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LEGISLATIVE
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MEMORANDUM

November 5, 2008

TO: **Temporary Co-Chairpersons Senator Joe Bolkcom and Representative Nathan Reichert and Members of the Energy Efficiency Plans and Programs Study Committee**

FROM: **Richard Nelson, Senior Legal Counsel, Legal Services Division, Legislative Services Agency**

RE: **Background Information**

The purpose of this memorandum is to provide background information to the members of the Energy Efficiency Plans and Programs Study Committee. In anticipation of the Committee's first meeting on November 13, 2008, the following documents are attached:

- Committee Charge.
- Committee Member Contact Information.
- Tentative Meeting Agenda for November 13 Meeting.
- Proposed Committee Rules.
- Energy Efficiency Plans and Programs Statutory Requirements Summary.
- History of Energy Efficiency Initiatives.
- Copy of Senate File 2386 (Legislation containing new energy efficiency planning and reporting requirements and requesting authorization of the Committee by the Legislative Council).
- Copy of Senate File 517 (Legislation relating to state building code requirements and energy efficiency programs and activities under the purview of the Department of Natural Resources).
- Who Should Administer Energy-Efficiency Programs (third-party administration background material for second meeting on December 3).
- Revenue Decoupling Standards and Criteria (decoupling and utility incentives background material for second meeting on December 3).

Additional information received and distributed in connection with all meetings of this Committee will be posted on the Committee's web site at: http://www.legis.state.ia.us/aspx/Committees/Committee.aspx?id=237.

Energy Efficiency Plans and Programs Study Committee

CHARGE: Examine the existence and effectiveness of energy efficiency plans and programs implemented by gas and electric public utilities, with an emphasis on results achieved by current plans and programs from the demand, or customer, perspective, and make recommendations for additional requirements applicable to energy efficiency plans and programs that would improve such results. In conducting the study and developing recommendations, the Study Committee shall consider testimony from the Iowa Utilities Board, rate-regulated and nonrate-regulated gas and electric utilities, the Consumer Advocate, state agencies involved with energy efficiency program administration, environmental groups and associations, and consumers.

MEETINGS: 2 Meeting Days

MEMBERS: 5 Senate, 5 House

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Members

Energy Efficiency Plans and Programs Study Committee

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ENERGY EFFICIENCY PLANS AND PROGRAMS STUDY COMMITTEE

MEMBERSHIP

Senator Joe Bolkcom, Co-chair	*Representative Nathan Reichert, Co-chair*
Senator William M. Heckroth	*Representative Paul A. Bell*
Senator David Johnson	*Representative Bob Kressig*
Senator Rich Olive	*Representative Chuck Soderberg*
Senator Pat Ward	*Representative Ralph C. Watts*

Tentative Agenda

Thursday, November 13, 2008
Room 19, State Capitol

9:00 a.m.	**Introduction** Call to Order Roll Call Opening Remarks Adoption of Rules Election of Co-chairpersons
9:15 a.m.	**Iowa Utilities Board** Joan Conrad, Legislative Liaison, Iowa Utilities Board John Norris, Chairperson, Iowa Utilities Board
	Utility Plans and Programs
10:00 a.m.	MidAmerican Energy Rick Leuthauser, Manager of Energy Efficiency, MidAmerican Energy
10:30 a.m.	Alliant Energy/Interstate Power and Light Kim King, Manager of Energy Efficiency and Demand Side Management, Alliant Energy
11:00 a.m.	**Break**
11:15 a.m.	Iowa Association of Electric Cooperatives Regi Goodale, Director of Regulatory Affairs, Iowa Association of Electric Cooperatives
11:45 a.m.	Iowa Association of Municipal Utilities Bob Haug, Executive Director, Iowa Association of Municipal Utilities
12:15 p.m.	**Lunch**
	Energy Efficiency Plan Perspectives
1:15 p.m.	Iowa Policy Project David Osterberg, Executive Director, Iowa Policy Project
1:35 p.m.	Office of Consumer Advocate John Perkins, Consumer Advocate, Office of Consumer Advocate Jennifer Easler, Attorney, Office of Consumer Advocate
1:50 p.m.	Iowa Environmental Council Nathaniel Baer, Energy Program Director
2:05 p.m.	Plains Justice Carrie La Seur, President, Plains Justice
2:20 p.m.	Office of Energy Independence Roya Stanley, Director, Office of Energy Independence

3:00 p.m.	**Committee Discussion**
3:30 p.m.	**Adjourn**

PROPOSED RULES

Energy Efficiency Plans and Programs Study Committee

1. Six of the voting members shall constitute a quorum, but a lesser number of members may adjourn or recess the Committee in the absence of a quorum.
2. A majority vote of those voting members present is necessary to carry any action; however, no recommendations to the Legislative Council or General Assembly may be adopted without the affirmative votes of at least three members of each house.
3. Whenever Mason's Manual of Legislative Procedure does not conflict with the rules specifically adopted by the Committee, Mason's Manual of Legislative Procedure shall govern the deliberations of the Committee.
4. Meetings shall be set by motion before adjournment, or by call of the Co-Chairpersons of the Committee if meetings are necessary before the date set in the motion.
5. Rules shall be adopted by the affirmative votes of at least three members of each house and may only be changed or suspended by a similar vote of the Committee.

Submitted:

November 13, 2008

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LEGISLATIVE SERVICES AGENCY

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October 30, 2008

TO: **Co-chairpersons Senator Joe Bolkcom and Representative Nathan Reichert and Members of the Energy Efficiency Plans and Programs Study Committee**

FROM: **Richard Nelson, Senior Legal Counsel, Legal Services Division, Legislative Services Agency**

RE: **Energy Efficiency Plans and Programs Statutory Requirements**

I. Overview

This memorandum provides basic background information on the statutory requirements for energy efficiency plans and programs for consideration by the Committee.

Energy efficiency programs are required to be developed and offered to customers of gas and electric public utilities, under the purview of the Iowa Utilities Board as provided in Code Chapter 476. The programs can be offered either directly by the utility or by a third party or agent contracted with the utility.[1] The programs are contained within energy efficiency plans which are filed with the board.[2] Energy efficiency plans are, in general, required to be cost-effective, other than programs for qualified low-income persons and relating to tree planting, education, and assessments of consumers' needs for information to make effective choices regarding energy use and energy efficiency.[3]

II. Rate-Regulated (Investor-Owned) Utilities

With regard to gas and electric utilities subject to rate regulation pursuant to Code Chapter 476, energy efficiency plans are required to be developed and filed with the board, and must include a range of programs offering energy efficiency opportunities tailored to the needs of all customer classes, including residential, commercial, and industrial customers.[4] Programs relating to low-income energy assistance can take the form of a countywide or communitywide program in cooperation with one or more community action agencies within a utility's service area. Iowa agencies and contractors are to be utilized to the maximum extent that is cost-effective in implementing programs contained within the plans.[5]

Additionally, rate-regulated gas and electric utilities are required to submit an assessment to the board determining potential energy and capacity savings available from actual and projected customer usage through the application of commercially available technology and improved operating practices to energy-using equipment and buildings. Based on the assessments, and in consultation with the Department of Natural Resources, the board develops specific capacity and energy savings performance standards for incorporation into a utility's energy efficiency plan. The board may approve, reject, or modify submitted plans, conduct contested case proceedings, and must periodically report the energy efficiency results including energy savings of each utility to the General Assembly.[6]

III. Nonrate-Regulated (Consumer-Owned) Utilities

Energy efficiency plans are also required to be filed by nonrate-regulated gas and electric utilities, but are not subject to board approval. Electric public utilities having fewer than 10,000 customers and electric cooperative corporations and associations, municipally owned utilities furnishing gas or electricity, and gas public utilities having fewer than 2,000 customers, must submit plans which are, on the whole, cost-effective. Plans may be submitted individually or in combination with other similarly classified utilities, and may be waived by the board in whole or in part if a utility can demonstrate superior results with existing energy efficiency efforts. Electric public utilities having fewer than 10,000 customers, electric cooperative corporations and associations, and municipally owned utilities must, as in the case of rate-regulated utilities, periodically report the energy efficiency results including energy savings to the General Assembly.[7]

IV. Energy Efficiency Goals and Reporting — New Requirements

Senate File 2386, enacted in 2008, established new requirements relating to the assessment of energy efficiency savings potential and the establishment of energy efficiency goals and programs by nonrate-regulated gas and electric utilities, and imposed new reporting responsibilities applicable to the board with regard to all gas and electric public utilities.

In a requirement comparable to provisions noted above that apply to rate-regulated gas and electric public utilities, nonrate-regulated utilities are now required to assess maximum potential energy and capacity savings available from actual and projected customer usage through cost-effective energy efficiency measures and programs, taking into account the utility service area's historic energy load, projected demand, customer base, and other relevant factors. Based on this assessment, the utility is then required to establish an energy efficiency goal, which may be separately established for different customer groupings, and cost-effective programs to meet that goal.

The legislation contains a nonexclusive list of various forms or types of energy efficiency programs, including efficiency improvements to a utility infrastructure and system and activities conducted by a utility intended to enable or encourage customers to increase the amount of heat, light, cooling, motive power, or other forms of work performed per unit of energy used. For these purposes, in the case of a municipal utility, other utilities and departments of the municipal utility are considered "customers" to the same extent that such utilities and departments would be considered customers if served by an electric or gas utility that is not a municipal utility. Examples of energy programs include activities which lessen the amount of heating, cooling, or other forms of work which must be performed, including but not limited to energy studies or audits, general information, financial assistance, direct rebates to customers or vendors of energy-efficient products, research projects, direct installation by the utility of energy-efficient equipment, direct and indirect load control, time-of-use rates, tree planting programs, educational programs, and hot water insulation distribution programs.

Nonrate-regulated utilities are required to begin the process of determining their cost-effective energy efficiency goal by July 1, 2008, to submit a progress report to the board on or before January 1, 2009, and to complete the process and submit a final report to the board on or before January 1, 2010. The report is to contain the goal arrived at, and for each measure utilized by the utility in meeting the goal, the measure's description, projected costs, and an analysis of its cost-effectiveness utilizing existing cost-effectiveness tests already applicable to rate-regulated utilities contained in Code Section 476.6, subsection 14. Individual nonrate-regulated utilities or groups of such utilities are allowed to collaborate in satisfying these requirements and may file a joint report, subject to the board's ability to request and require individualized information from a particular utility. After submitting a final report, subsequent reports identifying progress in meeting the goals, and relating any updates or amendments to energy plans and goals, are required to be submitted to the board on January 1, 2012, and every even-numbered year thereafter.

Based upon its evaluation of the reports required to be filed by nonrate-regulated utilities pursuant to the legislation, and the assessments and plans required to be filed by rate-regulated utilities pursuant to Code Section 476.6, subsection 16, paragraph "b," the board is directed to submit reports summarizing the evaluations to the General Assembly by January 1, 2009, and January 1, 2011, respectively. The reports submitted by the board are required to include the goals established by each utility, the projected costs of achieving the goals, potential rate impacts, and a description of the energy efficiency programs offered and proposed by each utility or groups of utilities. The reports may contain recommendations relating to the achievability of intermediate and long-term energy efficiency goals.[8]

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[1] Iowa Code § 476.6(14).
[2] Iowa Code §§ 476.1A-476.1C, and 476.6(16).
[3] Iowa Code § 476.6(14).
[4] Iowa Code § 476.6(16).
[5] Iowa Code § 476.6(16).
[6] Iowa Code § 476.6(16).
[7] Iowa Code §§ 476.1A-476.1C. Note reporting requirements imposed upon the Iowa Utilities Board on behalf of utilities in 2008 Iowa Acts, ch 1133, Sec. 4.
[8] 2008 Iowa Acts, ch 1133.

Iowa Utilities Board
History of Energy Efficiency Initiatives

1980-1984: The Iowa Commerce Commission (renamed the Iowa Utilities Board in 1988) required investor-owned utilities to provide energy audits. Utilities or subcontractors by 1989, provided energy audits to about 10% of customers, but energy savings impacts were not identifiable.

1985-1986: The Iowa legislature mandated conservation pilot programs by investor-owned utilities. Programs were focused on loans for high-efficiency natural gas furnaces. Utilities recovered costs for the programs charge identified on customers' bills. The legislature repealed the law in 1986, because of a large number of customer complaints regarding the charge.

1987-1988: Utilities began planning new power plants to meet increased demand, and the Commission started a general inquiry into utility energy efficiency. The Commission also ordered Iowa Power (a predecessor of MidAmerican Energy) to increase energy conservation activities, as a condition for approval of a power plant.

1989-1990: The Board and a consultant, Morgan Systems Corporation, conducted an intensive study of utility planning and energy conservation in Iowa. Morgan System's report was the basis for legislation passed in 1990 (Senate File 2403). The legislation mandated spending on energy efficiency by investor-owned utilities, at a level of about 2% of revenues for electric programs and 1.5 % of revenues for gas programs. Programs by consumer-owned utilities were to be voluntary, with mandatory reporting of results.

- Investor-owned utility (IOU) energy efficiency plans were reviewed in contested cases conducted by the Iowa Utilities Board (IUB).
- Targeted levels of spending by IOUs were designated: 2% of revenues for electric programs and 1.5% of revenues for natural gas programs.
- Certain programs were mandated for IOUs: water heater blankets, commercial lighting, rebates for lighting, tree planting and low-income programs (in cooperation with Community Action weatherization agencies.
- Cost recovery by IOUs could only occur after contested cases before the IUB, with a lag of several years between spending and cost recovery.
- Various additional incentives to utilities were authorized, including rewards, penalties and returns on all IOU expenditures.
- Research, demonstration and education on energy efficiency, renewables and climate change was to be conducted by the Iowa Energy Center and the Center for Global and Regional Environmental Research, funded by all energy utilities at a rate of 0.1% of revenues.

- Investor-owned utilities were required to purchase electricity from renewable electricity producers, up to a specified level of 105 MW or about 2% of total capacity.
- Consumer-owned utilities were required to file biennial voluntary energy efficiency plans and to report on results.

1991-1992: The Iowa Utilities Board (Board) established rules for utility energy efficiency programs. The Board then held contested case hearings to review and approve energy efficiency plans. Many operating principles were established by rules or in the contested reviews, such as benefit/cost methods, determination of avoided costs and treatment of environmental impacts. Utilities began implementing energy efficiency programs.

1993-1995: Utilities continued to implement their first energy efficiency plans, with occasional changes to plans. Cost recovery hearings were conducted by the Board to review results of programs and allow utilities to begin recovering past expenses.

1996-1997: Various parties pressed for changes in energy efficiency legislation. The Board proposed legislation resulting in the passage of Senate File 2370. Utilities began recovering a large amount of accumulated energy efficiency costs, plus costs for ongoing programs.

- Investor-owned utility (IOU) energy efficiency plans continue to be reviewed in contested cases conducted by the Iowa Utilities Board (IUB).
- Utilities' energy efficiency plans must be cost-effective, with four benefit-cost tests to be used to determine cost-effectiveness.
- Plan must include programs for all types of customers, and should use Iowa contractors if cost-effective.
- Goals are not expressed as spending targets. Low-income weatherization programs are the only mandate, but no spending targets are specified.
- IOU energy efficiency plans must include an analysis of potential for energy efficiency, and plans must be designed to attain performance standards.
- IOU cost recovery is through an automatic rate "rider" or pass-through, reconciled annually to prevent over-recovery or under-recovery.
- The IUB is authorized to conduct prudence reviews of IOU energy efficiency, with authority to disallow imprudent costs.

1998: A proposal was made by a utility to unbundle energy efficiency and renewable energy costs, which would call attention to these costs on customers' bills. The Board found the information program explaining the new billing system to be inadequate, and the billing proposal was abandoned. The Board also adopted new energy efficiency planning rules.

1999-2000: The debate about electric restructuring produced various proposals for funding public benefits. The Board reviewed the implementation of energy efficiency by two utilities, and rejected one utility's proposal to reduce its energy efficiency budget.

2001-2003: Legislators rejected electric industry restructuring but passed House File 577 which was intended to encourage the expansion of electric generation. Harsh winter weather in 2000 contributed to a short but dramatic spike in natural gas prices. The Board instructed investor-owned utilities to develop new energy efficiency plans.

