial GSP	0.155	0.124	1.25	0.211	-0.088	0.398
Lag commercial GSP	-0.039	0.122	-0.32	0.747	-0.279	0.200
Ln floorspace	0.504	0.339	1.49	0.138	-0.162	1.169
Lag floorspace	-0.421	0.305	-1.38	0.169	-1.020	0.179
Ln climate	0.233	0.039	5.92	0	0.156	0.310

R^2= 0.99
n = 1034

The commercial electricity market regression analysis covers the period from 1977-1999. Later data are not included in the analysis because of consistency problems with gross state product data collected by the Bureau of Economic Analysis. In addition, data from Tennessee were excluded from this regression.

The results show that lagged quantity has a significant and positive effect on current period consumption. The magnitude is larger than the estimate for residential electricity. Current electricity price is significant and negative. The estimate indicates that short run price elasticity (-0.21) is also inelastic and similar to previous estimates in the literature. The lagged electricity price is positive and significant, which is not expected. The estimates for natural gas are insignificant for the current period and significant and positive for the lag period. Again, this suggests that natural gas is a substitute but the cross price elasticity is small. All of the GSP and floorspace variables were insignificant. Finally, the climate index has a significant and positive effect on commercial electricity demand. The magnitude is also similar to the residential electricity estimate.

The adjusted R-squared for this model is also very high—approximately 0.99. This, again, indicates the state and year effects included in the model have considerable explanatory power.

We also tested for first-order autocorrelation in the error term. The estimate of ρ was 0.021 with a t-statistic of 0.47. These results suggest first-order correlation does not affect the coefficient estimates and standard errors in this model.

Residential Natural Gas

The dependent variable in this regression was the log of natural gas sold to residential natural gas consumers. We controlled for the following variables:

- Lag value of dependent variable
- Log of residential natural gas price
- Lag value of log of residential natural gas price
- Log of per capita income
- Lag value of log of per capita income
- Log of state population
- Lag value of log of state population
- Log of residential electricity price
- Lag value of log of residential electricity price
- Log of climate index (heating degree days + cooling degree days)

Table D.3: Results from natural gas market regression analysis

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Lag quantity	0.577	0.024	24.44	0	0.531	0.623
Ln nat gas price	-0.132	0.031	-4.24	0	-0.193	-0.071
Lag nat gas price	-0.106	0.031	-3.42	0.001	-0.167	-0.045
Ln elec price	0.034	0.053	0.64	0.521	-0.070	0.138
Lag elec price	0.146	0.052	2.8	0.005	0.044	0.248
Ln income	0.261	0.123	2.13	0.034	0.020	0.503
Lag income	0.167	0.113	1.48	0.139	-0.054	0.388
Ln population	1.169	0.449	2.6	0.009	0.287	2.051
Lag population	-0.717	0.449	-1.6	0.11	-1.598	0.163
Ln climate	0.181	0.042	4.29	0	0.098	0.264

$R^2 = 0.96$
n = 1210

The residential natural gas market regression analysis covers the period from 1977-2004. The regression includes data from all time periods. It excludes the state of Maine from the analysis. Gas volumes sold in Maine are very small in absolute terms and relative to all other states. Since the absolute volumes traded are small, small changes had large effects in % changes and disproportionately affected the price elasticity estimates. Since the market there is small compared to the rest of the country, the analysis excludes it.

The results show that the lagged quantity is significant and the magnitude is similar to the estimate in commercial electricity. Natural gas price is significant and negative in the current and lagged period. The estimate of short-term price elasticity is –0.132, which is smaller in absolute value than the estimates for both electricity markets. The current price of electricity is insignificant but the lagged value is positive and significant. This is further evidence that electricity and natural gas are substitutes for residential consumers.

The magnitude of the cross price elasticity is also small in this case. The estimates for income and population are positive and significant in the current period but insignificant in the lagged period. The elasticity for population (1.17) is large relative to the other estimates, which indicates population change has a strong effect on demand in this market.

The adjusted R-squared for this model is again very high—approximately 0.96. The fixed effects included in the model also have considerable explanatory power for this market.

We tested for first-order autocorrelation and found that it may be present in the error term. The estimate of ρ was -0.342 with a t-statistic of -6.75. Based on this result, we estimated the model assuming an AR(1) structure in the error term, which should correct the standard errors. However, autocorrelation still affects consistency of the estimate on the lagged demand term.

Regional-Level Results

This section shows regional level results for the residential electricity, commercial electricity, and residential natural gas markets. In the regional level regressions, we estimate the model using panel data from the 48 contiguous states. We estimate the following model for these regressions:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + (r_i \times Q^D_{i,t-1})\,\gamma'_Q + (r_i \times \ln \text{elec price}_{i,t})\,\beta'_P + (r_i \times \ln \text{income}_{i,t})\,\beta'_I + s_i + y_t + \varepsilon_{i,t}$$

where $Q^D_{i,t}$ is log energy demand in state i and year t, $Q^D_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g. energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The interaction terms interact a region indicator variable with lagged quantity, current prices, and current income. The corresponding region-specific coefficient estimates are $(\gamma + \gamma'_Q)$ for lagged quantity, $(\beta_P + \beta'_P)$ for prices, and $(\beta_I + \beta'_I)$ for income. The s_i term is a state-fixed effect estimated with an indicator variable. The y_t term is year-fixed effect also estimated with an indicator variable and $\varepsilon_{i,t}$ is a random error term.

Residential Electricity

The table shows that demand response in the South Atlantic and East South Central is most elastic and the East North Central has the most inelastic demand response. All of the estimates are negative and statistically significant, except the East North Central. The estimates also indicate regional differences in electricity demand. The estimates for the South Atlantic and East South Central have statistically significant differences from the East North Central. A Wald Test on the South Atlantic and East North Central coefficients rejects the null hypothesis that they are equal ($F(1,1130) = 14.59$; $p = 0.0001$). A Wald Test on the East South Central and East North Central coefficients also rejects that they are equal (F(1,1130) = 10.37; p=0.0013). Overall, the regression results show clear statistically significant differences in price elasticities between the regions.

Table D.4: Estimated short-run price elasticities for the residential electricity market

Short run price elasticity

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
South Atlantic	-0.318	0.047	-6.77	0	-0.41	-0.226
East South Central	-0.266	0.071	-3.74	0	-0.405	-0.126
Mid Atlantic	-0.232	0.069	-3.36	0.001	-0.368	-0.096
Mountain	-0.211	0.038	-5.55	0	-0.285	-0.136
New England	-0.192	0.046	-4.2	0	-0.281	-0.102
Pacific Coast	-0.188	0.051	-3.69	0	-0.288	-0.088
West North Central	-0.163	0.054	-3.02	0.003	-0.269	-0.057
West South Central	-0.127	0.051	-2.52	0.012	-0.227	-0.028
East North Central	-0.054	0.053	-1.01	0.312	-0.158	0.051

We tested for first-order autocorrelation in the error term and the estimate of ρ was -0.003 with a t-statistic of -0.26. The estimate indicates that first-order autocorrelation does not affect the error term and this model. Therefore, autocorrelation does not affect the estimate of lagged demand and the inference based on the standard errors is valid.

Table D.5: Estimated long-run price elasticities for the residential electricity market

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
East South Central	-0.618	0.144	-4.3	0	-0.900	-0.336
South Atlantic	-0.352	0.051	-6.86	0	-0.453	-0.251
New England	-0.325	0.074	-4.37	0	-0.471	-0.179
Mountain	-0.267	0.048	-5.52	0	-0.362	-0.172
Pacific Coast	-0.254	0.078	-3.27	0.001	-0.407	-0.101
Mid Atlantic	-0.247	0.075	-3.28	0.001	-0.395	-0.099
West North Central	-0.244	0.081	-3.01	0.003	-0.403	-0.085
West South Central	-0.174	0.070	-2.48	0.013	-0.311	-0.036
East North Central	-0.058	0.057	-1.02	0.309	-0.169	0.054

Long run price elasticities are calculated by dividing the coefficient estimate on current electricity prices by 1 – the coefficient of lagged quantity. The long-run elasticities are larger for all of the regions, which is expected and follows the general findings from previous research. The pattern of results is also similar to the short-run elasticity results. The East South Central and South Atlantic regions have the most elastic demand and the East North Central is the most inelastic. Again, all of the estimates have the expected sign and significant, except for the East North Central.

Commercial Electricity

We used the same regression model to estimate the regional-level commercial electricity market.

Table D.6: Short-run price elasticities for commercial electricity with and without Tennessee

Short-Run Price Elasticity – with Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
East South Central	-0.759	0.322	-2.36	0.019	-1.391	-0.127
Pacific Coast	-0.364	0.099	-3.67	0	-0.559	-0.169
New England	-0.273	0.101	-2.71	0.007	-0.470	-0.076
Mountain	-0.258	0.126	-2.04	0.042	-0.505	-0.010
West South Central	-0.250	0.114	-2.19	0.029	-0.475	-0.026
East North Central	-0.237	0.111	-2.13	0.033	-0.455	-0.019
West North Central	-0.233	0.132	-1.76	0.078	-0.491	0.026
South Atlantic	-0.226	0.106	-2.13	0.034	-0.435	-0.017
Mid Atlantic	-0.215	0.081	-2.64	0.009	-0.374	-0.055

Short-Run Price Elasticity – without Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.306	0.076	-4.04	0	-0.455	-0.158
East South Central	-0.271	0.120	-2.25	0.024	-0.507	-0.035
New England	-0.212	0.079	-2.69	0.007	-0.367	-0.057
East North Central	-0.181	0.089	-2.04	0.042	-0.356	-0.007
Mid Atlantic	-0.180	0.058	-3.11	0.002	-0.293	-0.066
West South Central	-0.179	0.084	-2.12	0.034	-0.345	-0.014
Mountain	-0.178	0.102	-1.74	0.082	-0.377	0.022
West North Central	-0.166	0.109	-1.52	0.128	-0.380	0.048
South Atlantic	-0.158	0.082	-1.94	0.053	-0.318	0.002

The table shows that the data from Tennessee affect all of the results, especially the East South Central region. The EIA appears to have an error in this data series. In 2001, Tennessee's commercial electricity output doubles and then returns to previous levels in 2002. Due to this apparent error, we excluded Tennessee from the national-level results.

The estimates in the without Tennessee case are similar to the residential electric market except no region is markedly lower than the others. With a much closer range of estimates, none of these regional estimates have statistically significant differences between them. However, most are significantly different from zero (six out of nine). Overall, the estimates suggest that price elasticities vary between regions but the magnitude of the differences is not very large. In addition, the differences are difficult to detect with a sample of this size.

We tested for first-order autocorrelation in the models including and excluding Tennessee. In the model including Tennessee, the estimate of ρ was 0.071 with a t-statistic of 1.18. In the model excluding Tennessee, the estimate of ρ was 0.078 with a t-statistic of 1.26. These estimates suggest first-order autocorrelation was not a problem in either model.

Table D.7: Long-run price elasticity estimates for commercial electricity

Long-Run Price Elasticity – with Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
East South Central	-3.106	1.595	-1.95	0.052	-6.236	0.025
Mid Atlantic	-1.737	1.598	-1.09	0.277	-4.872	1.398
Pacific Coast	-1.578	1.018	-1.55	0.121	-3.576	0.419
New England	-1.519	1.118	-1.36	0.175	-3.713	0.676
South Atlantic	-1.508	0.745	-2.02	0.043	-2.969	-0.046
East North Central	-1.156	0.644	-1.8	0.073	-2.419	0.107
Mountain	-0.901	0.448	-2.01	0.044	-1.781	-0.022
West North Central	-0.830	0.573	-1.45	0.148	-1.955	0.294
West South Central	-0.497	0.269	-1.85	0.065	-1.025	0.031

Long-Run Price Elasticity – without Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Mid Atlantic	-1.422	1.149	-1.24	0.216	-3.677	0.832
Pacific Coast	-1.365	0.864	-1.58	0.114	-3.060	0.330
New England	-1.254	0.988	-1.27	0.205	-3.193	0.686
South Atlantic	-1.140	0.604	-1.89	0.059	-2.326	0.045
East South Central	-0.995	0.524	-1.9	0.058	-2.024	0.033
East North Central	-0.882	0.502	-1.76	0.079	-1.866	0.103
Mountain	-0.626	0.351	-1.78	0.075	-1.315	0.063
West North Central	-0.589	0.459	-1.28	0.2	-1.489	0.311
West South Central	-0.371	0.208	-1.78	0.075	-0.779	0.038

The long-run estimates are considerably larger in absolute magnitude than the short-run estimates and also larger than the residential electricity long-run estimates. Comparison between the two models shows that including Tennessee increases the magnitude of the estimates, especially for the East South Central region. When excluding this state, the magnitudes of the estimates drop, but no estimate is statistically significant from zero. The confidence intervals show that the variance of the estimates is large and they lack precision.