2003-2004: The Board delivered a report to the General Assembly on utility rates, which addressed certain topics relating to energy efficiency that were suggested by participants. The Board found that allowing large customer to exempt themselves from energy efficiency programs would undermine cost-effectiveness of programs.

2003-2005: All investor-owned utilities filed new energy efficiency plans, which were reviewed in contested case proceedings. All issues for the plans of MidAmerican Energy, Aquila and Atmos were resolved by settlement among the parties to the proceedings. Most issues regarding the Alliant Energy plans were also settled, but issues relating to the interruptible load management program of Alliant continued to be disputed, until settlements were reached in 2005.

2004-2007: Investor-owned utilities began implementing new plans, with some new or enhanced programs including: residential appliance recycling, performance contracting, agriculture energy efficiency, bidding for efficiency rebates by large customers and specialized technical assistance to nonresidential customers.

2004-2007: The Board on its own initiative directed the investor-owned utilities to double funding for low-income energy efficiency programs, and authorized the utilities to undertake pilot projects for low-income efficiency education and multi-family low-income energy efficiency.

2005-2007: Customer response to new programs and rising prices of natural gas significantly increased results and spending by investor-owned utility energy efficiency programs.

January 2008: The Board provided two reports to the legislature and governor, titled "Status of Energy Efficiency Programs in Iowa" and "2007 Survey of Iowa Residential Utility Customers." The Board issued an order on January 14, 2008, scheduling the filing of new energy efficiency plans by investor-owned utilities and requiring in the plans additional information on the effects of establishing goals for energy savings equal to 1.5 percent of retail sales. The investor owned utilities have filed their new plans for the five-year period beginning in 2009; the plans are currently docketed before the IUB.

2008: SF 2386 was one of two omnibus energy bills passed during the 2008 Session. In the area of energy efficiency it directed non-rate regulated utilities to:

- Assess their maximum potential energy and capacity savings
- Establish an energy efficiency goal based upon this assessment of potential
- Establish cost-effective energy efficiency programs designed to meet the goal
- Submit a progress report to the IUB by January 1, 2009
- Submit a final report to the IUB by January 1, 2010
- IUB to evaluate reports and report to General Assembly by January 1, 2011
- IUB to evaluate rate-regulated utilities and report by January 1, 2009
- Both IUB reports are to include the goals established by each utility and the projected costs of achieving the goals, potential rate impacts, and a description of the programs offered. The reports may also include recommendations concerning the achievability of intermediate and long-term energy efficiency goals based upon the results of the assessments submitted by the utilities.

Senate File 2386 - Enrolled

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SENATE FILE 2386

AN ACT

RELATING TO ENERGY EFFICIENCY BY ESTABLISHING A COMMISSION ON ENERGY EFFICIENCY STANDARDS AND PRACTICES, PROVIDING FOR THE REPORTING OF ENERGY EFFICIENCY RESULTS AND SAVINGS BY GAS AND ELECTRIC PUBLIC UTILITIES, SPECIFYING PROCEDURES FOR ASSESSING POTENTIAL ENERGY AND CAPACITY SAVINGS AND DEVELOPING ENERGY EFFICIENCY GOALS BY GAS AND ELECTRIC UTILITIES NOT SUBJECT TO RATE REGULATION, PROVIDING FOR THE ESTABLISHMENT OR PARTICIPATION IN A PROGRAM TO TRACK, RECORD, OR VERIFY THE TRADING OF CREDITS FOR ELECTRICITY GENERATED FROM SPECIFIED SOURCES, AND PROVIDING FOR THE ESTABLISHMENT OF AN INTERIM STUDY COMMITTEE TO CONDUCT AN EXAMINATION OF ENERGY EFFICIENCY PLANS AND PROGRAMS WITH AN EMPHASIS ON THE DEMAND OR CUSTOMER PERSPECTIVE, AND PROVIDING AN EFFECTIVE DATE.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE OF IOWA:

Section 1. NEW SECTION. 103A.27 COMMISSION ON ENERGY EFFICIENCY STANDARDS AND PRACTICES.

1. A commission on energy efficiency standards and practices is established within the department of public safety. The commission shall be composed of the following members:

a. The state building code commissioner, or the commissioner's designee.

b. The director of the office of energy independence, or the director's designee.

c. A professional engineer licensed pursuant to chapter 542B.

d. An architect registered pursuant to chapter 544A.

e. Two individuals recognized in the construction industry as possessing expertise and experience in the construction or renovation of energy=efficient residential and commercial buildings.

f. A member of a local planning and zoning commission or county board of supervisors.

g. Three individuals representing gas and electric public utilities within this state, comprised of one individual representing rural electric cooperatives, one individual representing municipal utilities, and one individual representing investor=owned utilities.

h. A local building official whose duties include enforcement of requirements for energy conservation in construction.

i. Two consumers, one of whom owns and occupies a residential building in this state and one of whom owns and occupies a building used in commercial business or manufacturing.

2. The commissioner shall appoint all members to the commission other than those members designated in subsection

1, paragraphs "a" and "b". Appointment of members are subject to the requirements of sections 69.16 and 69.16A. A vacancy on the commission shall be filled for the unexpired portion of the regular term in the same manner as regular appointments are made. Members appointed by the commissioner shall be reimbursed for actual and necessary expenses incurred in performance of their duties. Such members may also be eligible to receive compensation as provided in section 7E.6. A majority of the members shall constitute a quorum.

3. Duties of the commission shall include but are not limited to the following:

a. Evaluate energy efficiency standards applicable to existing or newly constructed residential, commercial, and industrial buildings and vertical infrastructure at the state and local level and make suggestions for their improvement and enforcement. The evaluation of energy efficiency standards shall include but not be limited to a review of the following:

(1) The reduction in energy usage likely to result from the adoption and enforcement of the standards.

(2) The effect of compliance with the standards on indoor air quality.

(3) The relationship of the standards to weatherization programs for existing housing stock and to the availability of affordable housing, including rental units.

b. Develop recommendations for new energy efficiency standards, specifications, or guidelines applicable to newly constructed residential, commercial, and industrial buildings and vertical infrastructure.

c. Develop recommendations for the establishment of incentives for energy efficiency construction projects which exceed currently applicable state and local building codes.

d. Develop recommendations for adoption of a statewide energy efficiency building labeling or rating system for residential, commercial, and industrial buildings and complexes.

e. Obtain input from individuals, groups, associations, and agencies in carrying out the duties specified in paragraphs "a" through "d", including but not limited to the Iowa league of cities regarding local building code adoption and enforcement in both large and small communities, the Iowa landlord association, the department of transportation, the department of public health, the division of community action agencies of the department of human rights regarding low=income residential customers, and obtain additional input from any other source that the commission determines appropriate.

4. The commission shall be formed for the two=year period beginning July 1, 2008, and ending June 30, 2010, and shall submit a report to the governor and the general assembly by January 1, 2011, regarding its activities and recommendations. Administrative support shall be furnished by the department of public safety, with the assistance of the office of energy independence and the department of natural resources.

Sec. 2. Section 476.1A, subsection 7, Code 2007, is amended to read as follows:

7. Filing energy efficiency plans and energy efficiency ~~results~~ with the board. The energy efficiency plans as a whole shall be cost=effective. The board may permit these utilities to file joint plans. The board shall periodically report the energy efficiency results including energy savings

of each of these utilities to the general assembly.

Sec. 3. Section 476.1B, subsection 1, paragraph 1, Code 2007, is amended to read as follows:

1. Filing energy efficiency plans and energy efficiency results with the board. The energy efficiency plans as a whole shall be cost=effective. The board may permit these utilities to file joint plans. The board shall periodically report the energy efficiency results including energy savings of each of these utilities to the general assembly.

Sec. 4. Section 476.6, subsection 16, paragraph b, Code Supplement 2007, is amended to read as follows:

b. A gas and electric utility required to be rate=regulated under this chapter shall assess potential energy and capacity savings available from actual and projected customer usage by applying commercially available technology and improved operating practices to energy=using equipment and buildings. The utility shall submit the assessment to the board. Upon receipt of the assessment, the board shall consult with the department of natural resources to develop specific capacity and energy savings performance standards for each utility. The utility shall submit an energy efficiency plan which shall include economically achievable programs designed to attain these energy and capacity performance standards. The board shall periodically report the energy efficiency results including energy savings of each utility to the general assembly.

Sec. 5. Section 476.6, subsection 16, Code Supplement 2007, is amended by adding the following new paragraphs:

NEW PARAGRAPH. bb. (1) Gas and electric utilities that are not required to be rate=regulated under this chapter shall assess maximum potential energy and capacity savings available from actual and projected customer usage through cost=effective energy efficiency measures and programs, taking into consideration the utility service area's historic energy load, projected demand, customer base, and other relevant factors. Each utility shall establish an energy efficiency goal based upon this assessment of potential and shall establish cost=effective energy efficiency programs designed to meet the energy efficiency goal. Separate goals may be established for various customer groupings.

(2) Energy efficiency programs shall include efficiency improvements to a utility infrastructure and system and activities conducted by a utility intended to enable or encourage customers to increase the amount of heat, light, cooling, motive power, or other forms of work performed per unit of energy used. In the case of a municipal utility, for purposes of this paragraph, other utilities and departments of the municipal utility shall be considered customers to the same extent that such utilities and departments would be considered customers if served by an electric or gas utility that is not a municipal utility. Energy efficiency programs include activities which lessen the amount of heating, cooling, or other forms of work which must be performed, including but not limited to energy studies or audits, general information, financial assistance, direct rebates to customers or vendors of energy=efficient products, research projects, direct installation by the utility of energy=efficient equipment, direct and indirect load control, time=of=use rates, tree planting programs, educational programs, and hot water insulation distribution programs.

(3) Each utility shall commence the process of determining its cost=effective energy efficiency goal on or before July 1, 2008, shall provide a progress report to the board on or before January 1, 2009, and complete the process and submit a final report to the board on or before January 1, 2010. The report shall include the utility's cost=effective energy efficiency goal, and for each measure utilized by the utility in meeting the goal, the measure's description, projected costs, and the analysis of its cost=effectiveness. Each utility or group of utilities shall evaluate cost=effectiveness using the cost=effectiveness tests in accordance with section 476.6, subsection 14. Individual utilities or groups of utilities may collaborate in conducting the studies required hereunder and may file a joint report or reports with the board. However, the board may require individual information from any utility, even if it participates in a joint report.

(4) On January 1 of each even=numbered year, commencing January 1, 2012, gas and electric utilities that are not required to be rate=regulated shall file a report with the board identifying their progress in meeting the energy efficiency goal and any updates or amendments to their energy efficiency plans and goals. Filings made pursuant to this paragraph "bb" shall be deemed to meet the filing requirements of section 476.1A, subsection 7, and section 476.1B, subsection 1, paragraph "l".

<u>NEW PARAGRAPH</u>. bbb. (1) The board shall evaluate the reports required to be filed pursuant to paragraph "b" by gas and electric utilities required to be rate=regulated, and shall submit a report summarizing the evaluation to the general assembly on or before January 1, 2009.

(2) The board shall evaluate the reports required to be filed pursuant to paragraph "bb" by gas and electric utilities that are not required to be rate=regulated, and shall submit a report summarizing the evaluation to the general assembly on or before January 1, 2011.

(3) The reports submitted by the board to the general assembly pursuant to this paragraph "bbb" shall include the goals established by each of the utilities. The reports shall also include the projected costs of achieving the goals, potential rate impacts, and a description of the programs offered and proposed by each utility or group of utilities, and may take into account differences in system characteristics, including but not limited to sales to various customer classes, age of facilities of new large customers, and heating fuel type. The reports may contain recommendations concerning the achievability of certain intermediate and long=term energy efficiency goals based upon the results of the assessments submitted by the utilities.

Sec. 6. <u>NEW SECTION</u>. 476.44A TRADING OF CREDITS.

The board may establish or participate in a program to track, record, and verify the trading of credits for electricity generated from alternative energy production facilities or renewable energy sources among electric generators, utilities, and other interested entities, within this state and with similar entities in other states.

Sec. 7. RENEWABLE ENERGY GENERATION == COST=EFFECTIVE POTENTIAL STUDY. The Iowa utility association, in consultation with the Iowa association of electric cooperatives and the Iowa association of municipal utilities, shall conduct a technical study of the potential for achieving or engaging in renewable energy generation on a cost=effective basis by 2025. The study shall be transmitted to the office of energy independence by December 1, 2008, to be submitted with the energy independence plan required to be submitted by the office to the governor and the general assembly by December 14, 2008.

Sec. 8. ENERGY EFFICIENCY INTERIM STUDY COMMITTEE == CONSUMER FOCUS == REQUEST TO ESTABLISH. The legislative council is requested to establish an interim study committee to examine the existence and effectiveness of energy efficiency plans and programs implemented by gas and electric public utilities, with an emphasis on results achieved by current plans and programs from the demand, or customer, perspective, and to make recommendations for additional requirements applicable to energy efficiency plans and programs that would improve such results. In conducting the study and developing recommendations, the committee shall consider testimony from the Iowa utilities board, rate and nonrate=regulated gas and electric utilities, the consumer advocate, state agencies involved with energy efficiency program administration, environmental groups and associations, and consumers. The committee shall be composed of ten members, representing both political parties and both houses of the general assembly. Five members shall be members of the senate, three of whom shall be appointed by the majority leader of the senate and two of whom shall be appointed by the minority leader of the senate. The other five members shall be members of the house of representatives, three of whom shall be appointed by the speaker of the house of representatives, and two of whom shall be appointed by the minority leader of the house of representatives. The committee shall issue a report of its recommendations to the general assembly by January 15, 2009.

Sec. 9. EFFECTIVE DATE. This Act, being deemed of immediate importance, takes effect upon enactment.

JOHN P. KIBBIE
President of the Senate

PATRICK J. MURPHY
Speaker of the House

I hereby certify that this bill originated in the Senate and is known as Senate File 2386, Eighty=second General Assembly.

MICHAEL E. MARSHALL
Secretary of the Senate

Approved ________________, 2008

CHESTER J. CULVER
Governor

Senate File 517 - Enrolled

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SENATE FILE 517

AN ACT

RELATING TO THE DEVELOPMENT, MANAGEMENT, AND EFFICIENT USE OF ENERGY RESOURCES, MAKING ENERGY-RELATED MODIFICATIONS TO THE STATE BUILDING CODE, SETTING FEES, MAKING APPROPRIATIONS, AND PROVIDING AN EFFECTIVE DATE.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE OF IOWA:

Section 1. Section 8.60, subsection 15, Code 2007, is amended by striking the subsection.

Sec. 2. Section 12.28, subsection 6, Code 2007, is amended to read as follows:

6. The maximum principal amount of financing agreements which the treasurer of state can enter into shall be one million dollars per state agency in a fiscal year, subject to the requirements of section 8.46. For the fiscal year, the treasurer of state shall not enter into more than one million dollars of financing agreements per state agency, not considering interest expense. However, the treasurer of state may enter into financing agreements in excess of the one million dollar per agency per fiscal year limit if a constitutional majority of each house of the general assembly, or the legislative council if the general assembly is not in session, and the governor, authorize the treasurer of state to enter into additional financing agreements above the one million dollar authorization contained in this section. The treasurer of state shall not enter into a financing agreement for real or personal property which is to be constructed for use as a prison or prison=related facility without prior authorization by a constitutional majority of each house of the general assembly and approval by the governor of the use, location, and maximum cost, not including interest expense, of the real or personal property to be financed. However, financing agreements for an energy conservation measure, as defined in section 7D.34, for an energy management improvement, as defined in section 473.19, or for costs associated with projects under section 473.13A, are exempt from the provisions of this subsection, but are subject to the requirements of section 7D.34 ~~or 473.20A~~. In addition, financing agreements funded through the materials and equipment revolving fund established in section 307.47 are exempt from the provisions of this subsection.

Sec. 3. Section 103A.3, Code 2007, is amended by adding the following new subsection:

NEW SUBSECTION. 23. "Sustainable design" means construction design intended to minimize negative environmental impacts and to promote the health and comfort of building occupants including but not limited to measures to reduce consumption of nonrenewable resources, minimize waste, and create healthy, productive environments.

Sec. 4. Section 103A.7, subsection 6, Code 2007, is amended to read as follows:

6. The conservation of energy through thermal ~~and lighting~~ efficiency standards for buildings intended for human occupancy ~~or use~~ and which are heated or cooled and lighting efficiency standards for buildings intended for human occupancy which are lighted.

Sec. 5. Section 103A.7, Code 2007, is amended by adding the following new subsection:

NEW SUBSECTION. 7. Standards for sustainable design, also known and referred to as green building standards.

Sec. 6. Section 103A.8, subsections 7 and 8, Code 2007, are amended to read as follows:

7. Limit the application of thermal efficiency standards for energy conservation to ~~new~~ construction of buildings which ~~will incorporate a heating or cooling system~~ are heated or cooled. Air exchange fans designed to provide ventilation shall not be considered a cooling system. The commissioner shall exempt any ~~new~~ construction from any thermal efficiency ~~standards~~ standard for energy conservation if the commissioner determines that the ~~standards are~~ standard is unreasonable as ~~they apply~~ it would apply to a particular building or class of buildings ~~including farm buildings for livestock use~~. No standard adopted by the commissioner for energy conservation in construction shall be interpreted to require the replacement or modification of any existing equipment or feature solely to ensure compliance with requirements for energy conservation in construction. Lighting efficiency standards shall recognize variations in lighting intensities required for the various tasks performed within the building. The commissioner shall consult with the department of natural resources regarding standards for energy conservation prior to the adoption of the standards. However, the standards shall be consistent with section 103A.8A.

8. Facilitate the development and use of ~~solar~~ renewable energy.

Sec. 7. Section 103A.8A, Code 2007, is amended to read as follows:

103A.8A ENERGY CONSERVATION REQUIREMENTS.

The state building code commissioner shall adopt as a part of the state building code a requirement that new single=family or two=family residential construction shall comply with energy conservation requirements. The requirements adopted by the commissioner shall be based upon a nationally recognized standard or code for energy conservation. The requirements shall only apply to single=family or two=family residential construction commenced after the adoption of the requirements. ~~This chapter shall not be construed to prohibit a governmental subdivision from adopting or enacting a minimum energy standard which is substantially in accordance and consistent with energy codes and standards developed by a nationally recognized organization in effect on or after July 1, 2002. A governmental subdivision that adopts or enacts a minimum energy standard which is substantially in accordance and consistent with energy codes and standards developed by a nationally recognized organization shall adopt or enact any update or revision to the energy codes and standards.~~ Notwithstanding any other provision of this chapter to the contrary, the energy conservation requirements adopted by the commissioner and approved by the council shall apply to new single=family or two=family residential construction commenced on or after July 1, 2008, and shall supersede and replace any minimum requirements for energy conservation adopted or enacted by the governmental subdivision prior to that date applicable to such construction. The state building code commissioner may provide training to builders, contractors, and other interested persons on the adopted energy conservation requirements.

Sec. 8. NEW SECTION. 103A.8B SUSTAINABLE DESIGN OR GREEN BUILDING STANDARDS.

The commissioner, after consulting with and receiving recommendations from the department of natural resources and the office of energy independence, shall adopt rules pursuant to chapter 17A specifying standards and requirements for sustainable design and construction based upon or incorporating nationally recognized ratings, certifications, or classification systems, and procedures relating to documentation of compliance. The standards and requirements shall be incorporated into the state building code established in section 103A.7, but in lieu of general applicability shall apply to construction projects only if such applicability is expressly authorized by statute, or as established by another state agency by rule.

Sec. 9. Section 103A.10, subsection 4, paragraphs a and b, Code Supplement 2007, are amended to read as follows:

a. Provisions of the state building code establishing thermal efficiency energy conservation standards shall be applicable to all ~~new~~ construction ~~owned by the state, an agency of the state or a political subdivision of the state, to all new construction located in a governmental subdivision which has adopted either the state building code or a local building code or compilation of requirements for building construction and to all other new construction~~ in the state which will contain ~~more than one hundred thousand cubic feet of~~ enclosed space that is heated or cooled. The commissioner shall provide appropriate exceptions for construction where the application of an energy conservation requirement adopted pursuant to this chapter would be impractical.

b. Provisions of the state building code establishing lighting efficiency standards shall be applicable to all ~~new~~ construction ~~owned by the state, an agency of the state or a political subdivision of the state and to all new construction,~~ in the state~~, of buildings which are open to the general public during normal business hours~~ and to new and replacement lighting in existing buildings.

Sec. 10. Section 103A.10, subsection 5, Code Supplement 2007, is amended by striking the subsection and inserting in lieu thereof the following:

5. Notwithstanding any other provision of this chapter to the contrary, the energy conservation requirements adopted by the commissioner and approved by the council shall apply to all new construction commenced on or after July 1, 2008, and shall supersede and replace any minimum requirements for energy conservation adopted or enacted by the governmental subdivision prior to that date and applicable to such construction.

Sec. 11. Section 103A.10A, subsections 1 and 2, Code Supplement 2007, are amended to read as follows:

1. ~~Beginning on January 1, 2007, all~~ All newly constructed buildings or structures subject to the state building code,

~~excluding~~ including any addition, but excluding any renovation~~,~~ or repair of a building or structure, ~~whether existing prior to January 1, 2007, or thereafter, that are~~ owned by the state or an agency of the state, except as provided in subsection 2, shall be subject to a plan review and inspection by the commissioner or an independent building inspector appointed by the commissioner. A fee shall be assessed for the cost of plan review and the cost of inspection. The commissioner may inspect an existing building that is undergoing renovation or remodeling to enforce the energy conservation requirements established under this chapter.

2. ~~Beginning on July 1, 2007, all~~ All newly constructed buildings, ~~excluding~~ including any addition, but excluding any renovation~~,~~ or repair of a building, ~~whether existing prior to July 1, 2007, or thereafter, that are~~ owned by the state board of regents shall be subject to a plan review and inspection by the commissioner or the commissioner's staff or assistant. ~~The commissioner and the state board of regents shall develop a plan to implement the requirements of this subsection, including funding recommendations related to plan review and inspection, by March 1, 2007.~~ The commissioner may inspect an existing building that is undergoing renovation or remodeling to enforce the energy conservation requirements established under this chapter. The commissioner and the state board of regents shall develop a plan to implement this provision.

Sec. 12. Section 103A.19, subsection 1, Code Supplement 2007, is amended to read as follows:

1. The examination and approval or disapproval of plans and specifications, the issuance and revocation of building permits, licenses, certificates, and similar documents, the inspection of buildings or structures, and the administration and enforcement of building regulations shall be the responsibility of the governmental subdivisions of the state and shall be administered and enforced in the manner prescribed by local law or ordinance. All provisions of law relating to the administration and enforcement of local building regulations in any governmental subdivision shall be applicable to the administration and enforcement of the state building code in the governmental subdivision. An application made to a local building department or to a state agency for permission to construct a building or structure pursuant to the provisions of the state building code shall, in addition to any other requirement, be signed by the owner or the owner's authorized agent, and shall contain the address of the owner, and a statement that the application is made for permission to construct in accordance with the provisions of the code. The application shall also specifically include a statement that the construction will be in accordance with all applicable energy conservation requirements.

Sec. 13. Section 103A.22, subsection 1, Code 2007, is amended to read as follows:

1. Nothing in this chapter shall be construed as prohibiting any governmental subdivision from adopting or enacting any building regulations relating to any building or structure within its limits, but a governmental subdivision in which the state building code has been accepted and is applicable shall not have the power to supersede, void, or repeal or make more restrictive any of the provisions of this chapter or of the rules adopted by the commissioner. This

subsection shall not apply to energy conservation requirements adopted by the commissioner and approved by the council pursuant to section 103A.8A or 103A.10.

Sec. 14. Section 216A.102, subsection 2, paragraph b, Code 2007, is amended by striking the paragraph.

Sec. 15. Section 266.39C, subsection 3, Code 2007, is amended to read as follows:

3. Iowa state university of science and technology shall employ a director for the center, who shall be appointed by the president of Iowa state university of science and technology. The director of the center shall employ necessary research and support staff. The director and staff shall be employees of Iowa state university of science and technology. ~~No more than seven hundred thousand dollars of the funds made available by appropriation from state revenues in any one year shall be expended by the center for the salaries and benefits of the employees of the center, including the salary and benefits of the director. The limit on expenditures for salaries and benefits shall be adjusted annually by a percentage equal to the average percentage salary adjustment approved annually by the state board of regents for professional and scientific employees at Iowa state university of science and technology. The remainder of the funds appropriated from state funds~~ Funds appropriated to the center shall be used to sponsor research grants and projects submitted on a competitive basis by Iowa colleges and universities and private nonprofit agencies and foundations, and for the salaries and benefits of the employees of the center. The center may also solicit additional grants and funding from public and private nonprofit agencies and foundations.

Sec. 16. Section 388.9, subsection 2, Code 2007, is amended by adding the following new unnumbered paragraph:

NEW UNNUMBERED PARAGRAPH. For purposes of this subsection, "proprietary information" includes customer records that if disclosed would harm the competitive position of a customer; or information required by a noncustomer contracting party to be kept confidential pursuant to a nondisclosure agreement which relates to electric transmission planning and construction, critical energy infrastructure, an ownership interest or acquisition of an ownership interest in an electric generating facility, or other information made confidential by law or rule.

Sec. 17. Section 455E.11, subsection 2, paragraph e, Code 2007, is amended by striking the paragraph.

Sec. 18. Section 473.1, Code 2007, is amended by adding the following new subsections:

NEW SUBSECTION. 0A. "Alternative and renewable energy" means the same as in section 469.31.

NEW SUBSECTION. 4A. "Renewable fuel" means the same as in section 469.31.

Sec. 19. Section 473.1, subsection 5, Code 2007, is amended to read as follows:

5. "Supplier" means any person engaged in the business of selling, importing, storing, or generating energy sources, alternative and renewable energy, or renewable fuel in Iowa.

Sec. 20. Section 473.2, subsection 1, paragraph a, Code 2007, is amended to read as follows:

a. Physical, human, natural, and financial resources are allocated efficiently.

Sec. 21. Section 473.3, Code 2007, is amended to read as follows:

473.3 ENERGY ~~EFFICIENCY~~ RESOURCE MANAGEMENT GOAL.

1. The goal of this state is to ~~more~~ efficiently utilize energy resources~~, especially those that are nonrenewable or that have negative environmental impacts, in order~~ to enhance the economy of the state ~~and to decrease~~ by decreasing the state's dependence on nonrenewable energy resources from outside the state and by reducing the amount of energy used. This goal is to be implemented through the development of policies and programs that promote energy efficiency, ~~and~~ energy conservation, and alternative and renewable energy use by all Iowans, through the development and enhancement of an energy efficiency and alternative and renewable energy industry, through the ~~development of indigenous~~ commercialization of energy resources and technologies that are economically and environmentally viable, and through the development and implementation of effective public information and education programs.

2. State government shall be a model and testing ground for the use of energy efficiency, energy conservation, and alternative and renewable energy systems.

Sec. 22. Section 473.7, subsections 2 and 3, Code Supplement 2007, are amended by striking the subsections.

Sec. 23. Section 473.7, subsections 4, 5, 11, 12, and 14, Code Supplement 2007, are amended to read as follows:

4. a. ~~Establish a central depository within the state for energy data. The central depository shall be located at or accessible through a library which is a member of an interlibrary loan program to facilitate access to the data and information contained in the central depository.~~ The department shall collect and analyze data ~~necessary to forecast~~ to use in forecasting future energy ~~demands in~~ demand and supply for the state. ~~The department may require a~~ A supplier is required to provide information pertaining to the supply, storage, distribution, and sale of energy sources in this state when requested by the department. The information ~~shall be furnished on a periodic basis,~~ shall be of a nature which directly relates to the supply, storage, distribution, and sale of energy sources, and shall not include any records, documents, books, or other data which relate to the financial position of the supplier. ~~Provided the~~ The department, prior to requiring any supplier to furnish it with such information, shall make every reasonable effort to determine if ~~the same~~ such information is available from any other governmental source. If it finds such information is available, the department shall not require submission of the ~~same~~ information from a supplier. Notwithstanding the provisions of chapter 22, information and reports obtained under this section shall be confidential except when used for statistical purposes without identifying a specific supplier and when release of the information will not give an advantage to competitors and serves a public purpose. The department shall use this data to conduct energy forecasts ~~which shall be included in the biennial update required by this section~~.

b. The department may subpoena witnesses, administer oaths, and require the production of records, books, and documents for examination in order to obtain information required to be submitted under this section. In case of failure or refusal on the part of any person to comply with a subpoena issued by the department, or in case of the refusal of any witness to testify as to any matter regarding which the witness may be interrogated under this chapter, the district court, upon the application of the department, may order the person to show cause why the person should not be held in contempt for failure to testify or comply with a subpoena, and may order the person to produce the records, books, and documents for examination, and to give testimony. The courts may punish for contempt as in the case of disobedience to a like subpoena issued by the court, or for refusal to testify.

5. Develop, recommend, and implement with appropriate agencies public and professional education and communication programs in energy efficiency, energy conservation, and conversion to ~~alternative sources of energy~~ alternative and renewable energy.

11. Develop, in coordination with the office of energy independence, a program to annually give public recognition to innovative methods of energy conservation, energy management, and alternative and renewable energy production.

12. Administer and coordinate, in coordination with the office of energy independence, federal funds for energy conservation, energy management, and alternative and renewable energy programs ~~including, but not limited to, the institutional conservation program, state energy conservation program, and energy extension service program, and related programs which provide energy management and conservation assistance to schools, hospitals, health care facilities, communities, and the general public~~.

14. ~~Perform~~ Provide information from monthly fuel surveys which establish a statistical average of motor fuel prices for various motor fuels provided throughout the state. Additionally, the department shall ~~perform~~ provide statewide monthly fuel ~~surveys in cities with populations of over fifty thousand~~ survey information which establish a statistical average of motor fuel prices for various motor fuels provided in ~~those individual cities~~ both metropolitan and rural areas of the state. The survey results shall be publicized in a monthly press release issued by the department.

Sec. 24. Section 473.15, Code 2007, is amended to read as follows:

473.15 ANNUAL REPORT.

The department shall ~~include in the~~ complete an annual report ~~required under section 455A.4 an assessment of~~ to assess the progress ~~achieved by public agencies~~ of state agencies in implementing energy management improvements, alternative and renewable energy systems, and life cycle cost analyses under chapter 470, and on the use of renewable fuels. The department shall work with state agencies and with any entity, agency, or organization with which they are associated or involved in such implementation, to use available information to minimize the cost of preparing the report. The department shall also provide an assessment of the economic and environmental impact of the progress made by state agencies related to energy management and alternative and renewable energy, along with recommendations on technological opportunities and policies necessary for continued improvement in these areas.

Sec. 25. Section 473.19, Code 2007, is amended to read as follows:

473.19 ENERGY BANK PROGRAM.

1. The energy bank program is established by the department. The energy bank program consists of the following forms of assistance for the state, state agencies, political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations:

~~1.~~ a. Promoting program availability.

b. Developing or identifying guidelines and model energy techniques for the completion of energy analyses for state agencies, political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations.

c. Providing ~~moneys from the petroleum overcharge fund~~ technical assistance for conducting or evaluating energy ~~audits~~ analyses for ~~school districts under section 279.44, for conducting comprehensive engineering analyses for school districts and for conducting energy audits and comprehensive engineering analyses for state agencies, and political subdivisions of the~~ state agencies, political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations.

~~2.~~ d. Providing or facilitating loans, leases, and other methods of alternative financing ~~from~~ under the energy loan ~~fund established in section 473.20 and section 473.20A~~ program for the state, state agencies, political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations to implement energy ~~conservation measures~~ management improvements or energy analyses.

~~3. Serving as a source of technical support for energy conservation management.~~

~~4.~~ e. Providing assistance for obtaining insurance on the energy savings expected to be realized from the implementation of energy ~~conservation measures~~ management improvements.

~~5.~~ f. ~~Providing~~ Facilitating self=liquidating financing for the state, state agencies, political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations pursuant to section 473.20A.

g. Assisting the treasurer of state with financing agreements entered into by the treasurer of state on behalf of state agencies to finance energy management improvements pursuant to section 12.28.