Residential Natural Gas

Tables D.8 and D.9 compare short-run and long-run elasticity estimates for regressions that include and exclude the state of Maine. Maine sells very low volumes of natural gas and small changes in the market can have large relative effects. It appears that the elasticity estimate is considerably larger in Maine for this reason and comparison across the tables shows that including this state has a substantial effect on the results.

Table D.8: Short run price elasticity for natural gas

Short-Run Price Elasticity – with Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
New England	-0.336	0.064	-5.28	0	-0.461	-0.211
Mid Atlantic	-0.227	0.094	-2.4	0.016	-0.412	-0.042
Pacific Coast	-0.184	0.072	-2.55	0.011	-0.325	-0.043
Mountain	-0.183	0.050	-3.63	0	-0.282	-0.084
West North Central	-0.170	0.053	-3.24	0.001	-0.273	-0.067
East North Central	-0.155	0.062	-2.49	0.013	-0.277	-0.033
East South Central	-0.142	0.071	-2.01	0.045	-0.281	-0.003
South Atlantic	-0.114	0.057	-2	0.046	-0.225	-0.002
West South Central	-0.078	0.068	-1.13	0.258	-0.212	0.057

Short-Run Price Elasticity – without Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Mid Atlantic	-0.174	0.081	-2.15	0.032	-0.332	-0.015
Mountain	-0.164	0.043	-3.85	0	-0.248	-0.080
Pacific Coast	-0.163	0.062	-2.63	0.009	-0.285	-0.042
West North Central	-0.138	0.044	-3.11	0.002	-0.226	-0.051
New England	-0.127	0.064	-1.98	0.048	-0.253	-0.001
East North Central	-0.120	0.053	-2.26	0.024	-0.225	-0.016
East South Central	-0.100	0.061	-1.64	0.101	-0.219	0.019
South Atlantic	-0.073	0.048	-1.5	0.133	-0.168	0.022
West South Central	-0.049	0.059	-0.84	0.4	-0.165	0.066

Table D.9: Short run price elasticity for natural gas

Long-Run Price Elasticity – with Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.630	0.261	-2.41	0.016	-1.142	-0.118
New England	-0.593	0.115	-5.15	0	-0.819	-0.367
Mid Atlantic	-0.469	0.192	-2.44	0.015	-0.847	-0.091
Mountain	-0.440	0.123	-3.57	0	-0.681	-0.198
East South Central	-0.396	0.222	-1.78	0.075	-0.833	0.040
West North Central	-0.298	0.093	-3.19	0.001	-0.481	-0.115
South Atlantic	-0.241	0.122	-1.96	0.05	-0.481	0.000
East North Central	-0.232	0.098	-2.37	0.018	-0.423	-0.040
West South Central	-0.126	0.114	-1.1	0.27	-0.350	0.098

Long-Run Price Elasticity – without Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.452	0.173	-2.61	0.009	-0.791	-0.112
Mountain	-0.355	0.092	-3.84	0	-0.536	-0.174
Mid Atlantic	-0.338	0.153	-2.2	0.028	-0.638	-0.037
New England	-0.305	0.158	-1.93	0.054	-0.614	0.005
East South Central	-0.247	0.161	-1.54	0.125	-0.562	0.068
West North Central	-0.220	0.071	-3.11	0.002	-0.358	-0.081
East North Central	-0.171	0.078	-2.19	0.029	-0.323	-0.018
South Atlantic	-0.141	0.095	-1.49	0.136	-0.327	0.045
West South Central	-0.071	0.085	-0.83	0.406	-0.239	0.097

The results show that including Maine in the analysis increases the absolute magnitude of all the elasticity estimates, especially the New England region. Since it is a tiny market compared to the other states, we will focus on the results excluding this state and have also excluded Maine in the other regressions for this market.

The residential natural gas estimates are all negative, as expected, but smaller in absolute magnitude than the electricity markets. Fewer regions are statistically significant also. Five regions are significant for both the short-run and long-run estimates.

The tests for first-order autocorrelation in the error term suggest autocorrelation exists in both models. In the model including Maine, the estimate of ρ was -0.195 with a t-statistic of -3.11. In the model excluding Maine, the estimate of ρ was -0.369 with a t-statistic of -6.75. In response to these findings, we estimated the results presented above assuming an AR(1) structure in the error terms.

State-Level Results

This section shows state-level regression results for the residential electricity, commercial electricity, and residential natural gas markets. The state-level regression is similar to the region-level model except the interaction terms are at the state level. We estimate the following model for these regressions:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + (s_i \text{ x } Q^D_{i,t-1})\,\gamma'_Q + (s_i \text{ x ln elec price}_{i,t})\,\beta'_P + (s_i \text{ x ln income}_{i,t})\,\beta'_I + s_i + y_t + \varepsilon_{i,t}$$

where $Q^D_{i,t}$ is log energy demand in state *i* and year *t*, $Q^D_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g. energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The interaction terms interact a state indicator variable with lagged quantity, current prices, and current income. The corresponding state-specific coefficient estimates are $(\gamma + \gamma'_Q)$ for lagged quantity, $(\beta_P + \beta'_P)$ for prices, and $(\beta_I + \beta'_I)$ for income. The s_i term is a state-fixed effect estimated with an indicator variable. The y_t term is year-fixed effect also estimated with an indicator variable and $\varepsilon_{i,t}$ is a random error term.

Residential Electricity

Table D.10: State-level results for short-run price elasticity.

Short run price elasticity

	Region	Coeff	Std. Error	T-stat	P-value	95% Conf Interval	
Delaware	SA	-1.026	0.106	-9.71	0	-1.234	-0.819
Arkansas	WSC	-0.618	0.137	-4.51	0	-0.886	-0.349
Tennessee	ESC	-0.352	0.137	-2.58	0.01	-0.621	-0.084
Georgia	SA	-0.352	0.158	-2.22	0.026	-0.662	-0.041
New Hampshire	NE	-0.347	0.086	-4.05	0	-0.516	-0.179
California	PC	-0.322	0.101	-3.17	0.002	-0.521	-0.123
Missouri	WNC	-0.296	0.118	-2.51	0.012	-0.527	-0.065
Maine	NE	-0.275	0.076	-3.61	0	-0.425	-0.126
Oregon	PC	-0.258	0.100	-2.57	0.01	-0.455	-0.061
New Jersey	MA	-0.231	0.094	-2.47	0.014	-0.415	-0.047
Florida	SA	-0.218	0.092	-2.38	0.017	-0.398	-0.039
Michigan	ENC	-0.206	0.298	-0.69	0.489	-0.791	0.378
Mississippi	ESC	-0.204	0.146	-1.4	0.162	-0.490	0.082
Alabama	ESC	-0.190	0.110	-1.72	0.086	-0.407	0.027
Pennsylvania	MA	-0.151	0.101	-1.49	0.138	-0.349	0.048
Virginia	SA	-0.148	0.174	-0.85	0.398	-0.490	0.195
South Dakota	WNC	-0.141	0.123	-1.15	0.25	-0.382	0.099
Ohio	ENC	-0.135	0.140	-0.97	0.333	-0.410	0.139
New York	MA	-0.125	0.119	-1.06	0.291	-0.358	0.107

North Carolina	SA	-0.113	0.115	-0.98	0.326	-0.340	0.113
Massachusetts	NE	-0.108	0.105	-1.03	0.304	-0.315	0.098
Rhode Island	NE	-0.103	0.092	-1.12	0.262	-0.283	0.077
Illinois	ENC	-0.090	0.070	-1.3	0.195	-0.227	0.046
Connecticut	NE	-0.090	0.077	-1.17	0.243	-0.240	0.061
Washington	PC	-0.079	0.061	-1.3	0.195	-0.199	0.041
Iowa	WNC	-0.074	0.128	-0.58	0.562	-0.324	0.176
Texas	WSC	-0.062	0.077	-0.81	0.419	-0.213	0.089
Arizona	M	-0.059	0.094	-0.63	0.532	-0.243	0.125
Montana	M	-0.056	0.119	-0.47	0.637	-0.289	0.177
Indiana	ENC	-0.054	0.094	-0.58	0.564	-0.239	0.130
North Dakota	WNC	-0.046	0.093	-0.49	0.624	-0.229	0.137
Oklahoma	WSC	-0.004	0.080	-0.06	0.956	-0.161	0.152
Louisiana	WSC	0.048	0.071	0.68	0.497	-0.091	0.187
New Mexico	M	0.049	0.099	0.49	0.622	-0.145	0.242
West Virginia	SA	0.052	0.177	0.29	0.769	-0.295	0.398
Nevada	M	0.057	0.073	0.79	0.431	-0.085	0.200
Kentucky	ESC	0.082	0.110	0.75	0.453	-0.133	0.297
South Carolina	SA	0.084	0.100	0.84	0.402	-0.113	0.281
Idaho	M	0.089	0.087	1.02	0.308	-0.082	0.261
Vermont	NE	0.109	0.208	0.52	0.602	-0.300	0.517
Utah	M	0.120	0.073	1.64	0.102	-0.024	0.264
Kansas	WNC	0.128	0.077	1.66	0.097	-0.023	0.280
Maryland	SA	0.136	0.171	0.8	0.427	-0.199	0.471
Minnesota	WNC	0.140	0.134	1.05	0.294	-0.122	0.402
Wisconsin	ENC	0.154	0.085	1.81	0.071	-0.013	0.321
Nebraska	WNC	0.178	0.123	1.46	0.146	-0.062	0.419
Wyoming	M	0.219	0.097	2.27	0.023	0.030	0.409
Colorado	M	0.599	0.129	4.64	0	0.345	0.852

The results show a wide range in estimates at the state level. Most estimates have the expected negative sign, but eleven states are in the positive range. Most of the positive estimates are near zero and their confidence intervals include the negative range. Wyoming and Colorado are significant, positive, and relatively large in absolute magnitude. Delaware and Arkansas have the largest magnitudes in the negative range. Between these two ends of the range, thirty states have negative elasticities in the range seen in the national- and regional-level results (near 0 to -0.3). In this range, the confidence interval for most states includes the national-level estimate (-0.24).

The states with elasticities in the extreme parts of the range indicate a possible omitted variable. Colorado experienced a sharp growth in electricity demand in the early 1980's, which was coincident with a period of rising prices. This short increase is unexplained by other regressors in the model. Houthakker et. al. (1974) noticed a correlation between rural states and low/positive elasticities. The same pattern occurs in these results. Nearly all the states with positive elasticities are predominantly rural.

Table D.11: Long Run Price Elasticity

	Region	Coeff	Std. Error	T-stat	P-value	95% Conf	Interval
Delaware	SA	-0.999	0.093	-10.73	0	-1.182	-0.816
Arkansas	WSC	-0.539	0.069	-7.8	0	-0.675	-0.404
California	PC	-0.492	0.273	-1.8	0.072	-1.027	0.044
New Hampshire	NE	-0.470	0.127	-3.69	0	-0.720	-0.220
Maine	NE	-0.437	0.144	-3.03	0.002	-0.720	-0.154
Tennessee	ESC	-0.401	0.131	-3.07	0.002	-0.658	-0.145
Georgia	SA	-0.313	0.114	-2.75	0.006	-0.536	-0.090
Missouri	WNC	-0.263	0.092	-2.86	0.004	-0.444	-0.083
Florida	SA	-0.244	0.085	-2.87	0.004	-0.411	-0.077
Michigan	ENC	-0.244	0.310	-0.79	0.432	-0.853	0.365
New Jersey	MA	-0.240	0.100	-2.41	0.016	-0.436	-0.045
Mississippi	ESC	-0.238	0.180	-1.32	0.186	-0.591	0.115
Oregon	PC	-0.236	0.098	-2.41	0.016	-0.429	-0.044
Alabama	ESC	-0.221	0.114	-1.94	0.053	-0.444	0.003
Virginia	SA	-0.184	0.213	-0.86	0.388	-0.601	0.234
New York	MA	-0.178	0.169	-1.05	0.293	-0.509	0.154
South Dakota	WNC	-0.166	0.152	-1.09	0.277	-0.465	0.133
Rhode Island	NE	-0.164	0.162	-1.01	0.313	-0.481	0.154
Pennsylvania	MA	-0.163	0.110	-1.49	0.137	-0.379	0.052
Washington	PC	-0.161	0.149	-1.08	0.279	-0.453	0.131
Massachusetts	NE	-0.150	0.160	-0.93	0.35	-0.464	0.165
Ohio	ENC	-0.136	0.138	-0.98	0.327	-0.407	0.136
Connecticut	NE	-0.123	0.101	-1.21	0.225	-0.321	0.076
North Carolina	SA	-0.109	0.102	-1.06	0.288	-0.310	0.092
Iowa	WNC	-0.092	0.161	-0.57	0.568	-0.408	0.224
Texas	WSC	-0.081	0.100	-0.81	0.418	-0.276	0.115
Montana	M	-0.079	0.174	-0.46	0.648	-0.420	0.261
Illinois	ENC	-0.076	0.052	-1.46	0.145	-0.179	0.026
Arizona	M	-0.066	0.104	-0.63	0.528	-0.270	0.138
Indiana	ENC	-0.056	0.095	-0.59	0.557	-0.243	0.131
North Dakota	WNC	-0.055	0.113	-0.49	0.625	-0.277	0.167
Oklahoma	WSC	-0.005	0.094	-0.06	0.956	-0.190	0.179
Nevada	M	0.046	0.057	0.81	0.418	-0.066	0.158
West Virginia	SA	0.053	0.179	0.29	0.769	-0.299	0.404
New Mexico	M	0.059	0.119	0.5	0.62	-0.175	0.293
Louisiana	WSC	0.060	0.086	0.7	0.486	-0.108	0.228
South Carolina	SA	0.089	0.106	0.84	0.401	-0.119	0.297
Idaho	M	0.106	0.104	1.02	0.309	-0.098	0.310
Utah	M	0.123	0.075	1.64	0.102	-0.025	0.271
Kentucky	ESC	0.134	0.174	0.77	0.441	-0.207	0.475
Kansas	WNC	0.143	0.084	1.71	0.088	-0.021	0.307
Minnesota	WNC	0.202	0.196	1.03	0.303	-0.183	0.586
Nebraska	WNC	0.206	0.135	1.52	0.129	-0.060	0.471
Maryland	SA	0.206	0.255	0.81	0.419	-0.294	0.706