2. For the purpose of this section, section 473.20, and section 473.20A, "energy ~~conservation measure"~~ management improvement" means construction, rehabilitation, acquisition, or modification of an installation in a facility or vehicle which is intended to reduce energy consumption, or energy costs, or both, or allow the use of ~~an alternative energy source, which may contain integral~~ alternative and renewable energy. "Energy management improvement" may include control and measurement devices. "Nonprofit organization" means an organization exempt from federal income taxation under section 501(c)(3) of the Internal Revenue Code.

3. The department shall submit a report by January 1 annually to the governor and the general assembly detailing services provided and assistance rendered pursuant to the energy bank program and pursuant to sections 473.20 and 473.20A, and receipts and disbursements in relation to the energy bank fund created in section 473.19A.

4. Moneys awarded or allocated to the state, its citizens,

or its political subdivisions as a result of the federal court decisions and United States department of energy settlements resulting from alleged violations of federal petroleum pricing regulations attributable to or contained within the Stripper Well fund shall be allocated to and remain under the control of the department for utilization for energy program=related staff support purposes.

Sec. 26. NEW SECTION. 473.19A ENERGY BANK FUND.

1. The energy bank fund is created within the state treasury under the control of the department, in collaboration with the office of energy independence established in section 469.2. The fund shall be used for the operational expenses and administrative costs incurred by the department in facilitating and administering the energy bank program established in section 473.19.

2. The energy bank fund shall consist of amounts deposited into the fund or allocated from the following sources:

a. Any moneys awarded or allocated to the state, its citizens, or its political subdivisions as a result of the federal court decisions and United States department of energy settlements resulting from alleged violations of federal petroleum pricing regulations attributable to or contained within the Exxon fund. Amounts remaining in the oil overcharge account established in section 455E.11, subsection 2, paragraph "e", and the energy conservation trust established in section 473.11, as of June 30, 2008, shall be deposited into the energy bank fund pursuant to this paragraph, notwithstanding section 8.60, subsection 15.

b. (1) Moneys received in the form of fees imposed upon the state, state agencies, political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations for services performed or assistance rendered pursuant to the energy bank program. Fees imposed pursuant to this paragraph shall be established by the department in an amount corresponding to the operational expenses or administrative costs incurred by the department in performing services or providing assistance authorized pursuant to the energy bank program, as follows:

(a) For a building of up to twenty=five thousand square feet, two thousand five hundred dollars.

(b) For a building in excess of twenty=five thousand square feet, an additional eight cents per square foot.

(c) A building that houses more energy intensive functions may be subject to a higher fee than the fees specified in subparagraphs (a) and (b) as determined by the department.

(2) Any fees imposed shall be retained by the department and are appropriated to the department for purposes of providing the services or assistance under the program.

c. Moneys appropriated by the general assembly and any other moneys, including grants and gifts from government and nonprofit organizations, available to and obtained or accepted by the department for placement in the fund.

d. Moneys contained in the intermodal revolving loan fund administered by the department of transportation for the fiscal year beginning July 1, 2019, and succeeding fiscal years.

e. Moneys in the fund are not subject to section 8.33. Notwithstanding section 12C.7, interest or earnings on moneys in the fund shall be credited to the fund.

3. The energy bank fund shall be limited to a maximum of

one million dollars. Amounts in excess of this maximum limitation shall be transferred to and deposited in the rebuild Iowa infrastructure fund created in section 8.57, subsection 6.

Sec. 27. Section 473.20, unnumbered paragraph 1, Code 2007, is amended to read as follows:

An energy loan ~~fund~~ program is established ~~in the office of the treasurer of state to~~ and shall be administered by the department.

Sec. 28. Section 473.20, subsections 1, 5, and 6, Code 2007, are amended to read as follows:

1. The department may ~~make loans to the state, state agencies,~~ facilitate the loan process for political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations for implementation of energy ~~conservation measures~~ management improvements identified in ~~a comprehensive engineering~~ an energy analysis. Loans shall be ~~made~~ facilitated for all cost=effective energy management improvements. For ~~the state, state agencies,~~ political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations to receive ~~a~~ loan ~~from the fund~~ assistance under the program, the department shall require completion of an energy management plan including an energy ~~audit and a comprehensive engineering~~ analysis. The department shall approve loans ~~made~~ facilitated under this section.

5. ~~The state, state agencies, political~~ Political subdivisions of the state, school districts, area education agencies, and community colleges shall design and construct the most energy cost=effective facilities feasible and ~~shall use the financing made available~~ may use financing facilitated by the department to cover the incremental costs above minimum building code energy efficiency standards of purchasing energy efficient devices and materials unless other lower cost financing is available. As used in this section, "facility" means a structure that is heated or cooled by a mechanical or electrical system, or any system of physical operation that consumes energy to carry out a process.

6. The department shall not require the state, state agencies, political subdivisions of the state, school districts, area education agencies, and community colleges to implement a specific energy ~~conservation measure~~ management improvement identified in ~~a comprehensive engineering~~ an energy analysis if the entity which prepared the analysis demonstrates to the department that the facility which is the subject of the energy ~~conservation measure~~ management improvement is unlikely to be used or operated for the full period of the expected savings payback of all costs associated with implementing the energy ~~conservation measure~~ management improvement, including without limitation, any fees or charges of the department, engineering firms, financial advisors, attorneys, and other third parties, and all financing costs including interest, if financed.

Sec. 29. Section 473.20, subsection 3, Code 2007, is amended by striking the subsection.

Sec. 30. Section 473.20A, Code 2007, is amended to read as follows:

473.20A SELF=LIQUIDATING FINANCING.

1. The department of natural resources may ~~enter into~~

facilitate financing agreements that may be entered into with ~~the state, state agencies,~~ political subdivisions of the state, school districts, area education agencies, community colleges, or nonprofit organizations ~~in order to provide the financing~~ to ~~pay~~ finance the costs of ~~furnishing~~ energy ~~conservation measures~~ management improvements on a self=liquidating basis. The provisions of section 473.20 defining eligible energy ~~conservation measures and the method of repayment of the loans~~ management improvements apply to financings under this section.

The financing agreement may contain provisions, including interest, term, and obligations to make payments on the financing agreement beyond the current budget year, as may be ~~agreed upon between the department of natural resources and the state, state agencies,~~ acceptable to political subdivisions of the state, school districts, area education agencies, community colleges, or nonprofit organizations.

~~2. For the purpose of funding its obligation to furnish moneys under the financing agreements, or to fund the energy loan fund created in section 473.20, the treasurer of state, with the assistance of the department of natural resources, or the treasurer of state's duly authorized agents or representatives, may incur indebtedness or enter into master lease agreements or other financing arrangements to borrow to accomplish energy conservation measures, or the department of natural resources may enter into master lease agreements or other financing arrangements to permit the state, state agencies, political subdivisions of the state, school districts, area education agencies, community colleges, or nonprofit organizations to borrow sufficient funds to accomplish the energy conservation measure. The obligations may be in such form, for such term, bearing such interest and containing such provisions as the department of natural resources, with the assistance of the treasurer of state, deems necessary or appropriate. Funds remaining after the payment of all obligations have been redeemed shall be paid into the energy loan fund.~~ The department shall assist the treasurer of state with financing agreements entered into by the treasurer of state on behalf of state agencies pursuant to section 12.28 to finance energy management improvements being implemented by state agencies.

~~3.~~ 2. ~~The state, state agencies, political~~ Political subdivisions of the state, school districts, area education agencies, community colleges, and nonprofit organizations may enter into financing agreements and issue obligations necessary to carry out the provisions of the chapter. Chapter 75 shall not be applicable.

Sec. 31. Section 476.46, subsection 2, paragraph d, subparagraph (2), Code 2007, is amended to read as follows:

(2) A facility shall be eligible for no more than ~~two hundred fifty thousand~~ one million dollars in loans outstanding at any time under this program.

Sec. 32. Sections 473.11, 473.13, 473.16, 473.17, 473.42, and 473.44, Code 2007, are repealed.

Sec. 33. EFFECTIVE DATE. This Act, being deemed of immediate importance, takes effect upon enactment.

JOHN P. KIBBIE

President of the Senate

PATRICK J. MURPHY
Speaker of the House

I hereby certify that this bill originated in the Senate and is known as Senate File 517, Eighty=second General Assembly.

MICHAEL E. MARSHALL
Secretary of the Senate

Approved _______________, 2008

CHESTER J. CULVER
Governor

CSEM

Center for the Study of Energy Markets

CSEM WP 115

Who Should Administer Energy-Efficiency Programs?

Carl Blumstein, Charles Goldman, Galen Barbose

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Who Should Administer Energy-Efficiency Programs?

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Abstract

The restructuring of the U.S. electricity industry created a crisis for ratepayer-funded energy-efficiency programs. This paper briefly describes the reasons for the crisis and some of its consequences. Then the paper focuses on issues related to program administration and discusses the relative merits of entities—utilities, state agencies, and non-profit corporations—that might be administrators. Four criteria are developed for choosing among program administration options: compatibility with public policy goals, effectiveness of the incentive structure, ability to realize economies of scale and scope, and contribution to the development of an energy-efficiency infrastructure. We examine one region, the Pacific Northwest, and three states, New York, Vermont, and Connecticut, which have made successful transitions to new governance and/or administration structures. Attention is also given to California where large-scale energy-efficiency programs have continued to operate, despite the fact that many of the key governance/administration issues remain unresolved.

We observe that no single administrative structure for energy-efficiency programs has yet emerged in the US that is clearly superior to all of the other alternatives. We conclude that this is not likely to happen soon for three reasons. First, policy environments differ significantly among the states. Second, the structure and regulation of the electric utility industry differs among the regions of the US. Third, market transformation and resource acquisition, two program strategies that were once seen as alternatives, are increasingly coming to be seen as complements. Energy-efficiency programs going forward are likely to include elements of both strategies. But, the administrative arrangements that are best suited to support market transformation may be different from the arrangements that are best for resource acquisition.

Keywords: energy-efficiency, restructuring, administration.

1. Introduction

Proponents of energy efficiency received the Energy Policy Act (EPACT), passed by the US Congress in 1992 (P. L. 102-486), with satisfaction because of provisions in the Act that encouraged utilities to conduct Integrated Resource Planning.[1] Integrated Resource Planning, also known as Least-Cost Planning, is a process in which utilities plan for the future needs of their customers by considering and assessing benefits and costs to society, the utility, and customers of a broad range of resource options including new generation, transmission capacity, and demand-side alternatives. In the Integrated Resource Planning context, energy-efficiency programs were seen as one mechanism for ensuring that the supply of electricity was adequate.

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[1] Provisions in Title 1, Subtitle B of EPACT required state regulatory commissions to consider directing utilities under their jurisdictions to employ Integrated Resource Planning. Non-regulated utilities also had to consider using Integrated Resource Planning.

The archetypal efficiency program under Integrated Resource Planning was one in which a utility's customers were provided with technical assistance, information, and financial incentives to purchase or invest in energy-efficient building materials (e.g., additional insulation), equipment (e.g., high-efficiency chillers), or appliances (e.g., buying more efficient refrigerators) (Eto, 2001). Such programs were commonly referred to as "resource acquisition" programs because they were expected to meet the demand for energy services at a cost that was lower than the cost of acquiring generation resources (NARUC, 1988).

But EPACT also contained provisions that enabled restructuring of the electricity industry in the US and significantly diminished the importance of Integrated Resource Planning in the regulatory agenda.[2] In the US, expenditures for utility energy-efficiency programs peaked at $1.7 billion in 1993-94. But expenditures began a steep decline in many states after the California Public Utilities Commission (CPUC) announced in April 1994 that it intended to restructure California's electricity industry.[3]

Restructuring in the US was premised in part on the belief that formal resource planning processes that authorized or approved acquisition of supply- and demand-side resources by state-regulated utilities would not be necessary because market outcomes would be better than the outcomes from plans developed by utilities and regulators. Generation, transmission, and distribution were to be unbundled and no firm or agency was to be responsible for assuring supply. Interactions among buyers and sellers in a competitive wholesale electricity market were expected to provide the right balance of supply and demand. In those states with retail competition, distribution utilities typically no longer had the "obligation to serve" for all customers, which meant that there was no place in the restructured electricity industry for Integrated Resource Planning and the attendant acquisition of energy efficiency as a resource.[4]

Although the rationale for resource acquisition was weakened or eliminated in states that restructured, the underlying reasons for public support of energy efficiency did not disappear. Restructuring did not eliminate most of the externalities and other market failures that energy-efficiency programs were intended to address. These externalities and other market failures provided the rationale for continued support of energy-efficiency programs after restructuring (Blumstein et al., 1980; Golove and Eto, 1996; Vine et al., 2003).

As a consequence, a different program strategy, "market transformation," was introduced in many states that typically supplemented existing objectives or, in a few states, became the primary objective of energy efficiency programs. State policymakers articulated this objective of transforming energy service markets in various ways: "the mission of market transformation is to ultimately privatize the provision of cost-effective energy efficiency services" (California); "[the goal is] facilitating the transformation of markets so that they effectively respond to customers' needs and public interests in increased energy

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[2] Provisions in Title 7 of EPACT were intended to increase competition in the electric generating sector by creating new entities, called "exempt wholesale generators" (EWGs), that could generate and sell electricity at wholesale without being regulated as utilities under the Public Utilities Holding Company Act of 1935. This title also provided EWGs with a way to assure transmission of their wholesale power to its purchaser.

[3] Energy efficiency spending in the US reached a low point of $918 million in 1997, a drop of almost 50% compared to 1993 spending. Spending has since increased, rebounding to $1.1 billion in 2000 (York and Kushler 2002).

[4] With restructuring, transmission system planning is increasingly being done by regional ISOs rather than utilities; ISO plans typically provide information to the market on system resource needs, rather than pre-approve a set of resources that can either be built or acquired by the utility.

efficiency" (Wisconsin); "market transformation efforts are designed to create long-term changes that reap continuous energy efficiency savings at low cost" (Massachusetts); "[energy-efficiency program]funds should be targeted towards programs that emphasize permanently transforming the market for energy efficient products and services or reducing market barriers, rather than achieving immediate or customer-specific savings" (New York) (quotations from material in Eto et al., 1998).

As can be seen from the above statements, market transformation encompasses several themes. It is a broad umbrella under which many activities may be undertaken. Market transformation emphasizes making lasting changes in markets for energy-consuming goods and services (Keating et al., 1998; Blumstein et al., 2000). This is different from resource acquisition, which emphasizes obtaining savings from individual consumers by subsidizing energy-efficiency measures at the consumers' premises.[5] Examples of market transformation efforts include encouraging retailers, distributors, contractors, and builders to change their business models to promote energy efficiency. Other market transformation activities have targeted education and training efforts at key consumer and business decision points such as the replacement of existing appliances or equipment and the remodeling of buildings with the goal of influencing purchasing decisions for long-lifetime products and building environments.

Restructuring also called into question the mechanism for funding energy-efficiency programs. Before restructuring, when the utilities were vertically integrated monopolies, regulators simply ordered the utilities to include program costs in the utilities' rates. After restructuring there was concern that including program costs in rates might place the incumbent utilities at a competitive disadvantage—customers might avoid the charge by switching to a new competing supplier. This problem was addressed by creating "non-bypassable" charges. In the ~20 states that restructured, most energy-efficiency programs are now funded by ratepayers through a separate "public benefit fund" or "system benefit charge" included in their bill from the (still) monopoly distribution utility.