Vermont	NE	0.281	0.580	0.48	0.629	-0.857	1.419
Wyoming	M	0.296	0.127	2.33	0.02	0.047	0.545
Wisconsin	ENC	0.302	0.183	1.65	0.099	-0.057	0.661
Colorado	M	0.666	0.105	6.36	0	0.461	0.872

The long run elasticity estimates show greater variability. Only 12 states have statistically significant estimates and two of those are positive. Similar to the other markets, long run price elasticities are generally greater than the short run estimates.

We tested for first-order autocorrelation in the state-level residential electricity model and found it does not appear to affect the error term. The estimate of ρ was -0.004 with a t-statistic of -0.89. The results indicate that autocorrelation does not affect consistency of estimates on the lagged demand term and that inference based on the existing standard errors is valid.

Commercial Electricity

Table D.12: Short-run elasticity estimates for commercial electricity

Short Run Commercial Electricity

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Tennessee	-3.363	2.314	-1.45	0.147	-7.90	1.18
Maryland	-1.086	0.946	-1.15	0.251	-2.94	0.77
Nevada	-1.016	0.668	-1.52	0.129	-2.33	0.30
Michigan	-0.948	0.583	-1.63	0.105	-2.09	0.20
Vermont	-0.805	0.212	-3.79	0	-1.22	-0.39
Alabama	-0.656	0.288	-2.28	0.023	-1.22	-0.09
South Carolina	-0.506	0.195	-2.59	0.01	-0.89	-0.12
Oregon	-0.477	0.103	-4.62	0	-0.68	-0.27
Illinois	-0.450	0.144	-3.13	0.002	-0.73	-0.17
Montana	-0.425	0.515	-0.83	0.409	-1.44	0.59
Rhode Island	-0.400	0.107	-3.75	0	-0.61	-0.19
Idaho	-0.337	0.282	-1.2	0.232	-0.89	0.22
Washington	-0.326	0.255	-1.28	0.201	-0.83	0.17
Massachusetts	-0.311	0.099	-3.15	0.002	-0.50	-0.12
New Jersey	-0.310	0.109	-2.85	0.004	-0.52	-0.10
Iowa	-0.309	0.183	-1.69	0.092	-0.67	0.05
Maine	-0.307	0.106	-2.9	0.004	-0.52	-0.10
Texas	-0.281	0.112	-2.51	0.012	-0.50	-0.06
Arizona	-0.246	0.193	-1.27	0.203	-0.63	0.13
Kansas	-0.237	0.113	-2.1	0.036	-0.46	-0.02
Ohio	-0.220	0.215	-1.02	0.306	-0.64	0.20
California	-0.201	0.123	-1.63	0.104	-0.44	0.04
Connecticut	-0.192	0.114	-1.69	0.092	-0.42	0.03

Virginia	-0.192	0.138	-1.39	0.164	-0.46	0.08
Delaware	-0.186	0.163	-1.14	0.256	-0.51	0.14
New Mexico	-0.183	0.158	-1.16	0.246	-0.49	0.13
Minnesota	-0.173	0.183	-0.95	0.344	-0.53	0.19
Mississippi	-0.165	0.224	-0.74	0.462	-0.60	0.27
West Virginia	-0.155	0.120	-1.29	0.197	-0.39	0.08
Utah	-0.152	0.140	-1.08	0.279	-0.43	0.12
New York	-0.150	0.086	-1.75	0.081	-0.32	0.02
Oklahoma	-0.108	0.153	-0.7	0.482	-0.41	0.19
Arkansas	-0.108	0.153	-0.7	0.481	-0.41	0.19
Louisiana	-0.098	0.119	-0.83	0.408	-0.33	0.13
Pennsylvania	-0.091	0.073	-1.24	0.216	-0.23	0.05
Florida	-0.070	0.121	-0.58	0.561	-0.31	0.17
North Dakota	-0.055	0.453	-0.12	0.903	-0.94	0.83
Kentucky	-0.053	0.122	-0.44	0.664	-0.29	0.19
Wisconsin	-0.033	0.199	-0.17	0.868	-0.42	0.36
North Carolina	-0.028	0.106	-0.26	0.793	-0.24	0.18
Missouri	-0.022	0.136	-0.16	0.872	-0.29	0.25
Colorado	0.016	0.140	0.12	0.907	-0.26	0.29
Wyoming	0.042	0.132	0.32	0.749	-0.22	0.30
Indiana	0.102	0.174	0.59	0.556	-0.24	0.44
New Hampshire	0.146	0.341	0.43	0.669	-0.52	0.81
Nebraska	0.172	0.157	1.1	0.273	-0.14	0.48
Georgia	0.219	0.117	1.88	0.061	-0.01	0.45
South Dakota	0.335	0.581	0.58	0.564	-0.80	1.48

The state-level estimates lack precision. In comparison to the residential data, the commercial electricity quantity data have much greater variability, which results in less precise estimates for price elasticity. As a result, only nine states have statistically significant results. A data error appears to cause the large estimate for Tennessee. This data problem was discussed in the regional level section.

The estimates are distributed more evenly throughout the range compared to residential electricity. There are also fewer positive estimates and none of the positive estimates are significant.

Table D.13: Long Run Commercial Electricity Elasticity Estimates

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Tennessee	-10.338	4.001	-2.58	0.01	-18.19	-2.48
Maryland	-7.467	3.332	-2.24	0.025	-14.01	-0.93
Alabama	-4.892	4.255	-1.15	0.251	-13.24	3.46
Nevada	-1.730	0.859	-2.01	0.044	-3.42	-0.04
Michigan	-1.496	0.537	-2.79	0.005	-2.55	-0.44
Rhode Island	-1.315	1.232	-1.07	0.286	-3.73	1.10
Ohio	-1.243	1.500	-0.83	0.407	-4.19	1.70

Washington	-1.210	2.205	-0.55	0.583	-5.54	3.12
Montana	-1.177	1.349	-0.87	0.383	-3.82	1.47
Massachusetts	-1.010	0.719	-1.4	0.161	-2.42	0.40
Vermont	-0.899	0.318	-2.83	0.005	-1.52	-0.28
Illinois	-0.804	0.248	-3.24	0.001	-1.29	-0.32
New Jersey	-0.740	0.431	-1.72	0.086	-1.59	0.11
Oregon	-0.678	0.497	-1.36	0.173	-1.65	0.30
South Carolina	-0.623	0.146	-4.28	0	-0.91	-0.34
Connecticut	-0.516	0.540	-0.96	0.34	-1.57	0.54
Delaware	-0.514	0.622	-0.83	0.409	-1.73	0.71
Iowa	-0.493	0.276	-1.79	0.074	-1.04	0.05
West Virginia	-0.489	0.401	-1.22	0.223	-1.28	0.30
Pennsylvania	-0.412	0.493	-0.84	0.404	-1.38	0.56
Minnesota	-0.396	0.459	-0.86	0.389	-1.30	0.51
Utah	-0.394	0.474	-0.83	0.406	-1.32	0.54
Texas	-0.384	0.158	-2.44	0.015	-0.69	-0.07
Mississippi	-0.379	0.550	-0.69	0.491	-1.46	0.70
New Mexico	-0.372	0.468	-0.79	0.428	-1.29	0.55
Kansas	-0.371	0.277	-1.34	0.182	-0.91	0.17
Idaho	-0.366	0.381	-0.96	0.337	-1.11	0.38
Virginia	-0.365	0.297	-1.23	0.22	-0.95	0.22
Maine	-0.348	0.154	-2.26	0.024	-0.65	-0.05
Arizona	-0.330	0.258	-1.28	0.201	-0.84	0.18
California	-0.301	0.266	-1.13	0.259	-0.82	0.22
New York	-0.297	0.257	-1.15	0.249	-0.80	0.21
Oklahoma	-0.147	0.227	-0.65	0.516	-0.59	0.30
North Dakota	-0.145	1.248	-0.12	0.908	-2.59	2.30
Arkansas	-0.132	0.215	-0.62	0.539	-0.55	0.29
Louisiana	-0.130	0.172	-0.76	0.449	-0.47	0.21
Florida	-0.118	0.201	-0.59	0.558	-0.51	0.28
Kentucky	-0.080	0.212	-0.38	0.707	-0.50	0.34
North Carolina	-0.066	0.265	-0.25	0.802	-0.59	0.45
Missouri	-0.057	0.366	-0.16	0.875	-0.78	0.66
Wisconsin	-0.034	0.208	-0.16	0.871	-0.44	0.37
Colorado	0.038	0.325	0.12	0.907	-0.60	0.68
Wyoming	0.153	0.470	0.33	0.745	-0.77	1.08
New Hampshire	0.306	0.579	0.53	0.597	-0.83	1.44
Georgia	0.327	0.173	1.89	0.059	-0.01	0.67
Indiana	0.353	0.651	0.54	0.587	-0.92	1.63
South Dakota	0.434	0.651	0.67	0.505	-0.84	1.71
Nebraska	0.441	0.354	1.25	0.213	-0.25	1.14

The long run commercial electricity estimates appear sensitive to the model specification. Given this model, when the coefficient of lagged quantity nears one, the denominator of the expression decreases and the estimate can become very large. This occurs in the first three states on the list: Tennessee, Maryland, and Alabama.

The remaining estimates are generally larger than the short run estimates. The states also remain in relatively similar positions to the short run estimates.

We tested for first-order autocorrelation in the state-level commercial electricity model and found it does not appear to affect the error term. The estimate of ρ was 0.018 with a t-statistic of 0.50. The results indicate that autocorrelation does not affect consistency of estimates on the lagged demand term and that inference based on the existing standard errors is valid.

Natural Gas

Table D.14: Regression results for short run residential natural gas elasticity.

Short Run Natural Gas

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Maine	-0.745	0.467	-1.59	0.111	-1.662	0.172
Vermont	-0.281	0.084	-3.35	0.001	-0.445	-0.117
Illinois	-0.229	0.084	-2.72	0.007	-0.394	-0.064
New Hampshire	-0.225	0.093	-2.41	0.016	-0.408	-0.042
Montana	-0.217	0.079	-2.75	0.006	-0.372	-0.062
South Carolina	-0.202	0.141	-1.43	0.154	-0.479	0.076
New Mexico	-0.190	0.111	-1.71	0.088	-0.408	0.028
Virginia	-0.189	0.104	-1.81	0.07	-0.393	0.015
West Virginia	-0.184	0.083	-2.22	0.027	-0.347	-0.021
North Dakota	-0.183	0.063	-2.88	0.004	-0.308	-0.059
Alabama	-0.170	0.103	-1.64	0.101	-0.372	0.033
Kansas	-0.167	0.071	-2.37	0.018	-0.305	-0.028
Washington	-0.166	0.109	-1.53	0.125	-0.380	0.047
Arkansas	-0.151	0.080	-1.89	0.059	-0.308	0.006
North Carolina	-0.149	0.102	-1.46	0.145	-0.350	0.052
Missouri	-0.143	0.068	-2.11	0.035	-0.276	-0.010
Indiana	-0.139	0.063	-2.21	0.027	-0.263	-0.015
Kentucky	-0.137	0.059	-2.31	0.021	-0.253	-0.021
Ohio	-0.127	0.076	-1.68	0.093	-0.276	0.021
Pennsylvania	-0.117	0.089	-1.31	0.19	-0.291	0.058
South Dakota	-0.112	0.077	-1.46	0.144	-0.263	0.039
Tennessee	-0.110	0.101	-1.09	0.277	-0.308	0.088
Maryland	-0.106	0.109	-0.97	0.331	-0.319	0.108
Colorado	-0.102	0.069	-1.48	0.14	-0.237	0.033
Minnesota	-0.100	0.066	-1.52	0.129	-0.229	0.029
California	-0.098	0.119	-0.82	0.41	-0.332	0.135
Iowa	-0.098	0.090	-1.09	0.278	-0.275	0.079
Wisconsin	-0.098	0.066	-1.49	0.138	-0.227	0.031
Rhode Island	-0.085	0.122	-0.7	0.485	-0.323	0.154
Idaho	-0.074	0.076	-0.98	0.329	-0.223	0.075
Mississippi	-0.061	0.080	-0.76	0.448	-0.217	0.096
Michigan	-0.047	0.083	-0.57	0.57	-0.209	0.115

Utah	-0.031	0.108	-0.29	0.771	-0.244	0.181
Connecticut	-0.029	0.128	-0.23	0.819	-0.281	0.222
Delaware	-0.024	0.102	-0.24	0.812	-0.224	0.175
Oregon	-0.024	0.088	-0.27	0.786	-0.198	0.149
Florida	-0.016	0.255	-0.06	0.951	-0.516	0.484
Texas	-0.006	0.111	-0.05	0.958	-0.224	0.212
Massachusetts	-0.005	0.148	-0.04	0.971	-0.295	0.284
Louisiana	0.009	0.077	0.11	0.909	-0.143	0.161
Nevada	0.011	0.093	0.12	0.904	-0.172	0.195
Georgia	0.023	0.107	0.21	0.833	-0.188	0.233
New York	0.027	0.114	0.24	0.814	-0.197	0.250
Nebraska	0.034	0.073	0.46	0.642	-0.109	0.177
Oklahoma	0.050	0.107	0.47	0.641	-0.160	0.260
New Jersey	0.072	0.115	0.63	0.53	-0.153	0.297
Wyoming	0.077	0.117	0.66	0.509	-0.152	0.307
Arizona	0.086	0.150	0.57	0.566	-0.208	0.381

The short-run estimates are mostly lower in the natural gas market than the electricity markets, with the exception of Maine which was discussed earlier. The overall precision of the estimates is also limited, which is shown by only ten states with statistically significant results. The natural gas market, like the commercial electricity market, had much greater variability in demand. Therefore, the limited precision is not surprising.

Table D.15: Regression results for long-run price elasticities for residential natural gas

Long Run Natural Gas

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Maine	-1.826	0.891	-2.05	0.041	-3.575	-0.078
Vermont	-0.577	0.189	-3.06	0.002	-0.947	-0.207
New Hampshire	-0.430	0.232	-1.86	0.064	-0.885	0.024
Virginia	-0.322	0.179	-1.8	0.072	-0.672	0.028
South Carolina	-0.299	0.248	-1.2	0.228	-0.787	0.188
Montana	-0.287	0.101	-2.83	0.005	-0.486	-0.088
New Mexico	-0.281	0.144	-1.96	0.05	-0.563	0.000
North Carolina	-0.279	0.212	-1.32	0.187	-0.695	0.136
West Virginia	-0.270	0.129	-2.1	0.036	-0.523	-0.018
Illinois	-0.243	0.100	-2.44	0.015	-0.438	-0.047
North Dakota	-0.230	0.087	-2.64	0.009	-0.402	-0.059
Washington	-0.214	0.147	-1.45	0.147	-0.503	0.075
Missouri	-0.174	0.081	-2.16	0.031	-0.332	-0.016
Kentucky	-0.171	0.073	-2.34	0.02	-0.315	-0.028
Kansas	-0.168	0.072	-2.34	0.019	-0.310	-0.027
Tennessee	-0.167	0.169	-0.99	0.323	-0.498	0.165
Indiana	-0.163	0.078	-2.08	0.037	-0.317	-0.009
Rhode Island	-0.163	0.234	-0.7	0.487	-0.622	0.296
Alabama	-0.159	0.090	-1.77	0.077	-0.336	0.017

South Dakota	-0.142	0.107	-1.33	0.183	-0.352	0.067
Arkansas	-0.141	0.075	-1.87	0.062	-0.289	0.007
Maryland	-0.134	0.136	-0.99	0.323	-0.400	0.132
Minnesota	-0.133	0.088	-1.5	0.134	-0.306	0.041
California	-0.132	0.166	-0.8	0.425	-0.458	0.193
Ohio	-0.132	0.081	-1.64	0.101	-0.291	0.026
Pennsylvania	-0.124	0.098	-1.27	0.205	-0.315	0.068
Colorado	-0.122	0.075	-1.63	0.104	-0.270	0.025
Iowa	-0.114	0.109	-1.04	0.296	-0.329	0.100
Wisconsin	-0.110	0.075	-1.46	0.145	-0.257	0.038
Idaho	-0.104	0.112	-0.94	0.35	-0.323	0.115
Mississippi	-0.079	0.110	-0.72	0.471	-0.295	0.136
Michigan	-0.075	0.131	-0.57	0.567	-0.333	0.182
Utah	-0.061	0.213	-0.29	0.776	-0.478	0.357
Connecticut	-0.042	0.184	-0.23	0.818	-0.402	0.318
Delaware	-0.036	0.153	-0.24	0.813	-0.337	0.264
Oregon	-0.028	0.104	-0.27	0.788	-0.232	0.176
Florida	-0.020	0.317	-0.06	0.951	-0.642	0.603
Massachusetts	-0.009	0.256	-0.04	0.971	-0.512	0.494
Texas	-0.008	0.159	-0.05	0.958	-0.320	0.303
Louisiana	0.011	0.093	0.11	0.909	-0.171	0.193
Nevada	0.021	0.175	0.12	0.905	-0.323	0.365
Georgia	0.022	0.105	0.21	0.834	-0.185	0.229
New York	0.029	0.124	0.24	0.812	-0.213	0.272
Nebraska	0.038	0.081	0.47	0.64	-0.121	0.197
Oklahoma	0.056	0.120	0.47	0.641	-0.179	0.291
New Jersey	0.082	0.129	0.63	0.528	-0.172	0.335
Wyoming	0.092	0.127	0.73	0.465	-0.156	0.341
Arizona	0.119	0.220	0.54	0.588	-0.312	0.550

Similar to other markets, the long-run estimates are generally larger than the short run estimates. The precision of these estimates is also limited, which is shown by the large standard errors and that only ten states have statistically significant estimates. The natural gas market also had much greater variation in prices and quantity during this period, which appears to affect the results at this level of aggregation. With the exception of Maine, the range of estimates is smaller than the electricity markets, which corresponds to the generally smaller (in absolute magnitude) values of the estimates when compared to the other markets.

We tested for first-order autocorrelation in the state-level residential natural gas model and found it does not appear to affect the error term. The estimate of ρ was -0.12 with a t-statistic of -1.75. The results indicate that autocorrelation does not affect consistency of estimates on the lagged demand term and that inference based on the existing standard errors is valid.

Utility-level results

Table D.16: Short run elasticity estimates for residential electricity at the utility level

Utility Number	region	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
182	ENC	-1.563	0.472	-3.31	0.001	-2.490	-0.637
208	ENC	-1.081	0.633	-1.71	0.088	-2.323	0.160
186	ENC	-1.061	0.521	-2.04	0.042	-2.082	-0.039
191	ENC	-0.697	0.275	-2.54	0.011	-1.237	-0.158
18	ENC	-0.584	0.279	-2.1	0.036	-1.13	-0.04
75	ENC	-0.480	0.498	-0.96	0.335	-1.46	0.50
134	ENC	-0.392	0.257	-1.53	0.127	-0.896	0.112
153	ENC	-0.314	0.238	-1.32	0.188	-0.781	0.154
35	ENC	-0.250	0.160	-1.57	0.118	-0.56	0.06
73	ENC	-0.243	0.135	-1.8	0.072	-0.51	0.02
177	ENC	-0.217	0.622	-0.35	0.728	-1.438	1.004
67	ENC	-0.167	0.245	-0.68	0.495	-0.65	0.31
41	ENC	-0.150	0.353	-0.43	0.671	-0.84	0.54
44	ENC	-0.137	0.291	-0.47	0.637	-0.71	0.43
17	ENC	-0.131	0.469	-0.28	0.78	-1.05	0.79
76	ENC	-0.105	0.337	-0.31	0.756	-0.77	0.56
38	ENC	-0.097	0.427	-0.23	0.82	-0.93	0.74
26	ENC	-0.091	0.359	-0.25	0.8	-0.80	0.61
96	ENC	-0.082	0.331	-0.25	0.803	-0.73	0.57
105	ENC	-0.070	0.175	-0.4	0.689	-0.41	0.27
28	ENC	-0.045	0.399	-0.11	0.909	-0.83	0.74
33	ENC	-0.033	0.320	-0.1	0.917	-0.66	0.59
206	ENC	-0.004	0.517	-0.01	0.994	-1.019	1.011
133	ENC	0.024	0.490	0.05	0.96	-0.936	0.985
207	ENC	0.109	0.355	0.31	0.758	-0.587	0.806
129	ENC	0.211	0.563	0.37	0.708	-0.894	1.315
130	ENC	0.952	1.475	0.65	0.519	-1.941	3.845
103	ESC	-1.514	0.410	-3.69	0	-2.32	-0.71
113	ESC	-1.222	0.397	-3.08	0.002	-2.00	-0.44
47	ESC	-1.126	0.675	-1.67	0.096	-2.45	0.20
120	ESC	-1.064	0.625	-1.7	0.089	-2.291	0.163
30	ESC	-1.046	0.689	-1.52	0.129	-2.40	0.31
198	ESC	-0.958	0.414	-2.32	0.021	-1.770	-0.147
40	ESC	-0.884	0.857	-1.03	0.302	-2.56	0.80
110	ESC	-0.766	0.389	-1.97	0.049	-1.53	0.00
92	ESC	-0.680	0.598	-1.14	0.256	-1.85	0.49
86	ESC	-0.528	0.394	-1.34	0.181	-1.30	0.25
179	ESC	-0.499	0.230	-2.17	0.03	-0.950	-0.048
69	ESC	-0.486	0.592	-0.82	0.411	-1.65	0.67
98	ESC	-0.439	0.835	-0.53	0.599	-2.08	1.20
193	ESC	-0.299	0.386	-0.77	0.439	-1.055	0.458
172	ESC	-0.297	0.276	-1.07	0.283	-0.839	0.245
1	ESC	-0.200	0.522	-0.38	0.701	-1.22	0.82
23	ESC	-0.192	0.521	-0.37	0.713	-1.21	0.83

107	ESC	-0.178	0.548	-0.32	0.746	-1.25	0.90
93	ESC	-0.088	0.226	-0.39	0.699	-0.53	0.36
210	ESC	-0.018	0.801	-0.02	0.982	-1.589	1.552
57	ESC	0.148	0.745	0.2	0.843	-1.31	1.61
91	ESC	0.317	0.338	0.94	0.348	-0.35	0.98
112	ESC	0.402	0.612	0.66	0.511	-0.80	1.60
200	ESC	1.389	0.305	4.55	0	0.790	1.987
211	M	-1.206	0.394	-3.06	0.002	-1.979	-0.433
94	M	-1.084	0.629	-1.72	0.085	-2.32	0.15
140	M	-0.980	0.401	-2.45	0.015	-1.767	-0.194
155	M	-0.696	0.248	-2.81	0.005	-1.183	-0.210
171	M	-0.694	0.586	-1.18	0.237	-1.844	0.456
184	M	-0.663	0.607	-1.09	0.274	-1.854	0.527
164	M	-0.547	0.403	-1.36	0.174	-1.338	0.243
151	M	-0.368	1.027	-0.36	0.72	-2.382	1.647
53	M	-0.325	0.725	-0.45	0.655	-1.75	1.10
122	M	-0.262	0.075	-3.51	0	-0.409	-0.116
152	M	-0.260	0.396	-0.66	0.512	-1.036	0.516
32	M	-0.233	0.649	-0.36	0.72	-1.51	1.04
5	M	-0.221	0.372	-0.59	0.552	-0.95	0.51
118	M	-0.096	0.187	-0.51	0.61	-0.463	0.272
196	M	-0.061	0.305	-0.2	0.842	-0.660	0.538
25	M	-0.014	0.253	-0.06	0.955	-0.51	0.48
104	M	-0.001	0.283	0	0.996	-0.56	0.55
71	M	0.467	0.298	1.57	0.117	-0.12	1.05
202	MA	-0.800	0.429	-1.87	0.062	-1.641	0.041
109	MA	-0.792	0.625	-1.27	0.205	-2.02	0.43
37	MA	-0.712	0.600	-1.19	0.235	-1.89	0.46
100	MA	-0.639	0.418	-1.53	0.126	-1.46	0.18
160	MA	-0.417	0.383	-1.09	0.277	-1.169	0.336
125	MA	-0.345	0.321	-1.07	0.284	-0.975	0.286
147	MA	-0.341	0.284	-1.2	0.23	-0.897	0.216
145	MA	-0.308	0.477	-0.65	0.518	-1.244	0.627
213	MA	-0.230	0.301	-0.76	0.446	-0.821	0.361
85	MA	-0.177	0.364	-0.49	0.626	-0.89	0.54
157	MA	-0.117	0.475	-0.25	0.805	-1.050	0.815
49	MA	-0.089	0.240	-0.37	0.711	-0.56	0.38
161	MA	-0.003	0.492	-0.01	0.996	-0.967	0.962
16	MA	0.077	0.478	0.16	0.872	-0.86	1.02
137	MA	0.099	0.329	0.3	0.763	-0.546	0.744
146	MA	0.125	0.146	0.86	0.39	-0.161	0.412
7	MA	0.171	0.180	0.95	0.341	-0.18	0.52
144	MA	0.302	0.323	0.94	0.35	-0.332	0.936
126	MA	0.350	0.296	1.18	0.238	-0.231	0.932
20	NE	-0.722	0.421	-1.72	0.086	-1.55	0.10
119	NE	-0.596	0.569	-1.05	0.296	-1.713	0.521
65	NE	-0.546	0.149	-3.65	0	-0.84	-0.25
22	NE	-0.391	0.278	-1.41	0.159	-0.94	0.15
123	NE	-0.360	0.229	-1.57	0.117	-0.809	0.090
194	NE	-0.197	0.535	-0.37	0.712	-1.246	0.851