The result of these changes in program rationale and funding mechanism was that US states began experimenting with a variety of administrative and governance arrangements. While this experimentation is continuing, the disastrous collapse of the electricity market in California in the winter of 2000-2001 (Blumstein et al., 2002) has greatly altered the regulatory landscape in California and other states. When the California electricity market collapsed, leading to system emergencies and power outages, energy-efficiency programs in California shifted emphasis and funding towards programs and activities that produced quick, near-term electricity and summer peak demand savings with some success (Goldman et al., 2002). With the suspension of retail competition, California utilities are again being asked to take responsibility for assuring the adequacy of supply, which includes assessment and procurement of generation and demand-side resource options. In states such as New York and Connecticut where state regulators are still pursuing policies that facilitate wholesale and retail competition, the new energy-efficiency program administrators have adapted their programs to meet pressing state and regional needs. For example, there have been efforts to dampen wholesale price volatility by reducing peak demand in tight supply markets and efforts to mitigate transmission constraints by targeting energy-efficiency and load management to "load pockets" such as in Southwest Connecticut or downstate New York. In the Pacific Northwest with its energy-constrained, hydro-based system, policymakers have created a regional energy-efficiency administrator that takes a longer-term market transformation

[5] The two strategies are not mutually exclusive; they can be pursued simultaneously. The distinction between the strategies is useful for the analysis of options for program administration, but in practice the distinction is not always as sharp as it is drawn here.

perspective as well as resource acquisition programs that are administered by a non-profit corporation in Oregon and utilities in Washington.

In this paper we examine some of the questions that are important for the administration of energy-efficiency programs in the new regulatory environment. What are the key factors and criteria to consider in choosing among different types of entities to administer, design and implement programs? What were the key drivers for policymakers in various states in selecting among alternative administration and governance structures? What should and can policymakers do to ensure that the strategies and activities of ratepayer-funded energy-efficiency programs contribute to the long-term development of an energy-efficiency services infrastructure?

2. Administrative Options

Prior to restructuring in the US, the administration, design, and delivery of ratepayer-funded energy-efficiency program activities was largely the responsibility of utilities, operating within the context of an Integrated Resource Planning process that was overseen and governed by state regulators. Most states that restructured their electricity sector re-evaluated the administration and governance of energy-efficiency programs, trying to find the structures that were best suited for the new policy environment. In some states, alternative structures have evolved in which program administration and governance have been taken over by non-utility entities, such as existing state governmental agencies, or non-profit corporations with boards of directors.

In assessing the relative merits of administrative structures, policymakers and regulators must evaluate the trade-offs involved with working with single-purpose vs. multi-purpose organizations. The core mission of utilities typically involves the reliable, efficient delivery of electric power to end users (and may include power generation). Some utilities also view energy-efficiency programs as a core part of their customer services activities. However, regulators recognize that utilities often have financial disincentives to promote customer load reductions, given that electricity sales are the main source of their revenues and profits. As such, utilities are multi-purpose organizations. Policymakers must weigh the benefits that derive from utilities' trusted position with customers and market entities, their economies of scale and scope, and their experience against their perceived conflicts of interest in administering energy-efficiency programs.

State agencies, as parts of state governments that have many responsibilities, are also, in effect, multi-purpose organizations. When considering state agencies as candidates to administer a public-purpose energy-efficiency program, policymakers must weigh the potential benefits of an administrator without perceived conflicts of interest against the potential problems of state government administration. Examples of these potential problems include difficulties agencies may have in focusing on a new mission, constraints imposed by staffing limitations or bureaucratic procurement requirements, challenges of providing effective incentives for state agencies, and the potential for sub-optimal allocation of funds or mix of programs due to political pressures.

Non-profit energy efficiency corporations with boards of directors are typically single-purpose organizations whose sole mission is delivery of energy-efficiency programs. Policymakers must weigh this alignment of administrator objectives/mission with public policy against the challenges of creating an acceptable governance mechanism (for example, a board that balances stakeholder interests or novel arrangements for regulatory oversight) and establishing a well respected, trusted administrator with a significantly expanded scope of activities for existing staff or creating a new organization.

The delivery of energy-efficiency programs involves a diverse set of responsibilities that can be grouped according to several core functions (Table 1). There is some degree of overlap among the functions and responsibilities. For example, program design falls within the domain of Program Development, Planning, and Budgeting, as well as Program Administration and Management.

This paper focuses on the entity that maintains primary responsibility and accountability for the proper use of the public or ratepayer funds supporting the programs (General Administration and Coordination in Table 1). But this entity, which we call the energy-efficiency program administrator, need not (indeed, typically does not) perform all the functions in Table 1. The division of responsibilities may be left to the energy-efficiency program administrator or policymakers may prescribe it.

In regions where market transformation and building private sector infrastructure are priorities for policymakers, a very large portion of the responsibilities in Table 1 may be contracted out as a means of building private sector infrastructure. Other entities, including private firms, can participate at many levels within the program delivery chain: at the program portfolio level, the individual program level, the project level, or for specific implementation functions (e.g., program design, energy auditing, measurement and verification services, program evaluation, etc.). These arrangements may be established through competitive solicitation, such as demand-side management bidding programs, where a request for proposals is issued for energy-efficiency projects to deliver some specified amount of energy or demand savings. Or alternatively, they may be based on a partnership arrangement, such as with industry or vendor trade associations (e.g., for information campaigns), academic institutions, etc. Ultimately, the administrative structure itself, and the nature of the relationships among the institutions involved will be dictated by a host of factors.

Table 1
Elements of Energy-Efficiency Program Administration and Delivery

Program Function	Specific Responsibilities
General Administration and Coordination	• Manage overall budget for portfolio of programs • Manage contracts with all primary contractors • Maintain centralized information system for reports to regulators, legislators, advisory groups, etc.
Program Development, Planning, and Budgeting	• Prepare initial technical and/or market reports necessary for program strategies and initial program designs • Facilitate development of public planning process • Prepare general program descriptions and budgets for regulatory approval
Program Administration and Management	• Prepare detailed program designs and propose changes based on experience-to-date • Hire and manage staff and/or sub-contractors for program implementation • Develop and implement quality assurance standards and tracking protocols • Review and approval of invoices
Program Delivery and Implementation	• Promote and market programs • Develop and implement program services (e.g., energy audits, financial incentives, contractor certification, information and education, etc.) • Develop energy-efficiency projects at specific sites • Develop measurement and verification (M&V) procedures and/or conduct M&V to determine performance-based administration fees or shareholder incentives
Program Assessment and Evaluation	• Assess program impacts and/or cost-effectiveness • Evaluate effectiveness of program processes and administration

3. What criteria need to be considered in choosing an administrator?

In this section we examine several criteria that need to be considered in creating the administrative structure for energy-efficiency programs.[6] These criteria are compatibility with public policy goals, effectiveness of the incentive structure, ability to realize economies of scale and scope, and contribution to the development of the energy-efficiency infrastructure.

Compatibility with public policy goals. This criterion includes several subsidiary criteria, which are of two types. The first type is "good-governance" criteria that might apply to any publicly funded organization and include legitimacy, accountability and resiliency. By legitimacy we mean that the energy-efficiency program administrator is established in a way that forestalls challenges to the organization's right to act. This might be achieved by a legislative mandate or a consensus among stakeholders. Accountability requires reviews of the administrator's performance in achieving goals and mechanisms for correcting poor performance.[7] Resiliency means the ability of the administrator to adapt quickly to changing circumstances, including changing public policy goals.

The second type of criteria is related to either broader electricity market or energy-efficiency specific policy goals articulated by state policymakers. For example, electricity restructuring led many states to adopt policies that encouraged or compelled utilities to divest generation assets, encouraged the entry of competitive retail energy suppliers, and created new institutions to administer the transmission grid. What remained of the utilities were distribution companies under state regulation. In this market structure, energy services were to be provided primarily by the competitive providers, including those affiliated with utilities. Thus, policymakers increasingly considered such factors as ability to foster provision of energy-efficiency services by the competitive market and were concerned about the role and influence of the energy-efficiency program administrator on competition among retail electricity suppliers. In other cases, the public policy goals were focused primarily on energy-efficiency objectives, such as the capability of the administrator to support market transformation goals. Specifically, if the program is focused on achieving market transformation objectives, then it is particularly important for the administrator to have comprehensive knowledge of the retail energy and energy-efficiency markets, have the ability to quickly ramp up and down program initiatives, and to have flexible contracting and procurement processes.

Effectiveness of the incentive structure. Incentives have been an issue from the inception of utility-administered energy-efficiency programs. After years of command and control regulation, many policymakers in the US concluded that incentive mechanisms were needed both to reward performance in delivering energy-efficiency resources and to address disincentives that were inherent in rate-of-return regulation. For most utilities under rate-of-return regulation, profits in the short run increased with increasing sales. Thus, utilities actually had a disincentive for effective program administration. Before restructuring, regulators in some states dealt with this issue by creating rate designs that made utility profits independent of sales, and many state PUCs offered financial

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[6] Two other papers that address criteria are Eto et al. (1998) and Didden and D'haeseleer (2003). Eto et al. (1998), written when confidence in restructuring was very high, provided the starting point for the criteria that are developed here. Didden and D'haeseleer (2003), which addresses the implementation of energy efficiency programs in the European context, focuses on isssues related to the incentive structure.

[7] For regulated utilities, regulators have the authority to investigate and assess disallowances or penalties for poor or non-performance. In cases where energy efficiency program administrators have established a contractual relationship (e.g., non-profit corporation), the governing agency's primary mechanism to discourage poor performance is the possibility of contract termination or failure to renew.

incentives to shareholders based on performance in delivering cost-effective energy-efficiency programs. Because the purpose of the energy-efficiency programs was resource acquisition, the incentive payments were typically based on measurements of the energy savings and/or net benefits directly attributable to the programs.

When the policy agenda shifted in some states from resource acquisition to market transformation, the problem of incentives became, in some ways, more complicated. First, the effectiveness of market transformation programs and activities are more difficult to measure than the effectiveness of resource acquisition programs. Second, traditional incentive mechanisms used to motivate utilities—that is, "mark-up", "shared savings", and "bonus" based on net societal benefits (Stoft and Gilbert, 1994)—were less applicable to the new entities under consideration for energy-efficiency program administration (i.e., non-profit organizations, and state agencies). Third, because it typically takes at least several years to observe and assess market transformation impacts, it is preferable to develop performance incentives based on multi-year program and evaluation periods. Fourth, the trend toward "outsourcing" program implementation to for-profit or non-profit corporations has meant that policymakers have had to consider structuring performance incentives for program implementers and the extent to which energy efficiency program administrators should be held accountable for the performance of program implementers.

Evaluation of the incentive structure should go beyond consideration of financial incentives and disincentives for organizations. Intra-organization factors should also be considered. These factors include the ability of organization to offer sufficient compensation to attract skilled personnel and to provide them with opportunities for advancement when they perform well. Civic motivations, such as a desire to contribute to a sustainable future, are often important to personnel involved in conducting energy-efficiency programs. The degree to which civic motivations are respected and contributions to civic goals are recognized is an important part of the incentive structure.

<u>Ability to realize economies of scale and scope.</u> Prior to restructuring, utilities seemed the obvious choices for administrators of energy-efficiency programs because they were responsible for resource acquisition of all types and had well-established relationships with the customers from whom efficiency resources were to be acquired. When resource acquisition is the primary program objective there are no obvious economies of scale beyond the need to be large enough to maintain an effective professional staff.

The situation is different if market transformation is the sole or primary program objective. Markets often extend beyond the boundaries of a single utility's service territory, and thus it is often more appropriate to conduct market transformation programs on a statewide, multi-state regional, national, or even international basis. Quite substantial resources may be required to have a significant market impact; efforts that are undertaken on too small a scale may dissipate resources without any impact.

When resource acquisition and market transformation are both important program objectives, there are likely to be gains from coordination. An example of coordination might be a resource acquisition program offering rebates to customers for the purchase of efficient washing machines that is coordinated with a market transformation program that encourages dealers to stock efficient washing machines. Although coordination does not require that both types of activities be administered by the same organization, the gains from coordination create an economy of scope since intra-organization coordination is typically easier than inter-organization coordination.

<u>Contribution to the development of the energy-efficiency infrastructure.</u> In the initial enthusiasm for restructuring and expectations for the effectiveness of markets in the electricity sector, some policymakers concluded that ratepayer-funded energy-efficiency programs were transient phenomena. In this view, government intervention would only

be needed for a short transition period, after which the competitive retail market would provide robust energy-efficiency service offerings to all customer classes and market segments. This view now seems overly optimistic (Kushler and Witte, 2001). An alternative view is that the externalities and other market failures that are the underlying justification for energy-efficiency programs are going to be with us for the foreseeable future. In this view a steady improvement in energy efficiency – that is, a steady reduction in the energy intensity of the economy (Rosenfeld et al., 2001) – is at least part of the path to a sustainable future. To accomplish this end it will be necessary to build an energy-efficiency services infrastructure that is capable of sustaining a steady reduction in energy intensity over the long term. This requires, at a minimum, greater stability and predictability in public support for energy efficiency. During the era of Integrated Resource Planning, funding levels for energy efficiency varied significantly over time depending on the utility's overall load/resource balance, forecast of avoided costs, and regulator's concerns about rate impacts. With passage of legislation or regulations that typically authorize specified levels of public benefit funding, the largest uncertainties are the duration of funding (e.g., sunset provisions in legislation) and the mix and allocation of program funds. The recent spate of state budget crises has added to the uncertainty about the duration of funding: some state legislatures are now considering appropriating public benefits funds to the states' general funds to cover revenue shortfalls.

The issue of how best to build and sustain an energy-efficiency services infrastructure is directly related to the roles and responsibilities provided by energy-efficiency program administrators. Should the energy-efficiency program administrator be an institutional home for "human capital" (that is, people with the expertise needed to develop, design and implement energy-efficiency programs)? Or, should the energy-efficiency program administrator be only a "funding agent" whose primary role is outsourcing programs in order to foster the development of private sector firms, non-profits, and other institutions that support energy efficiency?

Institution building is a significant challenge, either in terms of retaining the capability of existing institutions or creating new institutions that are sustainable over the long term. In the US, policymakers have considered such issues as the potential value and/or loss of existing energy-efficiency expertise and resources of utilities, the linkages among incumbent energy-efficiency program administrators and the broader network of energy-efficiency service providers, and the ability of different types of energy-efficiency program administrators to attract highly qualified and motivated administrative and technical personnel.

4. Energy Efficiency Program Administration and Experience in the US

As states in the US have restructured their electricity sectors, a range of different approaches has been adopted for the administration and governance of energy-efficiency programs. Some states have opted to continue using the utilities as primary administrators, while other states shifted some or all of that responsibility to state agencies or nonprofit organizations. Five states/regions, discussed below, provide specific examples of the types of administrative approaches that have been adopted and the issues that these approaches have sought to address (Table 2).

4.1 Pacific Northwest

Energy-efficiency programs in the Pacific Northwest (Oregon, Washington, Montana, and Idaho) are administered by a combination of regional and state-based organizations (see Figure 1, which uses Oregon as an example). The regional energy-efficiency program administrator is a non-profit organization, called the Northwest Energy Efficiency Alliance ("the Alliance"). Programs offered by the Alliance are all strongly geared towards market transformation (for example, marketing support for new energy-efficient products and efforts aimed at influencing market intermediaries that are "upstream" of the customer such as retailers, builders, and contractors). The Alliance is governed by a board of directors, which includes representatives of public and investor-owned utilities, BPA, state governments, and consumer groups. Funding is provided by the investor-owned and public utilities, the Energy Trust of Oregon (a non-profit corporation administering programs in Oregon), and the Bonneville Power Administration (BPA)—each of which use the Alliance to fulfill their organization's market transformation goals. For example, in 2003 BPA is spending $138 million on energy efficiency, $10 million of which goes to the Alliance to fund market transformation efforts (Keating, 2003). The Alliance programs are then augmented by a

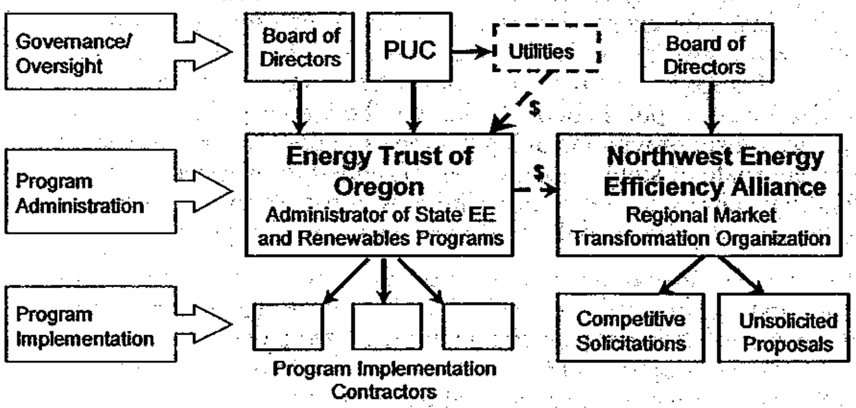

Fig. 1. Energy Efficiency Program Administration and Governance in Oregon and the Pacific Northwest

variety of more traditional local resource acquisition programs administered by individual utilities in Washington, Idaho, Montana, the Energy Trust of Oregon, and BPA.