34	NE	-0.196	0.212	-0.93	0.355	-0.61	0.22
36	NE	-0.154	0.348	-0.44	0.659	-0.84	0.53
14	NE	-0.091	0.254	-0.36	0.721	-0.59	0.41
46	NE	-0.019	0.272	-0.07	0.946	-0.55	0.52
4	NE	0.063	0.416	0.15	0.88	-0.75	0.88
154	NE	0.072	0.723	0.1	0.92	-1.346	1.491
10	NE	0.191	0.333	0.57	0.566	-0.46	0.84
204	NE	0.197	0.400	0.49	0.622	-0.587	0.981
106	NE	0.849	0.908	0.93	0.35	-0.93	2.63
139	PC	-1.215	0.094	-12.96	0	-1.399	-1.031
24	PC	-0.961	0.035	-27.6	0	-1.03	-0.89
2	PC	-0.770	0.144	-5.35	0	-1.05	-0.49
173	PC	-0.595	0.568	-1.05	0.295	-1.711	0.520
158	PC	-0.488	0.486	-1	0.315	-1.440	0.465
101	PC	-0.471	0.269	-1.75	0.081	-1.00	0.06
64	PC	-0.444	0.324	-1.37	0.171	-1.08	0.19
166	PC	-0.430	0.366	-1.18	0.24	-1.147	0.287
176	PC	-0.279	0.365	-0.76	0.444	-0.995	0.437
39	PC	-0.219	0.228	-0.96	0.336	-0.67	0.23
188	PC	-0.156	0.379	-0.41	0.682	-0.899	0.588
27	PC	-0.119	0.431	-0.28	0.783	-0.96	0.73
142	PC	-0.119	0.335	-0.35	0.724	-0.776	0.539
170	PC	0.014	0.377	0.04	0.971	-0.726	0.754
74	PC	0.068	0.303	0.23	0.822	-0.53	0.66
163	PC	0.144	0.511	0.28	0.778	-0.859	1.147
201	PC	0.279	0.552	0.5	0.614	-0.805	1.362
11	PC	0.324	0.181	1.79	0.073	-0.03	0.68
159	PC	0.404	0.548	0.74	0.461	-0.671	1.479
115	PC	0.475	0.421	1.13	0.26	-0.35	1.30
148	PC	0.670	0.402	1.66	0.096	-0.120	1.459
52	PC	0.756	0.515	1.47	0.142	-0.25	1.77
197	SA	-1.477	0.743	-1.99	0.047	-2.935	-0.020
178	SA	-1.434	0.542	-2.65	0.008	-2.497	-0.371
29	SA	-1.299	0.474	-2.74	0.006	-2.23	-0.37
63	SA	-1.232	0.725	-1.7	0.09	-2.65	0.19
199	SA	-1.150	0.635	-1.81	0.07	-2.396	0.096
187	SA	-1.087	0.525	-2.07	0.039	-2.118	-0.056
95	SA	-1.073	0.621	-1.73	0.085	-2.29	0.15
31	SA	-1.038	0.238	-4.36	0	-1.50	-0.57
97	SA	-1.032	0.621	-1.66	0.097	-2.25	0.19
127	SA	-0.890	0.660	-1.35	0.178	-2.186	0.405
169	SA	-0.884	0.366	-2.42	0.016	-1.602	-0.167
84	SA	-0.878	0.566	-1.55	0.121	-1.99	0.23
168	SA	-0.854	0.290	-2.94	0.003	-1.423	-0.284
189	SA	-0.827	0.607	-1.36	0.173	-2.018	0.363
83	SA	-0.814	0.306	-2.66	0.008	-1.41	-0.21
15	SA	-0.734	0.583	-1.26	0.208	-1.88	0.41
128	SA	-0.686	0.297	-2.31	0.021	-1.270	-0.103
60	SA	-0.678	0.368	-1.84	0.066	-1.40	0.05
48	SA	-0.542	0.673	-0.8	0.421	-1.86	0.78

72	SA	-0.540	0.504	-1.07	0.284	-1.53	0.45
116	SA	-0.472	0.298	-1.58	0.113	-1.06	0.11
190	SA	-0.458	0.501	-0.91	0.361	-1.441	0.525
62	SA	-0.447	0.320	-1.4	0.162	-1.07	0.18
174	SA	-0.438	0.541	-0.81	0.418	-1.498	0.623
66	SA	-0.304	0.334	-0.91	0.363	-0.96	0.35
58	SA	-0.299	0.373	-0.8	0.422	-1.03	0.43
56	SA	-0.272	0.366	-0.74	0.458	-0.99	0.45
82	SA	-0.243	0.354	-0.69	0.492	-0.94	0.45
54	SA	-0.195	0.388	-0.5	0.614	-0.96	0.57
141	SA	-0.164	0.102	-1.61	0.108	-0.363	0.036
214	SA	-0.160	0.388	-0.41	0.681	-0.921	0.602
12	SA	-0.129	0.212	-0.61	0.544	-0.55	0.29
9	SA	-0.124	0.426	-0.29	0.772	-0.96	0.71
175	SA	-0.123	0.273	-0.45	0.651	-0.658	0.412
149	SA	-0.004	0.431	-0.01	0.993	-0.850	0.842
209	SA	0.004	0.473	0.01	0.994	-0.925	0.933
43	SA	0.038	0.405	0.09	0.925	-0.76	0.83
59	SA	0.041	0.448	0.09	0.928	-0.84	0.92
205	SA	0.234	0.383	0.61	0.541	-0.517	0.986
42	SA	0.241	1.088	0.22	0.825	-1.89	2.38
162	SA	0.488	0.374	1.31	0.192	-0.245	1.221
78	WNC	-1.746	1.057	-1.65	0.099	-3.82	0.33
192	WNC	-1.127	0.243	-4.64	0	-1.604	-0.651
131	WNC	-0.654	0.332	-1.97	0.049	-1.307	-0.002
88	WNC	-0.622	0.261	-2.39	0.017	-1.13	-0.11
90	WNC	-0.615	0.364	-1.69	0.091	-1.33	0.10
150	WNC	-0.552	0.188	-2.94	0.003	-0.920	-0.184
114	WNC	-0.495	0.749	-0.66	0.509	-1.96	0.97
132	WNC	-0.476	0.447	-1.06	0.287	-1.353	0.401
77	WNC	-0.471	0.336	-1.4	0.162	-1.13	0.19
183	WNC	-0.463	0.115	-4.02	0	-0.688	-0.237
111	WNC	-0.440	0.303	-1.45	0.146	-1.03	0.15
136	WNC	-0.425	0.373	-1.14	0.255	-1.157	0.308
89	WNC	-0.352	0.221	-1.59	0.111	-0.79	0.08
79	WNC	-0.200	0.522	-0.38	0.701	-1.22	0.82
80	WNC	-0.200	0.522	-0.38	0.701	-1.22	0.82
81	WNC	-0.200	0.522	-0.38	0.701	-1.22	0.82
3	WNC	-0.190	0.411	-0.46	0.643	-1.00	0.62
108	WNC	-0.153	0.427	-0.36	0.719	-0.99	0.68
87	WNC	-0.124	0.404	-0.31	0.758	-0.92	0.67
195	WNC	-0.070	0.455	-0.15	0.878	-0.962	0.822
138	WNC	-0.052	0.419	-0.13	0.901	-0.874	0.769
185	WNC	0.041	0.406	0.1	0.921	-0.757	0.838
121	WNC	0.179	0.268	0.67	0.504	-0.346	0.704
99	WNC	0.489	0.717	0.68	0.496	-0.92	1.90
212	WNC	1.109	0.779	1.42	0.155	-0.420	2.638
51	WNC	1.404	0.422	3.32	0.001	0.58	2.23
135	WSC	-1.226	0.591	-2.07	0.038	-2.385	-0.067
6	WSC	-0.917	0.283	-3.24	0.001	-1.47	-0.36

215	WSC	-0.632	0.354	-1.78	0.075	-1.326	0.063
102	WSC	-0.615	0.344	-1.79	0.074	-1.29	0.06
124	WSC	-0.613	0.254	-2.42	0.016	-1.111	-0.115
13	WSC	-0.517	0.726	-0.71	0.476	-1.94	0.91
55	WSC	-0.485	0.335	-1.45	0.148	-1.14	0.17
167	WSC	-0.484	0.437	-1.11	0.268	-1.340	0.373
45	WSC	-0.464	0.265	-1.75	0.08	-0.98	0.06
19	WSC	-0.450	0.448	-1	0.315	-1.33	0.43
181	WSC	-0.318	0.331	-0.96	0.338	-0.968	0.332
156	WSC	-0.286	0.440	-0.65	0.516	-1.150	0.578
165	WSC	-0.272	0.404	-0.67	0.502	-1.065	0.522
21	WSC	-0.154	0.292	-0.53	0.597	-0.73	0.42
68	WSC	-0.108	0.234	-0.46	0.646	-0.57	0.35
70	WSC	-0.091	0.508	-0.18	0.858	-1.09	0.91
180	WSC	0.023	0.587	0.04	0.969	-1.129	1.174
8	WSC	0.066	0.406	0.16	0.872	-0.73	0.86
203	WSC	0.447	0.205	2.18	0.03	0.044	0.851
61	WSC	0.452	0.317	1.43	0.154	-0.17	1.07
50	WSC	0.486	0.427	1.14	0.255	-0.35	1.32
143	WSC	0.614	0.440	1.39	0.163	-0.250	1.477

The utility results also have a wide range of price elasticity estimates. The minimum value is –1.75 and the maximum is 1.40. In general, the estimates are representative of the results from the state-level analysis in residential electricity. Most estimates are negative and in the inelastic range. Some are positive in each region. Overall, these results suffer from a lack of precision also. Only about 17% of the utilities in the sample were statistically significant. Some of this variation in the estimates may be explained by the large differences in the size of utilities.

We tested for first-order autocorrelation in the error term and the results indicate it may be present. The estimate of ρ for the utility-level model was -0.32 with a t-statistic of -3.27. The results suggest first-order autocorrelation in the error term and we, therefore, ran the model to account for an AR(1) structure in the error term.

Results from Energy Use Trend Analysis

The trend analysis fits a linear trend to the variable of interest. Many of the trends in the data were linear and the model fit well. In some cases, particularly the natural gas market, the trends were not linear and the model had a poorer fit.

This section will now display the trend analysis results first for the region level and then at the state level.

Regional-Level Results

The model has the form:

$$\ln y_{it} = \alpha + \text{year}_t\,\beta + \text{region}_i\,\delta_i + (\text{region}_i \times \text{year}_t)\,\beta_i + \varepsilon_{it}$$

The model includes an indicator variable for region and an interaction term between region and year. These terms allow the slope of the trend and y-intercept to vary freely for each region.