The Alliance was born out of a long-term resource plan by the Northwest Power Planning Council, which called for a coordinated and sustained effort to build the market for energy-efficiency services and products in the region, as a strategy for offsetting a portion of the projected growth in electricity demand. Historically, energy-efficiency resource acquisition programs had been funded and administered by BPA, a number of large investor-owned utilities, and hundreds of small public utilities. The region's policymakers decided that this administrative structure was sub-optimal for their new market transformation objectives and also resulted in relatively high administrative costs. Thus, a fundamental rationale for creating a regional non-profit corporation to administer market transformation programs was to capture the economies of scale necessary for reducing administrative costs and providing a consistent signal to market actors and customers in a multi-state region.

While the scale of the Alliance is multi-state, the scope is narrow. The Alliance focuses on market assessment, program design, and project development, but does only a very limited amount of program implementation. The defining feature of the Alliance, as an organization that manages and oversees energy-efficiency programs aimed at market transformation, is the degree to which its activities are guided consciously and explicitly by the goal of building the capabilities of other organizations in the region.

The Alliance has a small, highly trained and experienced professional staff that is strongly motivated by civic concerns. The Alliance does not have any explicit financial incentives for good organizational performance. But, as a single-purpose organization dependent on the goodwill of numerous stakeholders, good performance is probably necessary for long-term survival.

In Oregon, the efforts of the Alliance are complemented by the recently formed Energy Trust of Oregon, which is a non-profit organization established to direct the public benefit funds for energy-efficiency and renewable energy programs in the state. Energy-efficiency programs in Oregon were previously administered by the utilities, but restructuring legislation passed in 1999 granted the authority to the Oregon PUC to select an alternative program administrator. In many ways, the administrative and governance model of the Energy Trust of Oregon is patterned after the Alliance. The Oregon PUC and the Energy Trust of Oregon signed a grant agreement, which codifies their contractual relationship, builds in significant accountability (e.g., periodic outside audits, review of contracts, composition of board of directors) and provides broad policy direction and review and approval of long-term strategic plans by the Oregon PUC. In return, the Energy Trust of Oregon is given significant flexibility to achieve the five long-term goals in its Strategic Energy Plan.

Thus, in the Pacific Northwest, policymakers have made a long-term public policy commitment to sustain energy efficiency as an environmentally benign resource that can dampen load growth in a hydro-based system. Given their emphasis on long-term sustainability of energy-efficiency infrastructure and services, they have opted to use single purpose, non-profit organizations with broad geographic reach to administer regional energy-efficiency programs. Key to the success of this approach thus far has been the compatibility of energy-efficiency program administrators in the Pacific Northwest with public policy goals. The administrators have demonstrated the legitimacy, accountability, and resiliency of their organizations and the Alliance has achieved market transformation goals in specific markets (NEEA, 2002b).

4.2 California

Energy-efficiency programs in California are currently administered by the state's four large investor-owned utilities. Energy-efficiency public benefits programs are funded through a non-bypassable surcharge on customers' utility bills, established through state legislation, which provides approximately $275 million annually for electric and natural gas energy-efficiency programs.[8] Oversight of program design and budgeting and review of program performance is conducted through regulatory proceedings of the California Public Utilities Commission (CPUC), where members of the public and other stakeholder groups can provide input and recommendations to the CPUC on the utility's proposed program plan, budget, and incentive mechanism for rewarding their performance.

Since the onset of restructuring, California policymakers have devoted significant time and attention to program administration, as it has been a very contentious issue. Initially, legislation only provided funding for four years. In 1997 the primary policy objective of the CPUC was to cultivate a self-sustaining market for energy-efficiency services so that significant public funding would not be needed after 2002. Compatibility with this policy goal required that any potential conflicts of interest related to the unregulated utility-affiliated companies be addressed. There was therefore a desire to move toward "independent" administration of the public benefits funded energy-efficiency programs. The CPUC created an advisory board, the California Board for Energy Efficiency (CBEE), whose mission was to facilitate the selection of an independent administrator and make recommendations regarding utility program designs and budgets to achieve the CPUC's market transformation objectives (CPUC, 1998). Working with the utilities and other interested parties, the CBEE recommended, and the CPUC adopted, major changes

[8] Customers of municipal utilities (about 25% of electricity sales) are exempt from this charge since municipal utilities are required to fund and operate their own programs.

in energy efficiency programs in various markets which led to innovative statewide programs in new construction, residential appliance, and commercial and industrial markets. However, the objective of restructuring program administration conflicted with the objective of phasing out program funding in only a few years. It was a tumultuous period for the utility program administrators; day-to-day program operations undoubtedly suffered as a result.

In 2000 legal problems associated with a lack of enabling legislation caused the CPUC to withdraw its competitive solicitation to select independent program administrators. However, the CPUC continues to promote "outsourcing" type strategies that limit the functions and scope of activities performed by utility administrators. For example, in 2002, with the electricity crisis apparently over, the CPUC took a significant step toward redefining the administration of efficiency programs in California. The CPUC established a set of statewide programs, which were to be managed and implemented largely by the utilities, and established policy goals, budgets, and a competitive solicitation process for "local" programs, which were to be administered and implemented primarily by other entities. Historically, the vast majority of funds have been allocated to the statewide programs and thus, to a large extent, under utility control. However, in 2002 in an effort to increase the flexibility of the programs and better serve hard-to-reach customer segments, the CPUC opted to substantially shift funding toward local programs operated by non-utility entities, allocating approximately $125 million over two years for this purpose. In a break with past practice, the CPUC moved beyond oversight to more directly conduct some program administration functions—the solicitation and selection of the local program proposals (CPUC, 2002a).

The move in California toward "standardized" statewide programs, even though administered by the four utilities, was an attempt to realize some economies of scale. Unlike other states, the California utilities are of sufficient size (e.g., Pacific Gas and Electric's annual retail sales of electricity are almost half the size of all retail sales in the entire Pacific Northwest) that they have the ability to manage statewide market transformation programs targeted at certain markets, such as new construction and residential appliances, although there is some loss in efficiency because of four administrators.

Over time the CPUC has increasingly become disenchanted with various incentive mechanisms to motivate utility performance. Because the CPUC believed that incentive payments were too high, it has steadily lowered the fraction of program budgets available for incentives since the mid-1990s. Between 1998-2000, the CPUC adopted a comprehensive set of 50-75 program and market indicator milestones whose accomplishment was linked to performance incentives and incentives were capped at 10-12% of program expenditures. In 2001, the CPUC revised its approach to performance incentives and adopted fewer milestones, which are linked to energy and peak demand savings and net benefits. In 2002, the CPUC changed its approach again and removed the "carrot" of performance incentives, in favor of the "stick" which involved withholding a portion of program cost recovery pending satisfactory achievement of program goals such as energy and demand savings and program participation (see Table 2). Thus, the CPUC's latest approach relies more on "benchmark competition" and the threat of "local" energy-efficiency programs administered by non-utility parties, rather than providing financial incentives based on performance to motivate utility energy-efficiency program administrators.

California policymakers and energy-efficiency program administrators have also adjusted the mix of programs, their design, and budget allocations as market conditions and relative emphasis among policy goals changed. For example, during the electricity crisis, the CPUC responded by shifting the focus of the 2001 energy-efficiency programs toward short-term energy savings and peak demand reductions. As a result of this move, the public-benefits-funded programs were successful in achieving peak demand reductions of 320 MW in 2001, compared to approximately 190 MW during each of the two prior years (Global Energy Partners, 2003; CPUC, 2001).

The California experience illustrates the difficulty of resolving public policy goals in the absence of a broadly shared consensus. During the 1998-2000 period, the CPUC directed its advisory board (the CBEE) to focus on creating a competitive process to facilitate "independent" administration and re-designing energy-efficiency programs in pursuit of market transformation objectives. This focus was derived in part from the CPUC's broader objectives of stimulating competitive retail energy markets with limited, defined roles for utilities. However, the CPUC was unable to confer sufficient legitimacy to its Advisory Board, while the State was unwilling to provide sufficient staff resources to the CPUC to oversee the "transition" to a contractual relationship with independent program administrators.

In 2000 California's state legislature made a long-term commitment to public benefits funded electric energy-efficiency programs by extending the law that provides funding through 2012. But, while the utilities remain the primary energy-efficiency program administrators, the CPUC continues to temporize on questions of administrative responsibility. Since 1998 the CPUC has granted only short-term extensions of the utilities' authority to administer programs. This continuing uncertainty about the utilities' role in program administration and the turmoil associated with this uncertainty, as illustrated in the ill-fated attempts to select an independent administrator and the controversies surrounding performance incentives and outsourcing, have not supported development of effective long-term programs, much less the creation of a self-sustaining energy–efficiency services infrastructure.

4.3 New York

The primary administrator for energy-efficiency programs in New York is the New York State Energy Research and Development Authority (NYSERDA). Programs are funded through a system benefits charge, which was established through a set of regulatory orders issued in 1996, initially for a three-year period. In 2000, annual funding for the programs was increased substantially, from $58 million to $139 million. NYSERDA's administration of the programs is based on an inter-agency Memorandum of Understanding (MOU) with the New York Public Service Commission (NYPSC), which receives guidance from an independent advisory group in its review of NYSERDA's

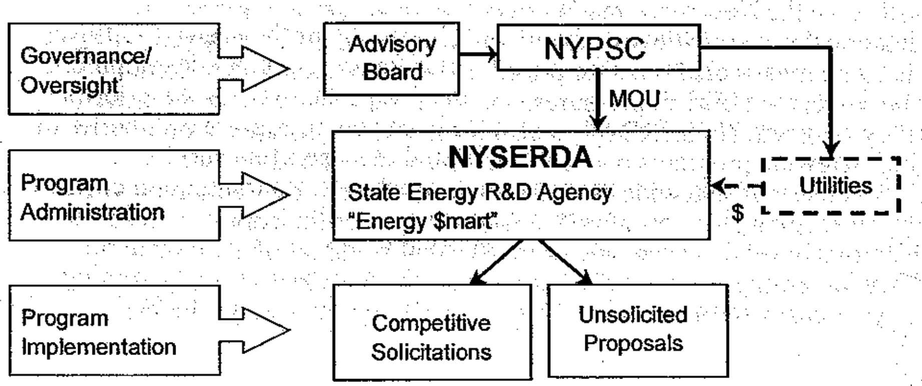

Fig. 2. New York Administrative and Governance Model

program management and implementation (see Fig. 2).

The decision to designate NYSERDA as the administrator of the state's energy-efficiency programs was based on a certain set of policy objectives as well as the previous experiences with utility-administered energy-efficiency programs in New York. In New York, the utilities divested their generation and focused on providing distribution service. Furthermore, the performance of the seven investor-owned utilities' previous energy-efficiency programs had been uneven and the administrative cost of the programs and the incentives required to motivate utility performance were judged to be high in some cases. Moreover, several utilities indicated a lack of interest in continuing to administer energy-efficiency programs. As a result, regulators concluded that, given limited funds and an uncertain duration of public benefit funds, it would be better off working with NYSERDA.

NYSERDA is a public benefit corporation established by the Legislature of the State of New York in 1975 with the mission of conducting an energy R&D program. While the Governor of New York appoints a majority of its Board of Directors and can veto actions of the Board, NYSERDA has developed more flexible competitive procurement processes and contracts, which are less cumbersome and restrictive than those utilized by many state energy agencies. The NYPSC capped NYSERDA's administration expenses at 5% and initially adopted policies with a strong focus on transforming energy-efficiency services markets and stimulating retail markets in which companies would offer energy efficiency as part of a full array of commodity and value-added services. NYSERDA has pursued its market transformation activities by developing statewide energy-efficiency programs that target various market sectors (e.g., Energy Star appliances) and market actors (e.g., motor vendors and contractors), and by coordinating with other energy-efficiency program administrators on regional initiatives. NYSERDA has also devoted significant portions of its budget (27% of the total energy-efficiency budget for 2001-2006) to programs targeted at stimulating an Energy Services Company (ESCO) industry (NYSERDA, 2002). As a result, New York has ~80 active ESCOs and contractors working in its Commercial and Industrial Performance Program and institutional/schools markets. NYSERDA has tended to outsource a large amount of implementation functions, while retaining responsibility for program management and design. While outsourcing has held NYSERDA's costs below the cap set by the NYPSC, it may have shifted administrative costs to contractors and may have somewhat limited NYSERDA's ability to build up its own expertise.

Thus, NYSERDA has had some success in creating an energy-efficiency services infrastructure that will serve the New York market over the longer term, which is consistent with the historic "economic development" philosophy of the agency (Gilligan, 2003). However, it is by no means clear that the priorities for an economic development agency, which may be subject to political pressures, are always the same as the priorities for an energy efficiency program. NYSERDA has also been able to capture economies of scale by administering statewide programs and has offered end users and service providers in New York consistent statewide programs, which reduces transaction costs of participating. Finally, by keeping basic program management under the control of state government, administrators have also been able to respond to the threat of short-term generation shortfalls by increasing the emphasis on peak demand savings and targeting programs to constrained areas with transmission and supply bottlenecks (e.g., the New York City area).

4.4 Vermont

Vermont chose to hold off restructuring its retail electricity industry, but nevertheless decided to transition its energy-efficiency programs to a new administrator. The approach taken by Vermont's legislature was to consolidate the administration of all energy-efficiency programs under a single "Energy Efficiency Utility" whose sole purpose is to deliver energy-efficiency programs. The Energy Efficiency Utility is responsible for the majority of administrative functions, including program management, design, and implementation. Funding is generated through a system benefits charge on customers' electric bills. The specific entity that administers the programs, called Efficiency Vermont, was selected through a competitive solicitation and is a non-profit corporation.[9] Efficiency Vermont operates under a three-year contract with the Vermont Public Service Board (PSB), which was renewed for a second three-year term. A Fiscal Agent collects funds from the utilities and pays Efficiency Vermont, subject to approval of its invoices by a Contract Administrator. The Contract Administrator is also responsible for contract management, overseeing minor changes to scope of work and verifying performance. The Vermont Department of Public Service, which is a state energy office, provides policy

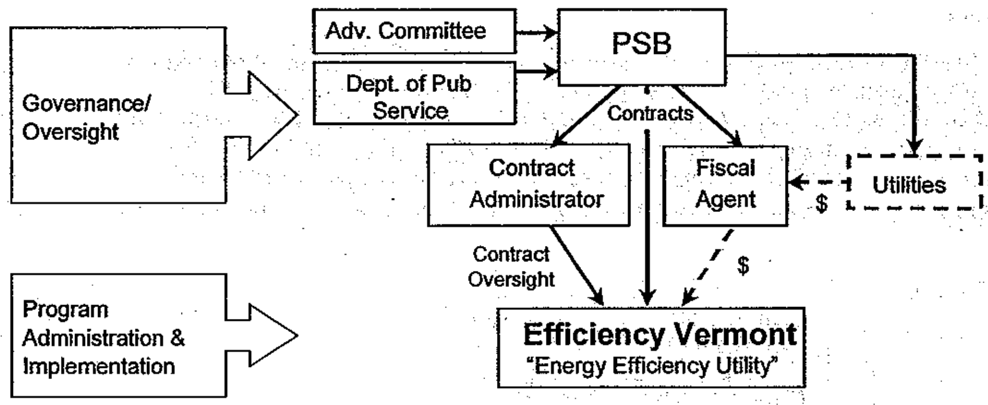

Fig. 3. Vermont Administrative and Governance Model. Adapted from Hamilton et al (2002).

and program evaluation input to the PSB (see Fig. 3). The Advisory Committee, which is composed of stakeholder representatives appointed by the PSB, acts as a channel of communication between Efficiency Vermont and important stakeholders.

Although the entity serving as Efficiency Vermont is a non-profit corporation, at the end of the initial contract period it could earn an incentive payment of up to 2.9% of the value of its contract with the PSB. This payment is based on several measures of performance including energy savings, total resource benefit, and several market-specific indicators, which are tightly linked to the broader public policy goals articulated by the PSB. The PSB believes that the performance incentives have been quite effective in focusing Efficiency Vermont and continued that approach in the second contract.

This unique administrative structure was adopted as a result of a number of factors particular to the state. Vermont is a small, rural state with approximately 600,000 people. Prior to the creation of Efficiency Vermont, energy-efficiency program activity was limited and the existing programs were administered separately by 22 small utilities. Performance among these utilities was quite uneven, and the regulatory oversight entailed in reviewing programs for many small utilities proved to be quite costly and burdensome for the small staff of the PSB, the Department of Public Service, and the utilities. The Vermont PSB sought to improve the quality and consistency of programs by mandating a single set of programs to be offered statewide, while also taking advantage of the increased scale of operation to create a more cost-effective delivery mechanism. These factors made the option of using a single organization to administer all energy-efficiency programs in the state an attractive approach. Thus, Vermont has made a conscious decision to build a long-term energy-efficiency services infrastructure through Efficiency

[9] Some for-profit companies were among the competitiors.

Vermont, which provides a "one-stop" shopping model of energy-efficiency services. This model makes sense in small states or geographic regions or rural states where large, national private ESCOs or retailers are unlikely to enter the market.

In Vermont, all four of our criteria appear to have been factors in the decision to move to a statewide Energy Efficiency Utility: establishing an organization whose mission was well-aligned and compatible with the state's energy-efficiency policy objectives, capturing economies of scale to reduce administrative costs by transitioning from 22 utilities to statewide administrator, use of performance incentive mechanisms to motivate the administrator, and an approach to building an efficiency services infrastructure that was tailored to the conditions in a small rural state.

4.5 Connecticut

The basic administrative structure in Connecticut is similar to that originally adopted in California during the 1998-2000 period. The energy-efficiency programs are administered by the state's two large investor-owned utilities, subject to the regulatory oversight of the Connecticut Department of Public Utility Control (DPUC). An independent advisory board, the Energy Conservation Management Board (ECMB), which holds regularly scheduled public meetings, was created to provide a forum for

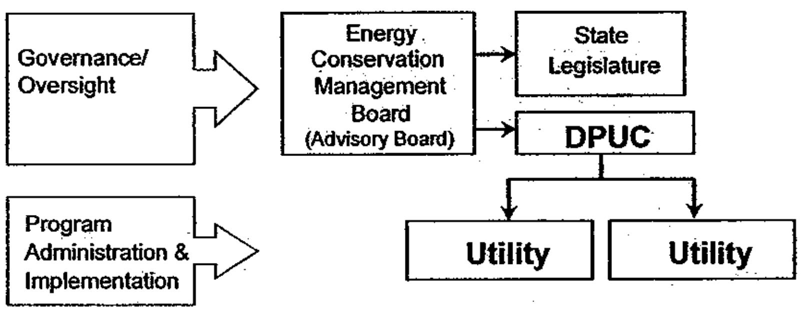

Fig. 4. Connecticut Administrative and Governance Model

public input and to make recommendations to the DPUC and Legislature on energy-efficiency policies and program design, program mix, and budgets (see Fig. 4). Funding for the programs is provided through a system benefits charge, which was authorized as part of the state's restructuring legislation.

The basic administrative and governance structure in Connecticut was formulated during the restructuring process in an attempt to address a number of issues identified with the existing approach. The two investor-owned utilities had previously been responsible for providing energy-efficiency programs, but the programs were not uniform, and because of the utilities' financial disincentives to pursuing end-use energy efficiency, the DPUC believed that significant staff resources and financial incentives were required to motivate utility management. The DPUC sought to create a set of statewide programs in order to reduce customer transaction and administrative costs, and to establish greater market presence and continuity with vendors and manufacturers. The ECMB was created to facilitate these efforts. This administrative structure has thus far proved successful, in terms of generating a set of consistent statewide programs and has also provided sufficient flexibility to respond to short-term conditions, by targeting additional funds and efforts towards southwestern Connecticut, where acute transmission constraints were identified as a significant reliability threat.

Connecticut has elected to maintain a regulatory oversight rather than a contract model in energy-efficiency program administration. The ECMB has been able to function effectively as an Advisory Board and provide guidance and recommendations on how to achieve DPUC policy goals. The governance/oversight structure has been less contentious than in California (i.e., the CBEE role as advisory board to CPUC) for two primary reasons: 1) the ECMB was authorized by and reports to the Connecticut Legislature and thus has greater "legitimacy" and 2) Connecticut's policy and programmatic directions to the ECMB were narrower in scope and required fewer institutional changes than the CPUC's guidance to the CBEE during the 1998-2000 period. Policymakers in Connecticut have relied on a two-pronged strategy to address potential disincentives of utility program administration: 1) financial incentives to utility shareholders as a way of aligning the utility's performance as a program administrator with the state's objectives for energy efficiency, and 2) reliance on an independent Advisory Board to provide input on energy-efficiency programs, program design, budgets, and balancing among policy goals.

5. Conclusion

In the US, electricity restructuring has resulted in significant changes in the acquisition of energy-efficiency resources as an outgrowth of an Integrated Resource Planning process, in establishing a role for transforming markets as a new policy objective, and in stimulating new models for administration and governance of these activities. Prior to restructuring, energy-efficiency program budgets and savings goals were developed as part of Integrated Resource Plans, and thus budgets could change fairly significantly when plans were updated depending on the overall supply/demand balance, energy-efficiency program cost-effectiveness, and rate impacts. After restructuring, in those states that adopted system benefits charges, the energy-efficiency planning process has changed somewhat as regulators/administrators are given some pre-specified amount of public benefits funds which is typically known over a multi-year period and legislatively or administratively authorized. The issues faced by regulators/administrators focus on how to allocate those funds among customer market segments, types of programs/activities, and the balance between near-term acquisition of electricity and peak demand savings vs. longer-term activities designed to reduce market barriers and create a sustainable energy-efficiency services markets/industry.

No single administrative structure for energy-efficiency programs has yet emerged in the US that is clearly superior to all of the other alternatives. And, in our view, this is not likely to happen soon for several reasons. First, policy environments differ significantly among the states. Second, the structure and regulation of the electric utility industry differs among the regions of the US. For example, in Vermont, the PSB regulates public and investor-owned utilities, many of which are quite small, while in most other states, PUCs regulate only investor-owned utilities, many of which are large. In addition, vertically integrated utilities continue to operate in many states, including states that allow retail competition. These different arrangements affect the administrative capabilities and perceived and actual financial disincentives of utilities to promote energy efficiency. In addition, senior management at utilities vary significantly in their interest in and commitment to effectively administer and design energy efficiency programs that are part of a regulatory or legislative mandate. Third, market transformation and resource acquisition, which once were seen as alternative strategies, are increasingly coming to be seen as complementary strategies. Going forward, energy-efficiency programs and activities in various markets (e.g., appliances, new construction) are likely to include elements of both strategies. But, the administrative arrangements that are best suited to support market transformation may be different from the arrangements that are best for resource acquisition.

The differences in policy environments are partly due to different experiences with restructuring. By-products of electricity market restructuring, which include increased price volatility in wholesale electricity markets, occasional price shocks and system reliability events, have forced energy-efficiency program administrators to react quickly to these "short-term" crises with programs designed to reduce load, summer peak demand, or targeted at constrained areas. In some cases, they have had to divert attention from their longer-term market transformation goals and re-allocate program budgets and resources to address local emergencies (New York, Connecticut). In places where the crisis has been quite severe (California), there is a more fundamental re-thinking of the role of planning. In California, with the suspension of retail competition, the CPUC has directed the utilities to submit what are essentially Integrated Resource Plans as part of their proposals for procuring long-term resources.

When resource acquisition is the primary objective, utilities—provided that they are large enough—remain candidates for program administrators. Utilities have easy access to customers and are often trusted intermediaries between customers and suppliers of energy-efficiency products and services. The effectiveness of resource acquisition programs is relatively easy to measure, so incentives can be tied to performance. The situation is somewhat different if market transformation is the primary objective. Access to customers is not as important since most programs are not "one-customer-at-a-time." Often the targets are not customers but are suppliers like appliance or equipment manufacturers or intermediaries like lenders and retail product distributors. Program success and attribution of success to the administrator's activities are more difficult to measure. Performance incentives for these activities, if offered, may be based on both subjective measures such as of stakeholders' opinions about the value of the administrator's efforts and objective measures such as changes in market share. However, objective measures such as changes in market share may be difficult or costly to obtain given available market data. If the view that resource acquisition and market transformation are complements gains ascendancy, we may see the emergence of more arrangements like that in the Pacific Northwest where a single-purpose regional agency administers market transformation programs and utilities or non-utility entities (either state agencies or non-profit corporations) administer resource acquisition programs.

The debate over administration of energy-efficiency programs has often centered on the incentives, motivation, and capabilities of utilities vs. other types of entities. Issues related to developing an energy-efficiency services infrastructure have often been framed in terms of activities that can/should be performed by the administrator (that is, the utility) vs. private sector entities. Often, missing in this discussion is a more fundamental discussion on the underlying strategy to create a vibrant, long-term energy-efficiency services infrastructure, particularly one that serves residential and small commercial customers. Over time, it will be necessary to pay more attention to this issue if energy efficiency is to achieve its full promise and potential.

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Table 2
Administrative Structure of Energy-efficiency Programs in Five U.S. States/Regions

	Pacific Northwest [e,f]	**California** [a,g,k]	**New York** [a,c,d]	**Vermont** [a,b]	**Connecticut** [a,b,i,j]
Administrator	Northwest Energy Efficiency Alliance	Pacific Gas & Electric, Southern California Edison, Southern California Gas Company, and San Diego Gas and Electric	New York Energy Research and Development Authority (NYSERDA)	Efficiency Vermont	Connecticut Light and Power, United Illuminating
Organization Type	Regional nonprofit	Investor Owned Utilities	State Authority	Energy Efficiency Utility	Investor Owned Utilities
Governance	Board of Directors	Oversight by California Public Utilities Commission	MOU with New York Public Service Commission; input from advisory board	Contract with Vermont Public Service Board	Oversight by Connecticut Public Utilities Commission with input by ECMB advisory board
Funding Source	Ratepayer funding or public benefits funding from BPA and utilities in each state	Public Benefits Fund through surcharge of 1.3 mills/kWh	Public Benefits Fund through surcharge of 0.83 mills/kWh	Public Benefits Fund through surcharge	Public Benefits Fund through surcharge of 3.0 mills/kWh
Duration	Indefinite	Through 2012	Through June 2006	No sunset in legislation; three-year contract with Administrator	Indefinite
Annual Budget (approx)	$20 million (NEEA only)	$275 million	$74 million (EE only)	$13 million	$86 million
Performance Mechanism	None	A portion of cost recovery witheld pending satisfaction of program goals, including energy and peak demand savings as well as various program-specific participation goals	None	Electricity and Peak Demand Savings, Total Resource Benefit, and several market-specific indicators	Primarily based on electricity savings, with several additional program-specific participation goals
Performance Incentive	None	Up to 15% of cost recovery at risk	None	2.9% of contract value; maximum of $1.28 million cap over contract period	Up to 8% of expenditures

a. (ACEEE, 2003)
b. (Hamilton et al., 2002).
c. (York et al., 2002)
d. (NYSERDA, 2002)
e. (NEEA, 2002a)
f. (NEEA, 2002b)
g. (CPUC, 2001)
h. (UI, 2002)
i. (ECMB, 2002)
j. (DPUC, 2001)
k. (CPUC, 2002b)

The Regulatory Assistance Project

REVENUE DECOUPLING

STANDARDS AND CRITERIA

A Report to the Minnesota Public Utilities Commission

30 June 2008

Final

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I. Introduction

In 2007, the Minnesota legislature enacted a new statute, Section 216B.2412, in which it defined an alternative approach to utility regulation, *decoupling*, and directed the Public Utilities Commission (PUC) to "establish criteria and standards" by which decoupling could be adopted for the state's rate-regulated utilities. In addition, the legislation authorized the PUC to allow one or more utilities "to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation," subject to the criteria and standards that the PUC will have established. The full text of Section 216B.2412 can be found in Appendix A.

To fulfill its obligation to develop criteria and standards for decoupling, the PUC sought the advice of the Regulatory Assistance Project (RAP). RAP is a non-profit organization dedicated, as its name connotes, to providing policy and technical assistance to regulators and other government officials on the full range of matters relating to the economic and environmental sustainability of the regulated natural gas and electric sectors. It was formed in 1992.[1]

The groundwork for this report was laid through a series of meetings April and May 2008 with commissioners and staff of the PUC, officials at the Office of the Attorney General, and staff at the Office of Energy Security, through written comments from stakeholders, and through a two-day workshop attended by representatives of the state agencies, affected utilities, and other interested parties. This report is the output of that collaboration.

A. What is Decoupling?

Section 216B.2412 states succinctly that decoupling is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." Specifically, decoupling takes aim at one of the critical barriers to increased investment in cost-effective energy efficiency and other clean energy resources located "behind the customer's meter"—namely, the potentially deleterious impacts that such investment can have on utility

[1] RAP's principals are all former, highly experienced utility regulators. They have written and spoken extensively on numerous issues relating to energy policy and regulation, including efficiency, renewables, distributed resources, portfolio management, industry restructuring (e.g. market power, stranded costs, system benefits charges, customer choice, and consumer protection), reliability and risk management, rate design, electrical energy security, and environmental protection. Decoupling has been a particular focus of RAP's work over the years. RAP principals were involved in the development of decoupling programs in New England and the Northwest in the 1990s and, more recently, have provided technical assistance on it to a number of states (among them Maine, Massachusetts, Maryland, New Hampshire, the District of Columbia, and Oklahoma). This work has been underpinned by more in-depth analytical work on the mechanics of decoupling and utility incentives to encourage increased investment in energy efficiency. See, for instance, *Profits and Progress through Distributed Resources* (2000), *Performance-Based Regulation for Distribution Utilities* (2000), the Revenue Stability Model Rate Rider (2006), and "Utility Business Models: Clean Energy Incentives and Disincentives" (2008), all available at our website, www.raponline.org.

finances under traditional cost-of-service regulation. Traditional regulation, which is an exercise in price-setting, creates an environment in which revenue levels are a function of sales—kilowatts, kilowatt-hours, or therms. Consequently, a utility's profitability depends on maintaining or, more often, increasing sales, even though such sales may be, from a broader societal perspective, economically inefficient or environmentally harmful.

All regulation is, in one way or another, incentive regulation. A question all policymakers should ask is: how does a regulated company make money? What are the incentives it faces and do they cause it to act in a manner that is most consistent with, and most able to advance, the state's public policy objectives? And, if not, how should regulatory methods be reformed to correct such deficiencies?

Traditional regulation does not set a utility's revenues, only its prices. Once prices are set, the utility's financial performance depends on two factors: its levels of electricity sales and its ability to manage its costs. Because, under most circumstances, a utility's marginal revenue (i.e., price) significantly exceeds its short-run marginal costs, the impacts on profits from changes in sales can be profound. Moreover, the change in profits is disproportionately greater than the change in revenues. A utility therefore typically has a very strong incentive to increase sales and, conversely, an equally strong incentive to protect against decreases in sales.[2] This is referred to as the "throughput incentive," and it inhibits a company from supporting investment in and use of least-cost energy resources, when they are most efficient, and it encourages the company to promote incremental sales, even when they are wasteful.

The solution to the throughput problem is to adopt a means of collecting a utility's revenue needs that is not related to its actual volumes of sales. Decoupling, whereby the mathematical link between sales volumes and revenues is broken, eliminates the throughput incentive and focuses a utility's attention on its customers' energy service requirements and the economic efficiency of its own operations.[3] It renders revenue levels immune to changes in sales. Of equal importance, decoupling allows for the retention of volumetric, unit-based pricing structures that reflect the long-term economic costs of serving demand and preserves the linkage between consumers' energy costs and their levels of consumption.