Residential Electricity

Table D.17: Regional trends in residential electricity energy intensity

	Coef	Std. Err.	t	P>|t|	95% Conf	Interval
South Atlantic	1.94%	0.08%	25.7	0.0	1.79%	2.09%
East South Central	1.79%	0.11%	16.8	0.0	1.59%	2.00%
West South Central	1.59%	0.11%	14.9	0.0	1.38%	1.80%
West North Central	1.45%	0.08%	18.0	0.0	1.29%	1.61%
East North Central	1.40%	0.10%	14.6	0.0	1.21%	1.58%
Mid Atlantic	1.33%	0.12%	10.8	0.0	1.09%	1.57%
New England	0.91%	0.09%	10.4	0.0	0.73%	1.08%
Mountain	0.80%	0.08%	10.6	0.0	0.65%	0.95%
Pacific Coast	-0.12%	0.12%	-1.0	0.3	-0.36%	0.12%

Intensity is measured as quantity of residential electricity per capita. The table shows per capita electricity use is growing fastest in the South Atlantic and Central regions. Growth in per capita electricity use is negligible in the Pacific Coast region.

Table D.18: Regional trends in residential electricity expenditures

	Coef	Std. Err.	t	P>|t|	95% Conf	Interval
New England	0.717%	0.111%	6.49	0	0.500%	0.934%
Pacific Coast	0.680%	0.156%	4.35	0	0.373%	0.987%
East South Central	0.624%	0.135%	4.61	0	0.358%	0.890%
South Atlantic	0.621%	0.096%	6.48	0	0.433%	0.809%
West South Central	0.518%	0.135%	3.83	0	0.253%	0.784%
Mid Atlantic	0.316%	0.156%	2.02	0.04	0.009%	0.623%
West North Central	0.143%	0.102%	1.4	0.16	-0.058%	0.344%
East North Central	0.122%	0.121%	1.01	0.32	-0.116%	0.359%
Mountain	0.008%	0.096%	0.09	0.93	-0.180%	0.196%

Expenditures are growing fastest in the New England and Pacific Coast regions. Growth in expenditures is negligible in the Mountain region. Overall, the growth rates are all less than 1%.

Table D.19: Regional trends in residential electricity expenditures as a share of income

	Coef	Std. Err.	t	P>|t|	95% Conf	Interval
Mid Atlantic	-1.99%	0.17%	-12.08	0	-2.32%	-1.67%
West North Central	-1.98%	0.11%	-18.32	0	-2.19%	-1.77%
East North Central	-1.90%	0.13%	-14.83	0	-2.15%	-1.65%
Mountain	-1.83%	0.10%	-18.07	0	-2.03%	-1.63%
New England	-1.82%	0.12%	-15.58	0	-2.05%	-1.59%
East South Central	-1.80%	0.14%	-12.57	0	-2.08%	-1.52%
South Atlantic	-1.71%	0.10%	-16.9	0	-1.91%	-1.51%
West South Central	-1.46%	0.14%	-10.24	0	-1.74%	-1.18%
Pacific Coast	-1.19%	0.17%	-7.21	0	-1.51%	-0.87%

The trends in expenditures as a share of income show that income growth is faster than the increase in energy expenditures. Therefore, energy expenditures as a portion of household budgets is generally decreasing. The regional differences in the rate of decrease vary by about 1%. Expenditures as a share of income are declining fastest in the Mid Atlantic at about 2%. Decline is slowest in the Pacific Coast region at approximately 1%.

Commercial Electricity

Table D.20: Regional trends in commercial energy intensity

Regional commercial energy intensity trends R-square = 0.57

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
New England	2.32%	0.20%	11.42	0	1.92%	2.72%
West North Central	2.18%	0.30%	7.15	0	1.58%	2.77%
South Atlantic	1.97%	0.20%	9.9	0	1.58%	2.36%
Mid Atlantic	1.78%	0.25%	7.01	0	1.28%	2.28%
East North Central	1.49%	0.20%	7.58	0	1.10%	1.87%
Mountain	1.48%	0.29%	5.19	0	0.92%	2.04%
West South Central	0.96%	0.25%	3.81	0	0.47%	1.45%
East South Central	0.94%	0.46%	2.04	0.041	0.04%	1.84%
Pacific Coast	0.25%	0.32%	0.8	0.425	-0.37%	0.88%

Intensity is measured as quantity of commercial electricity per unit of commercial floorspace. The results show statistically significant differences in the annual growth rates. The Pacific Coast rate is near zero, whereas the annual growth rates are over 2% in New England and the West North Central. All the trend estimates are statistically significant, except the Pacific Coast region. However, the model fit is only moderate, which is shown by the adjusted R-squared of 0.57.

Natural Gas

Table D.21: Regional energy intensity trends for residential natural gas

Regional Trend in Natural Gas Energy Intensity					R-squared	0.4302
	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	1.09%	0.60%	1.84	0.067	-0.08%	2.26%
Mid Atlantic	0.45%	0.17%	2.7	0.007	0.12%	0.78%
New England	0.15%	1.08%	0.14	0.892	-1.97%	2.26%
Mountain	-0.41%	0.39%	-1.06	0.288	-1.17%	0.35%
South Atlantic	-0.45%	0.71%	-0.63	0.529	-1.85%	0.95%
East North Central	-0.47%	0.19%	-2.41	0.016	-0.85%	-0.09%
East South Central	-0.57%	0.31%	-1.87	0.062	-1.17%	0.03%
West North Central	-0.60%	0.23%	-2.66	0.008	-1.05%	-0.16%
West South Central	-2.05%	0.28%	-7.41	0	-2.60%	-1.51%

In this case, we measured energy intensity as the quantity of natural gas consumed per capita. The results show much different regional trends. Residential natural gas energy intensity is increasing in the Pacific Coast, Mid Atlantic, and New England regions. The trend is a slight decline in the South Atlantic and Central regions, except for the West South Central where intensity is declining over 2% per year.

The model fit is only fair in this case. The r-squared for this model is 0.43. The natural gas trends generally have two peaks, which is why the linear fit is limited.

Table D.22: Regional trends in natural gas energy expenditures

Regional Trend in Natural Gas Energy Expenditures					R-squared	0.3345
	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	1.01%	0.45%	2.25	0.025	0.13%	1.89%
Mid Atlantic	0.75%	0.20%	3.85	0	0.37%	1.14%
East South Central	0.70%	0.34%	2.06	0.04	0.03%	1.36%
South Atlantic	0.47%	0.64%	0.74	0.458	-0.78%	1.73%
West North Central	0.14%	0.25%	0.55	0.579	-0.36%	0.64%
New England	-0.04%	1.08%	-0.04	0.971	-2.16%	2.08%
Mountain	-0.15%	0.28%	-0.53	0.595	-0.71%	0.41%
East North Central	-0.15%	0.23%	-0.65	0.517	-0.61%	0.31%
West South Central	-0.56%	0.29%	-1.93	0.054	-1.14%	0.01%

The trend is rising expenditures in the Pacific Coast, Mid Atlantic, East South Central, South Atlantic, and West North Central regions. Expenditures are falling in the New England, Mountain, East North Central, and West South Central regions. For most regions, the trend is near or less than 0.5% in absolute magnitude. Therefore, the estimates show that expenditures are relatively stable for most people.

The model fit is marginal in this case. Natural gas prices had several spikes and dropoffs, which is a nonlinear pattern. The expenditure data follow the price trend closely. Therefore, the linear fit is marginal for this variable.

Table D.23: Annual trends for natural gas expenditures as a share of income

R-squared 0.3865

Regional Trend in Natural Gas Energy Expenditures as Income Share

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.84%	0.40%	-2.09	0.036	-1.62%	-0.05%
Mid Atlantic	-1.56%	0.21%	-7.44	0	-1.97%	-1.15%
East South Central	-1.74%	0.34%	-5.06	0	-2.42%	-1.07%
South Atlantic	-1.85%	0.65%	-2.86	0.004	-3.11%	-0.58%
West North Central	-1.98%	0.24%	-8.4	0	-2.45%	-1.52%
Mountain	-1.99%	0.28%	-7.16	0	-2.53%	-1.44%
East North Central	-2.17%	0.22%	-9.84	0	-2.60%	-1.74%
New England	-2.49%	1.00%	-2.48	0.013	-4.45%	-0.52%
West South Central	-2.53%	0.32%	-7.96	0	-3.15%	-1.90%

The results show that expenditures as a share of income are falling in all regions. The most rapid decline is in the West South Central. The Pacific Coast trend has the most moderate decline. Again, the model fit is only marginal for the reasons stated above.

State-Level Results

The model has the form:

$$\ln y_{it} = \alpha + \text{year}_t\, \beta + \text{state}_i\, \delta_i + (\text{state}_i \times \text{year}_t)\, \beta_i + \varepsilon_{it}$$

The model includes an indicator variable for each state and an interaction term between state and year. These terms allow the slope of the trend and y-intercept to vary freely for each state.

Residential Electricity

Table D.24: Residential electricity energy intensity

Residential Energy Intensity

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
West Virginia	2.51%	0.05%	49.2	0	2.41%	2.61%
Delaware	2.49%	0.23%	10.81	0	2.04%	2.95%
Kentucky	2.43%	0.08%	29.32	0	2.26%	2.59%
Maryland	2.42%	0.13%	18.68	0	2.17%	2.68%
Mississippi	2.23%	0.08%	26.32	0	2.06%	2.39%
Alabama	2.18%	0.09%	23.46	0	2.00%	2.36%
South Carolina	2.16%	0.07%	29.65	0	2.01%	2.30%
Louisiana	2.14%	0.07%	32.43	0	2.01%	2.27%
Missouri	2.10%	0.11%	19.84	0	1.89%	2.31%
Kansas	1.97%	0.13%	14.98	0	1.71%	2.22%
Georgia	1.95%	0.08%	24.76	0	1.79%	2.10%
New Mexico	1.88%	0.08%	23.37	0	1.72%	2.04%
Virginia	1.85%	0.07%	28.03	0	1.72%	1.97%
Pennsylvania	1.76%	0.05%	36.67	0	1.66%	1.85%
North Dakota	1.76%	0.12%	14.68	0	1.52%	1.99%
North Carolina	1.71%	0.06%	27	0	1.59%	1.84%
Wyoming	1.71%	0.19%	8.93	0	1.33%	2.08%
Texas	1.64%	0.10%	17.04	0	1.45%	1.83%
Florida	1.64%	0.08%	20.98	0	1.49%	1.79%
Massachusetts	1.63%	0.06%	25.06	0	1.50%	1.75%
Arkansas	1.62%	0.17%	9.55	0	1.29%	1.96%
Ohio	1.62%	0.04%	38.3	0	1.54%	1.70%
Indiana	1.62%	0.05%	35.62	0	1.53%	1.71%
Nebraska	1.61%	0.10%	15.85	0	1.41%	1.81%
Oklahoma	1.60%	0.11%	14.27	0	1.38%	1.82%
New Jersey	1.59%	0.06%	27.69	0	1.48%	1.71%
Arizona	1.52%	0.07%	22.08	0	1.39%	1.66%
Rhode Island	1.49%	0.05%	31.61	0	1.40%	1.58%
New York	1.42%	0.05%	30.3	0	1.33%	1.51%
Michigan	1.40%	0.07%	19.1	0	1.25%	1.54%
Colorado	1.37%	0.21%	6.44	0	0.95%	1.79%
Connecticut	1.37%	0.06%	24.85	0	1.26%	1.48%
Minnesota	1.34%	0.08%	16.31	0	1.18%	1.51%
Utah	1.22%	0.08%	14.57	0	1.05%	1.38%
Illinois	1.19%	0.10%	11.66	0	0.99%	1.39%
Wisconsin	1.18%	0.08%	14.22	0	1.02%	1.34%
South Dakota	1.16%	0.11%	10.4	0	0.94%	1.37%
Iowa	1.06%	0.08%	12.6	0	0.90%	1.23%
Montana	0.79%	0.14%	5.51	0	0.51%	1.07%
Tennessee	0.69%	0.12%	5.66	0	0.45%	0.93%

New Hampshire	0.61%	0.10%	6.18	0	0.42%	0.80%
Maine	0.60%	0.12%	4.82	0	0.35%	0.84%
Vermont	0.32%	0.17%	1.92	0.055	-0.01%	0.65%
California	0.28%	0.07%	3.99	0	0.14%	0.42%
Nevada	0.07%	0.12%	0.59	0.554	-0.16%	0.30%
Oregon	0.00%	0.08%	0.01	0.994	-0.16%	0.16%
Idaho	-0.01%	0.11%	-0.11	0.915	-0.23%	0.20%
Washington	-0.57%	0.16%	-3.48	0.001	-0.89%	-0.25%

The results show that per capita residential electricity use is growing quickly in southern states. All of the states with a growth rate over 2% are in the South Atlantic and East South Central regions. The growth rate is considerably smaller (less than 0.5%) in Vermont, California, Nevada, Oregon, Idaho, and Washington. Notably, Oregon, Idaho, and Washington have zero growth or declining per capita use.

Table D.25: Trends in expenditures on residential electricity as a share of income

Residential Electricity Income Share	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Utah	-2.79%	0.34%	-8.1	0	-3.46%	-2.11%
New Jersey	-2.47%	0.17%	-14.35	0	-2.80%	-2.13%
Tennessee	-2.33%	0.12%	-19.39	0	-2.57%	-2.10%
Minnesota	-2.27%	0.21%	-10.71	0	-2.69%	-1.85%
South Dakota	-2.22%	0.34%	-6.52	0	-2.89%	-1.55%
New Hampshire	-2.17%	0.17%	-12.68	0	-2.51%	-1.84%
Illinois	-2.14%	0.40%	-5.38	0	-2.92%	-1.36%
Massachusetts	-2.09%	0.19%	-11.15	0	-2.46%	-1.72%
Wisconsin	-2.01%	0.25%	-8.03	0	-2.50%	-1.52%
Virginia	-1.98%	0.11%	-18.49	0	-2.20%	-1.77%
Colorado	-1.98%	0.41%	-4.88	0	-2.77%	-1.18%
Nevada	-1.97%	0.28%	-7.1	0	-2.52%	-1.43%
Arkansas	-1.96%	0.19%	-10.06	0	-2.34%	-1.58%
Iowa	-1.93%	0.25%	-7.85	0	-2.41%	-1.44%
Indiana	-1.92%	0.22%	-8.78	0	-2.35%	-1.49%
Delaware	-1.92%	0.12%	-16.57	0	-2.15%	-1.69%
Florida	-1.86%	0.18%	-10.39	0	-2.21%	-1.51%
Rhode Island	-1.84%	0.17%	-10.55	0	-2.19%	-1.50%
North Dakota	-1.81%	0.30%	-5.99	0	-2.40%	-1.21%
Arizona	-1.78%	0.19%	-9.49	0	-2.14%	-1.41%
Nebraska	-1.76%	0.21%	-8.21	0	-2.18%	-1.34%
Michigan	-1.75%	0.09%	-20.16	0	-1.92%	-1.58%
Connecticut	-1.73%	0.24%	-7.33	0	-2.19%	-1.26%
Idaho	-1.70%	0.31%	-5.46	0	-2.31%	-1.09%
Oregon	-1.62%	0.17%	-9.37	0	-1.96%	-1.28%

Kentucky	-1.61%	0.31%	-5.21	0	-2.21%	-1.00%
Missouri	-1.58%	0.21%	-7.69	0	-1.99%	-1.18%
North Carolina	-1.58%	0.17%	-9.48	0	-1.90%	-1.25%
Alabama	-1.55%	0.17%	-8.97	0	-1.89%	-1.21%
Vermont	-1.50%	0.17%	-8.81	0	-1.83%	-1.16%
New Mexico	-1.49%	0.27%	-5.59	0	-2.02%	-0.97%
Ohio	-1.49%	0.19%	-7.87	0	-1.86%	-1.12%
Maryland	-1.42%	0.20%	-7.01	0	-1.82%	-1.02%
Georgia	-1.41%	0.12%	-12.09	0	-1.64%	-1.18%
Kansas	-1.38%	0.35%	-3.98	0	-2.05%	-0.70%
Oklahoma	-1.35%	0.26%	-5.15	0	-1.86%	-0.84%
Pennsylvania	-1.33%	0.16%	-8.22	0	-1.65%	-1.01%
New York	-1.33%	0.14%	-9.74	0	-1.59%	-1.06%
Mississippi	-1.33%	0.15%	-8.7	0	-1.62%	-1.03%
South Carolina	-1.29%	0.18%	-7.26	0	-1.64%	-0.94%
Texas	-1.29%	0.25%	-5.22	0	-1.77%	-0.80%
West Virginia	-1.12%	0.18%	-6.41	0	-1.47%	-0.78%
Washington	-1.10%	0.48%	-2.27	0.023	-2.04%	-0.15%
Maine	-1.04%	0.25%	-4.12	0	-1.53%	-0.54%
California	-0.73%	0.19%	-3.86	0	-1.10%	-0.36%
Louisiana	-0.59%	0.39%	-1.51	0.131	-1.36%	0.18%
Wyoming	-0.33%	0.51%	-0.65	0.517	-1.34%	0.67%
Montana	-0.27%	0.23%	-1.14	0.255	-0.73%	0.19%

The trends are declining in all states but the rates are considerably different. Nine states are declining at 2% per year or more. Four states are declining slower than 0.75%. There is a relatively even distribution of states between these points.

Commercial Electricity

We only estimated trends for commercial electricity energy intensity. We measure energy intensity for this variable is the amount of commercial electricity used per unit of commercial floorspace.

Table D.26: Estimates of the annual trend in commercial energy intensity

	Annual Trends - Commercial Energy Intensity (electricity / sq ft flooring)					
	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
New Hampshire	4.41%	0.21%	20.97	0	3.99%	4.82%
North Dakota	3.60%	0.34%	10.63	0	2.93%	4.26%
Wyoming	3.41%	0.45%	7.55	0	2.52%	4.29%
South Dakota	3.19%	0.18%	17.49	0	2.84%	3.55%
Vermont	2.89%	0.17%	16.94	0	2.55%	3.22%
North Carolina	2.61%	0.08%	32.58	0	2.45%	2.77%
Georgia	2.47%	0.24%	10.1	0	1.99%	2.95%
Maine	2.45%	0.18%	13.65	0	2.10%	2.81%

Alabama	2.40%	0.29%	8.43	0	1.85%	2.96%
Delaware	2.35%	0.21%	11.27	0	1.94%	2.76%
Maryland	2.34%	0.69%	3.41	0.001	0.99%	3.68%
Mississippi	2.32%	0.27%	8.75	0	1.80%	2.84%
Michigan	2.24%	0.25%	9.03	0	1.76%	2.73%
Missouri	2.11%	0.11%	18.8	0	1.89%	2.33%
West Virginia	2.06%	0.11%	19.46	0	1.85%	2.27%
New Mexico	2.04%	0.18%	11.63	0	1.69%	2.38%
Nebraska	2.01%	0.17%	12.11	0	1.68%	2.34%
Utah	1.99%	0.18%	11.21	0	1.64%	2.33%
New Jersey	1.95%	0.11%	18.44	0	1.74%	2.16%
Pennsylvania	1.81%	0.07%	25.32	0	1.67%	1.95%
Minnesota	1.70%	0.10%	17.38	0	1.51%	1.89%
Indiana	1.63%	0.12%	13.33	0	1.39%	1.87%
Rhode Island	1.62%	0.11%	14.08	0	1.39%	1.84%
Ohio	1.59%	0.14%	11.42	0	1.31%	1.86%
New York	1.58%	0.07%	21.73	0	1.44%	1.72%
Colorado	1.57%	0.26%	6.02	0	1.06%	2.08%
Montana	1.55%	0.54%	2.86	0.004	0.49%	2.61%
Florida	1.53%	0.09%	16.53	0	1.35%	1.72%
Kansas	1.41%	0.07%	19.97	0	1.28%	1.55%
Arkansas	1.38%	0.15%	9.41	0	1.09%	1.66%
Wisconsin	1.35%	0.10%	13.99	0	1.16%	1.54%
Kentucky	1.31%	0.07%	17.86	0	1.17%	1.45%
Texas	1.30%	0.09%	15.27	0	1.13%	1.47%
Connecticut	1.29%	0.09%	15	0	1.12%	1.46%
Massachusetts	1.26%	0.08%	15.03	0	1.10%	1.43%
Virginia	1.22%	0.07%	17.12	0	1.08%	1.36%
Iowa	1.21%	0.14%	8.48	0	0.93%	1.48%
South Carolina	1.18%	0.14%	8.62	0	0.91%	1.45%
Washington	0.86%	0.28%	3.06	0.002	0.31%	1.42%
Oklahoma	0.69%	0.17%	3.97	0	0.35%	1.03%
Arizona	0.64%	0.18%	3.58	0	0.29%	0.99%
Illinois	0.63%	0.14%	4.59	0	0.36%	0.90%
Oregon	0.56%	0.22%	2.59	0.01	0.14%	0.99%
Idaho	0.47%	0.18%	2.61	0.009	0.12%	0.83%
Louisiana	0.47%	0.08%	5.54	0	0.30%	0.64%
Nevada	0.20%	0.61%	0.34	0.737	-0.98%	1.39%
California	-0.66%	0.10%	-6.63	0	-0.86%	-0.47%
Tennessee	-2.27%	1.71%	-1.33	0.185	-5.64%	1.09%

The trend is increasing in almost all states and New Hampshire, North Dakota, Wyoming, and South Dakota have rapid growth over 3%. Ten states are growing at less than 1%. California and Tennessee have negative trends.

Natural Gas

Table D.27: Estimated trends for residential natural gas energy intensity

R-square = 0.97

Natural Gas Energy Intensity Trends

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Vermont	3.09%	0.20%	15.5	0	2.70%	3.48%
Washington	2.66%	0.35%	7.67	0	1.98%	3.34%
Idaho	2.60%	0.57%	4.59	0	1.49%	3.72%
Oregon	2.53%	0.34%	7.43	0	1.87%	3.20%
New Jersey	1.57%	0.13%	11.72	0	1.31%	1.84%
North Carolina	1.39%	0.21%	6.54	0	0.97%	1.80%
Tennessee	1.16%	0.17%	6.7	0	0.82%	1.50%
New Hampshire	0.98%	0.14%	7.06	0	0.71%	1.25%
Connecticut	0.83%	0.11%	7.31	0	0.61%	1.05%
Rhode Island	0.81%	0.14%	5.78	0	0.54%	1.09%
North Dakota	0.60%	0.26%	2.31	0.021	0.09%	1.10%
Virginia	0.56%	0.20%	2.88	0.004	0.18%	0.95%
Massachusetts	0.55%	0.18%	3.11	0.002	0.20%	0.90%
New York	0.44%	0.09%	4.68	0	0.25%	0.62%
Delaware	0.23%	0.16%	1.42	0.157	-0.09%	0.55%
Minnesota	0.19%	0.14%	1.37	0.172	-0.08%	0.47%
South Carolina	0.15%	0.53%	0.28	0.777	-0.88%	1.18%
South Dakota	-0.08%	0.29%	-0.28	0.777	-0.65%	0.48%
Wisconsin	-0.09%	0.14%	-0.61	0.541	-0.36%	0.19%
Michigan	-0.12%	0.17%	-0.69	0.491	-0.45%	0.22%
Nevada	-0.20%	0.22%	-0.9	0.367	-0.64%	0.24%
New Mexico	-0.28%	0.17%	-1.61	0.109	-0.62%	0.06%
Wyoming	-0.31%	0.34%	-0.94	0.349	-0.97%	0.34%
Montana	-0.50%	0.24%	-2.08	0.037	-0.96%	-0.03%
Colorado	-0.53%	0.23%	-2.3	0.022	-0.98%	-0.08%
Indiana	-0.61%	0.13%	-4.79	0	-0.86%	-0.36%
Iowa	-0.62%	0.15%	-4.21	0	-0.91%	-0.33%
Illinois	-0.63%	0.13%	-4.78	0	-0.89%	-0.37%
Georgia	-0.64%	0.18%	-3.53	0	-0.99%	-0.28%
Pennsylvania	-0.66%	0.12%	-5.65	0	-0.89%	-0.43%
Maryland	-0.72%	0.22%	-3.24	0.001	-1.16%	-0.28%
Ohio	-0.90%	0.14%	-6.6	0	-1.17%	-0.63%
Mississippi	-0.98%	0.22%	-4.4	0	-1.41%	-0.54%
Nebraska	-1.01%	0.14%	-7.22	0	-1.29%	-0.74%
Alabama	-1.11%	0.15%	-7.6	0	-1.40%	-0.82%
West Virginia	-1.46%	0.18%	-8.05	0	-1.81%	-1.10%
Kentucky	-1.52%	0.24%	-6.32	0	-1.99%	-1.05%
Oklahoma	-1.52%	0.17%	-8.92	0	-1.85%	-1.18%
Utah	-1.55%	0.30%	-5.11	0	-2.15%	-0.96%
Arkansas	-1.62%	0.13%	-12.16	0	-1.89%	-1.36%

Kansas	-1.64%	0.19%	-8.61	0	-2.02%	-1.27%
Missouri	-1.65%	0.14%	-11.63	0	-1.93%	-1.37%
California	-1.91%	0.16%	-11.68	0	-2.23%	-1.59%
Maine	-2.15%	2.20%	-0.98	0.329	-6.47%	2.17%
Arizona	-2.52%	0.32%	-7.92	0	-3.15%	-1.90%
Louisiana	-2.59%	0.23%	-11.37	0	-3.04%	-2.15%
Texas	-2.72%	0.31%	-8.76	0	-3.33%	-2.11%
Florida	-2.90%	0.37%	-7.9	0	-3.61%	-2.18%

The table shows large differences in the trends. Seventeen states have positive trends with four states growing over 2% per year. Thirty-one states have declining natural gas energy intensity and five states are declining faster than 2% a year. Overall, the results show a wide range in the trends for this variable.

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

11. Does KIUC contend that an increase in electricity rates would result in no long-term reduction in the amount of electricity used by Kentucky Power's customers?

(a) If the answer to this data request is anything but an unqualified "yes," please provide each fact relied upon by KIUC in failing to answer with an unqualified "yes."

(b) If the answer to this data request is anything but an unqualified "yes," please provide each document relied upon by KIUC in failing to answer with an unqualified "yes."

RESPONSE:

a, b. No. Generally, price increases tend to result in demand or usage reductions. This effect commonly is referred to as price elasticity of demand. Mr. Kollen has not researched this issue, but there are industry and scholarly articles that address this phenomenon that are publicly available and that can be researched by the Company.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

SPONSORING WITNESS: Lane Kollen

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

12. Please refer to page 6, lines 1 through 3, of Mr. Taylor's testimony.

(a) Please identify and provide all support relied upon by Mr. Taylor in stating "Over the same time period, renewable technology costs in the broader market have declined substantially,..."

(b) Please identify all proposals, including the parties, all relevant proposal terms, and whether the proposals resulted in contracts, referenced by Mr. Taylor in stating "I have seen 20-year REPA proposals offered at contract prices that are less than a third of the ecoPower REPA's price."

RESPONSE:

(a) I have overseen several large renewable solicitations over the 2011-2013 period. As the independent evaluator in those solicitations, I have reviewed over 1,500 proposals for renewable energy projects and associated power purchase agreements and have directly observed declining contract prices in the renewable area in recent years. Also, I have

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

witnessed utility clients deciding to forego executing rather attractive REPAs lately (i.e., at contract prices that are significantly lower than just a few years ago) because they procured market research that concludes that renewable technology prices are likely to decline further.

(b) My independent evaluation engagements are conducted under confidentiality provisions that prevent me from disclosing details of the proposals that are received.

SPONSORING WITNESS: Alan Taylor.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

13. Please refer to page 15 of Mr. Taylor's testimony.

(a) Please provide all work papers, spreadsheets, and calculations electronically, with formulas intact and visible, and no pasted values, used by Mr. Taylor in his calculation of a base case average renewable energy credit (REC) price of over $50/REC over the life of the REPA.

(b) Please identify each assumption relied upon by Mr. Taylor in connection with his calculation referenced in part (a) above and all authority relied upon by Mr. Taylor in electing to use any such assumptions.

(c) Please identify and provide all additional support for Mr. Taylor's calculation referenced in part (a) above.

(d) Please provide all work papers, spreadsheets, and calculations electronically, with formulas intact and visible, and no pasted values, used by Mr. Taylor in his calculation of a "highest energy and capacity price scenario" average REC price of over $38/REC over the life of the REPA.

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

(e) Please identify each assumption relied upon by Mr. Taylor in connection with his calculation referenced in part (d) above and all authority relied upon by Mr. Taylor in electing to use any such assumptions.

(f) Please identify and provide all additional support for Mr. Taylor's calculation referenced in part (d) above.

RESPONSE:

(a) Please see the "base" worksheet of the attached KIUC Response to KPSC Data Request 3 - REC Cost Spreadsheet. Note that this spreadsheet contains confidential information, which has been highlighted in yellow.

(b) As noted in my testimony, I relied on the ecoPower REPA's contract price and on base case market prices for energy and capacity that were provided by Kentucky Power in response to KIUC Data Request 1-10 (where KIUC requested such forecasts of "prices at which Kentucky Power may be able to buy or sell energy in the future"). The forecast

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

that was provided by Kentucky Power included a 'BASE' Fleet Transition CSAPR scenario (that I used for my base case analysis) and several alternate scenarios, all extending from 2012 through 2030. For years beyond 2030, I extended the price forecasts by the escalation rate that was exhibited in the last five years (i.e., 2025-2030) of Kentucky Power's forecasts; those later-year trends showed fairly smooth underlying assumptions in Kentucky Power's forecast. I used Kentucky Power's assumption of 88% expected capacity factor for the ecoPower facility to convert the utility's capacity price forecast from $/MW-day into $/MWh. In addition, for blending on-peak and off-peak prices into annual averages, I assumed percentages that were based on 6 days/week and 16 hours/day on-peak designation (which is fairly standard in most wholesale electricity markets). I did not attempt to factor in holidays or 5 days/week on-peak assumptions as this only would have increased the REC cost calculation, and I wanted to be conservative in my assumptions.

(c) Everything is provided in response to (a) and (b) above.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

**KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS**

(d) Please see the "high" worksheet of the attached KIUC Response to KPSC Data Request 3 - REC Cost Spreadsheet. Note that this spreadsheet contains confidential information, which has been highlighted in yellow.

(e) Please see the response to part (b) above, noting however that for the high market price analysis, I used the FT-CSAPR HIGHER Band scenario of Kentucky Power's energy and capacity price forecast from its response to KIUC Data Request 1-10. All other processes and assumptions were identical to those described in part (b) above.

(f) Everything is provided in the above responses.

SPONSORING WITNESS: Alan Taylor.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

14. Please refer to the last three lines on page 15 of Mr. Taylor's testimony. Does KIUC contend that current spot market prices for RECs are indicative of future REC prices?

(a) If the answer to this data request is anything but an unqualified "yes," please provide each fact relied upon by KIUC in failing to answer with an unqualified "yes."

(b) If the answer to this data request is anything but an unqualified "yes," please provide each document relied upon by KIUC in failing to answer with an unqualified "yes."

RESPONSE:

(a) No, market prices fluctuate and current spot market prices for RECs may not be indicative of future REC prices. Future REC prices will depend on future REC supply and demand factors that cannot be known with certainty and precision. As stated in my testimony, however, I have seen negative REC prices associated with many recent renewable energy options. While I do not think that this will translate into negative REC

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

market prices, the fact that there are renewable opportunities that are so much less expensive than the ecoPower project will put downward pressure on future REC market prices and probably keep them from increasing anywhere near the range of the projected costs of the ecoPower RECs.

(b) There are numerous instances where recent renewable resource analyses performed by Sedway Consulting and/or soliciting utilities have resulted in negative renewable premiums or REC prices for renewable project proposals. The reports that depict the results of these analyses have been filed with state commissions under confidential seal, as disclosing that information would violate confidentiality agreements with bidders. Also, Sedway Consulting's independent evaluation engagements are conducted under confidentiality provisions with the soliciting utility that prevent me from disclosing details of the evaluation results of proposals that are received.

SPONSORING WITNESS: Alan Taylor.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS

15. Please refer to page 16 of Mr. Taylor's testimony.

(a) Please identify all proposed renewable project referenced by Mr. Taylor in stating "In fact, I have seen many proposed renewable projects in recent years that could generate renewable energy and RECs at prices that are less than the forecasted prices for "brown" power." For each renewable project or proposed project referenced by Mr. Taylor please provide the following information:

(i) Project technology type (wind, solar, etc.);

(ii) State in which the project is located;

(iii) Name of the RTO in which the project is located;

(iv) Price of renewable energy; and

(v) Price of RECs.

(b) Please define "brown power."

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

RESPONSE:

(a) Sedway Consulting's independent evaluation engagements are conducted under confidentiality provisions with the soliciting utility that prevent me from disclosing details of the proposals that were received or the evaluation results of such proposals. Thus, I am prevented from providing the requested information for specific proposals. However, some of the requested information below can be provided on an aggregated basis.

(i) Project technology type: wind and solar;

(ii) State in which such proposed projects are located: Arizona, California, Colorado, Iowa, Minnesota, New Mexico, North Dakota, Oregon, South Dakota, and Wisconsin;

(iii) Name of the RTO in which the proposed projects are located: various;

(iv) Price of renewable energy: confidential; and

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO
KENTUCKY POWER'S
FIRST SET OF DATA REQUESTS

(v) Price of RECs: confidential, but calculated to be a negative value.

(b) "Brown power" refers to any wholesale electricity market power that is generated predominantly or entirely from non-renewable energy resources (e.g., fossil-fueled, nuclear, etc.) and thus does not have any RECs or green attributes associated with it.

SPONSORING WITNESS: Alan Taylor.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

16. Please refer to page 18 of Mr. Taylor's testimony. Please identify and provide all support relied upon by Mr. Taylor in stating "If the current REPA was approved, that [higher diesel fuel costs] could lead to another regulatory proceeding in the future regarding an amended REPA with yet a higher price."

RESPONSE:

In my experience as an independent evaluator, I have observed situations where renewable project developers have encountered project cost increases that were outside of their control. Under such circumstances, the state commissions have sometimes been approached to allow an increase in the contract price for an already-approved REPA to cover such cost increases. Given the contractual and regulatory momentum behind an approved REPA (and perhaps even a completed project), it can be difficult for a commission to turn down such a request.

In the case of the ecoPower transaction, the developer explicitly approached Kentucky Power with a proposal that would have transferred the risk of significant fluctuations in fuel supply costs (in which diesel fuel costs factor prominently) to Kentucky Power and its customers.

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

Kentucky Power declined to pursue this proposal, opting instead for a fixed-price REPA. However, as noted above, this does not guarantee that the risk of fuel price increases is settled. Instead, if fuel prices trend low in a fixed-price REPA, the developer enjoys higher-than-expected profits. If fuel prices move higher, the developer's profits are decreased. If they move high enough, the project may face bankruptcy without an increase to the REPA contract price. This has led some other utilities to include diesel-fuel-price adjustment mechanisms in their REPA contract prices for biomass resources – so they do not face this "heads the developer wins, tails the utility loses" type of predicament. Details of specific examples of such contracts that Sedway Consulting has reviewed are confidential.

SPONSORING WITNESS: Alan Taylor.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

17. Please identify and provide copies all testimony filed by Mr. Kollen, on behalf of any client, where he advocated that a utility increase the fuel diversity of its generation resources.

RESPONSE:

Please refer to Mr. Kollen's testimony in KPSC Case No. 2012-00578.

SPONSORING WITNESS: Lane Kollen.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

18. Please identify and provide copies of all testimony filed by Dr. Coomes, on behalf of any client, or any articles or other published works, where he advocated that a utility increase the fuel diversity of its generation resources.

RESPONSE:

I have never testified on behalf of any client (or any articles or other published works) that a utility increase, or decrease, the fuel diversity of its generation resources.

SPONSORING WITNESS: Paul Coomes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

19. Please identify and provide copies of all testimony filed by Mr. Taylor, on behalf of any client, where he advocated that a utility increase the fuel diversity of its generation resources.

RESPONSE:

I have not sponsored or filed testimony in which I advocated that a utility increase fuel diversity of its generation portfolio per se. Instead, I have overseen numerous conventional resource and renewable energy solicitations and filed testimony and independent evaluation reports with state commissions where I have advocated the approval of contracts that were determined to be the best options for adding resources to a utility's generation portfolio and meeting the utility's needs (which, among other factors, may have included fuel diversity benefits). Such determination was always confirmed by vetting the cost-effectiveness of each contract to the results of a competitive solicitation for power supply alternatives.

SPONSORING WITNESS: Alan Taylor.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	))))))))	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

20. Please identify and provide copies of all testimony filed by Mr. Kollen, on behalf of any client, where he advocated that a utility increase the amount of renewable generation in its generation portfolio.

RESPONSE:

None. In general and in the absence of a renewables mandate, Mr. Kollen would advocate an increase in the amount of renewable generation only if there was a need for the resource and only if it were the least cost alternative.

SPONSORING WITNESS: Lane Kollen.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

21. Please identify and provide copies of all testimony filed by Dr. Coomes, on behalf of any client, where he advocated that a utility increase the amount of renewable generation in its generation portfolio.

RESPONSE:

I have never testified on behalf of any client that a utility increase, or decrease, the amount of renewable generation in its portfolio.

SPONSORING WITNESS: Paul Coomes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief	)	Case No. 2013-00144

PUBLIC VERSION

KIUC'S RESPONSE TO KENTUCKY POWER'S FIRST SET OF DATA REQUESTS

22. Please identify and provide copies of all testimony filed by Mr. Taylor, on behalf of any client, where he advocated that a utility increase the amount of renewable generation in its generation portfolio.

RESPONSE:

I have not sponsored or filed testimony in which I advocated that a utility increase the amount of renewable generation in its generation portfolio per se. Instead, I have overseen numerous renewable energy solicitations and filed independent evaluation reports with state commissions where I have advocated the approval of dozens of REPAs that were determined to be the best options for adding renewable generation to a utility's generation portfolio. Such determination was always confirmed by vetting the cost-effectiveness of each REPA to the results of a competitive solicitation for renewable energy alternatives.

SPONSORING WITNESS: Alan Taylor.