Decoupling, in its current manifestations, is being applied only to the network, delivery components of the gas and electric industries. The costs of the gas and electric commodity portions of service are typically recovered through purchased gas and fuel adjustment clauses or, if provided competitively, through payments to suppliers. In effect, where such adjustment clauses are used, the commodity costs are already decoupled and changes in these costs due to changes in sales or in the underlying price of the commodity do not have an effect on the utility's profits. In this report, only the monopoly pipes and wires components of the networks need be addressed through a decoupling mechanism.

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[2] See Appendix B for the mathematical bases for these conclusions.

[3] This point deserves emphasis. Decoupling breaks the link between unit sales and revenues, not *profits*. Decoupling does not assure the utility a fixed level of earnings but rather a pre-determined level of revenues: the actual level of profits will still depend on the company's ability to manage its costs.

A number of states have taken, or are now taking, steps to reform their methods of regulation to resolve the conflict between the "throughput" incentive and important public policy objectives. Decoupling, in one form or another, has been adopted for electric and gas utilities in California, Oregon, Washington, Maryland, Idaho, New York, New Jersey, Utah, Indiana, Ohio, North Carolina, and Vermont, and it is currently under review in Connecticut, Maine, Massachusetts, and the District of Columbia. See Appendix D for descriptions of decoupling regimes in the various jurisdictions.

B. Terminology

In this report, we describe the several approaches to decoupling taken by a number of states, and we use a specialized vocabulary to differentiate among them. These terms of art should, for clarity's sake, be defined, and the differences among them explained, at the start.

1. Full Decoupling

Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation—e.g., increased investment in energy efficiency, unexpected weather, changes in economic activity—does not matter. Any and all deviations will result in an adjustment ("true-up") of collected utility revenues with allowed revenues.

Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement—i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service—is determined. The utility then knows exactly how much money it will be allowed to collect, no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget.[4]

The most common form of full decoupling is revenue-per-Customer (RPC) decoupling, in which the allowed revenue requirement between rate cases is changed only as the number of customers served changes.

Full decoupling renders a utility indifferent to changes in sales, regardless of cause. It eliminates the "throughput" incentive. The utility's revenues are no longer a function of sales, and its profits cannot be harmed or enhanced by changes in sales. Only changes in expenses will then affect profits.

Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in

[4] This is the simplest form of full decoupling. As described later in this report, most decoupling mechanisms actually allow for revenues to vary as factors other than sales vary. The reasoning is that, though in the long run utility costs are a function of demand for the service they provide, in the short run (i.e., the rate case horizon), costs vary more closely with other causes, primarily changes in the numbers of customers.

energy efficiency or other customer-sited resources, but its natural antagonism to such resources is removed.

2. Partial Decoupling

Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 90% of the revenue shortfall is recovered).

3. Limited Decoupling

Under limited decoupling, only specified causes of variations in sales result in adjustments. For example:

(A) Only variations due to weather are subject to the true-up (i.e., actual year revenues (sales) are adjusted for their deviation from weather-normalized revenues). This is simply a weather normalization adjustment clause. Other impacts on sales would be allowed to affect revenue collections. Successful implementation of energy efficiency programs would, in this context, result in reductions in sales and revenues from which the utility would not be insulated—that is, all else being equal, energy efficiency would adversely affect the company's bottom line.

(B) Variations due to some or all other factors (e.g., economy, end-use efficiency) except weather are included in the true-up. In this instance, the utility and, necessarily, the customers still bear the revenue risks associated with changes in weather. And, lastly,

(C) Some combination of the two.

Limited decoupling requires the application of more complex mathematical calculations than either full or partial decoupling, and these calculations depend in part on data whose reliability are sometimes vigorously debated. But, more important than this is the fundamental question that the choice of approaches to decoupling asks: how are risks borne by utilities and consumers under decoupling, as opposed to traditional regulation? What are the expected benefits of decoupling, and what, if anything, will society be giving up when it replaces traditional price-based regulation with revenue-based regulation? These and other questions are taken up in the following chapter.

C. Structure of the Report

Chapter II analyzes the key issues—among them, impacts on customers, effects on utility investment, how risks are borne by the utility and the consumer, impacts on capital costs—that decoupling elicits. In that chapter, we address concerns and questions raised in meetings and correspondence with government officials and other interested parties. Chapter III lays out our recommendations for both the elements that a decoupling proposal should include (i.e., minimum standards) and the criteria by which it should be evaluated. Chapter IV gives an example of a decoupling program that meets those standards and criteria. The Appendices provide more detailed information about Minnesota's decoupling legislation, the mechanics of decoupling, and approaches to it in other states.

II. Issues

A. Investment in End-Use Efficiency and Other Customer-Sited Resources

Decoupling, which allows a utility to collect revenues according to a mathematical rule (i.e., revenue per customer, historic or future test year revenue requirement, etc.) that is not driven by unit sales, gives the firm a strong incentive to improve its operational efficiency. Indeed, it is only through such productivity increases that the company will be able to earn increased profits, as any margins associated with incremental sales will be returned to consumers (as, conversely, will any lost margins resulting from decreased sales be absorbed by consumers). In this light, an argument can be made that decoupling is appropriate on broad economic efficiency grounds, since it removes the company's inhibition from supporting investment in and use of least-cost energy resources, when they are most efficient, and likewise relieves it of its incentive to promote incremental sales, even when they are wasteful.

The removal of the throughput problem is critical if utilities are not to view investment in energy efficiency as a financial threat, but by itself it does not give them a positive incentive to support investment in behind-the-meter resources. It merely makes them financially indifferent to resource choices. Consequently, if increased investment in energy efficiency is a goal of state policy, a decision to decouple should be accompanied by specified efficiency performance requirements and possibly positive incentives for good or superior performance. It is important to see decoupling as one in a suite of complementary policies that can put the gas and electric sectors on a more economically sustainable long-term path.

B. Impacts on Customers

Several participants in the workshops and meetings expressed concerns about the potential impacts of decoupling on consumers. What are its costs and benefits, and can they be easily quantified so as to inform the decision-making and design process? Does regulatory lag—the interval between rate cases—benefit or harm ratepayers, and how does decoupling affect it? Should a change in regulatory methods be adopted only if it can be shown to do no harm to consumers, and how should "no harm" be defined?

The benefits and costs of decoupling, relative to traditional regulation, might be categorized as follows: (1) those associated with regulation and administration, (2) those having to do with short-term impacts on the revenue requirement, and (3) those having to do with the long-term societal costs of meeting demand for service.

In the first instance, a decoupling regime, once in place, should impose little incremental regulatory costs for either the utility or the regulatory agencies themselves. The overwhelming cost in ratemaking is the rate case itself, and decoupling will not change the nature of "soup to nuts" rate cases. To the degree that a decoupling program alters the timing of rate cases, their aggregate cost over a multi-year period will either increase or decrease when compared to what was expected to happen under traditional regulation. It is reasonable to expect that, with risk and revenue volatility reduced, a well-designed decoupling program (one that possibly allows for adjustments according to changes in short-term drivers such as numbers of customers, inflation, and productivity) could reduce the frequency of general rate cases. The costs of administrating the decoupling program itself—for example, the periodic adjustments to rates—should be negligible, akin to those associated with other on-the-bill rate adjustment mechanisms such as purchased gas adjustment clauses.

In the second case, the question really comes down to regulatory lag. Under traditional regulation, once prices are set, the company's profitability is a function of two things: its sales and its ability to manage its costs. If its earnings are (at least) satisfactory, it will not seek an increase in rates. To the extent that its earnings exceed its allowed returns, and the regulatory commission does not initiate a rate reduction proceeding, shareholders benefit from regulatory lag. The longer a rate case is avoided, the better off they are, and consumers will pay more for service than is necessary. Conversely, when earnings begin or threaten to decline, the company will seek rate relief. Regulatory lag in this case harms shareholders.[5] Rates are lower than they would otherwise be, and this is deemed to be a benefit to ratepayers. Therefore (and setting aside for the moment issues of how capital markets assess the risks, including regulatory lag, that utilities bear under traditional regulation), whether regulatory lag is of value to consumers or shareholders depends entirely on the underlying circumstances.

Decoupling reduces or even eliminates regulatory lag with respect to changes in sales volumes. If we conclude that, over the long term, the gains and losses of regulatory lag under traditional regulation are evenly distributed, then we might also find that, on this point at least, decoupling offers no incremental benefit to, nor imposes no incremental cost on, consumers or shareholders. In the long run, consumers will pay for the system that their demand creates and shareholders will be compensated for their investments. Under traditional regulation, there will be some periods in which they will pay a little more than they should, and in other periods a little less. Under decoupling, there will be neither over-collections nor under-collections of allowed revenues.[6] Even so, if there are underlying trends in consumption, regulatory lag under traditional regulation will reflect those trends in the utility's revenues and, therefore, its profits – utilities with increasing sales per customer (typical of electric utilities) will tend to see higher profits with longer regulatory lag, while those with decreasing sales (typical of gas utilities) will tend to see greater profit erosion. These trends can have impacts on the utility's perceived risk profile and, therefore, its cost of capital.[7]

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[5] One example of this is the company whose sales volumes (per customer or in the aggregate) are falling. As a general matter, this describes Minnesota's natural gas utilities.

[6] Strictly speaking, this will depend on the frequency of the decoupling adjustments. Small gains and losses can flow from, say, quarterly or yearly adjustments. Monthly (i.e. "current") adjustments based on actual sales levels will eliminate regulatory lag altogether.

[7] See the subsection following for a fuller discussion of the impacts of decoupling on risk.

The third category of benefits and costs are those that flow from the longer-term changes in behavior that decoupling causes. One is management's greater focus on operational efficiency that a revenue cap creates, particularly one that has explicit adjustments for productivity gains over time. Another is the overall savings that consumers enjoy from an increased emphasis on long-term, least-cost strategies for meeting demand. As mentioned earlier, this emphasis will derive from the express public policy directives that accompany—and are made more realizable—by decoupling. Chief among those actions should be, as the legislation calls for, increased investment in end-use energy efficiency, but there are others too that utilities and regulators may be more apt to test and utilize, if the problem of revenue erosion has been resolved. One such action could be the reduction of fixed, recurring customer charges and the corresponding increase in unit charges to more accurately reflect the long-run economic and environmental costs of energy production and delivery.

Lastly, Section 216B.2412, Subd. 2, requires that "The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 *without adversely affecting utility ratepayers*." (Emphasis added.) There was some debate in the workshops and meetings about precisely what this means. This is, ultimately, a question of law that the Commission must decide. We suggest here that there are at least several kinds of impacts, both adverse and otherwise, that ought to be considered when evaluating the differences between decoupling and traditional regulation: the intertemporal distribution of costs and benefits, effects on bills v. effects on rates, the direct and indirect effects on market prices, risk and its effect on the cost of capital, and environmental impacts, to name a few. In certain cases they can be readily quantified and the trade-offs examined, in others not. But, either way, Minnesota law requires that they be factored into an assessment of whether this form of regulation, or any other, is most likely to promote the general good of the state.

C. Weather, the Economy, and Other Risks

While traditional regulation aims to determine a utility's costs and then provide appropriate prices to recover those costs, there are a number of factors which prevent this from happening. Foremost among these are the effects of weather and economic cycles on utility sales and customer bills. These effects are directly related to how prices are set. Full or Limited Decoupling, and some forms of Partial Decoupling, will have a direct impact on the magnitude of these risks. For the most part, Full Decoupling will eliminate these risks completely. Limited Decoupling partially eliminates these risks. Partial Decoupling may or may not affect these risks, depending upon whether the presence of a particular risk is desired.

1. Risks Present in Traditional Regulation

The ultimate result of a traditional rate case is the determination of the prices charged consumers. In simple terms, a utility's prices are set at a level sufficient to collect the costs incurred to provide service (including a "fair" rate of return-- the utility's profits). Because most of the revenues are normally collected through volumetric prices based on the amount of energy consumed or the amount of power demanded, the assumed units of consumption are critical to getting the price "right."[8] The basic pricing formula under traditional regulation is:

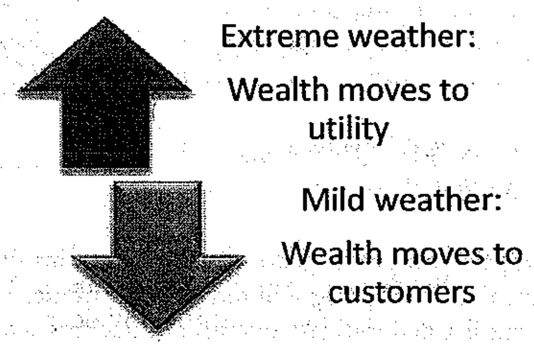
Price = Revenue Requirement ÷ Units of Consumption

This formula is applied using Units of Consumption associated with normal weather conditions. As long as the units of consumptions remain unchanged, the prices set in a rate case will generate revenues equal to the utility's Revenue Requirement. Also, if extreme weather occurs as often as mild weather, over time the utility's revenues will, on average, approximate the revenue requirement. In theory, this protects the company from under-recovery and customers from over-payment of the utility's cost of service because there should be an equal chance of having weather which is more extreme or milder than normal.

In reality, this is hard to accomplish because in any given year, the actual weather is unlikely to be normal. Thus, even if the traditional methodology results in prices which are "right" and the weather normalization method used was accurate, the *actual* revenues collected by the utility and paid by the customers will be a function of the *actual* units of consumption, which are driven, in large part, by actual weather conditions, according to the following formula:

Actual Revenues = Price * Actual Units of Consumption

Effect of Weather under Traditional Regulation On Utility Revenues and Customer Bills



With this formula, extreme weather increases sales above those assumed when prices were set, in which case utility revenues and customer bills will rise. Conversely, mild weather decreases utility revenues and customer bills. To the extent that the utility's costs to provide service due to the increase or decrease in sales do not change enough to fully offset the revenue change, then, in economic terms, this is considered to be a wealth transfer between the utility and its customers. This wealth transfer is unrelated to what the utility *needs* to recover and what customers *ought* to pay. This transfer is not a function of any explicit policy objective. Rather, it is simply an unintended consequence of traditional regulation. There is a volatility risk premium embedded in the utility's cost of capital that reflects the increased variability in earnings associated with weather risk. This premium may be reflected in the equity capitalization ratio, the rate of return, or both.

[8] By "right," we mean consistent with the cost of service methodology.

2. Economic Risk

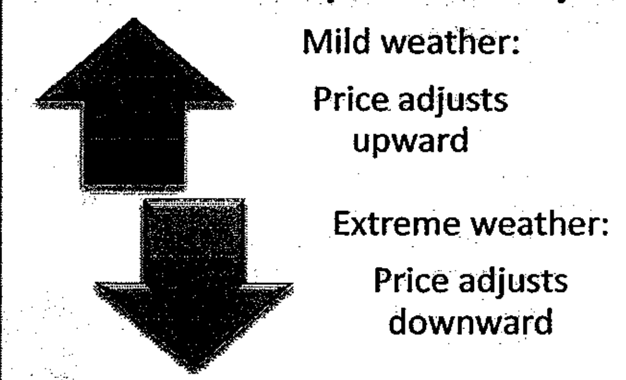
Other changes in circumstances, such as a significant change in economic conditions, can also affect a utility's revenues. Any upswing or downswing in either overall consumption levels or in the number of customers can potentially have a significant impact on revenues. Unlike weather risk, economic risk does not directly result in a wealth transfer between the utility and its customers, at least in so far as the increased or decreased consumption is associated with increased or decreased value received. Instead, the utility largely bears the benefit or burden of changed economic conditions between rate cases, while existing customers see no change in their bills. At the time of the next rate case, however, the utility's revenues are reset to approximate their cost of service and customers then see the effect of changed economic conditions going forward. As in the case of weather risk, there is an implicit volatility risk premium in the utility's cost of capital that reflects the increased variability in earnings associated with changed economic conditions.

3. The Impact of Decoupling on Weather and Other Risks

Full decoupling causes a utility's revenues to be immune to both weather and economic risk. Once the revenue requirement is determined (in the rate case or via the RPC adjustment), decoupling adjusts prices to maintain the allowed revenue requirement. Any change in consumption associated with weather or other causes will result in an inverse change in prices, according to the following formula:

Price = Allowed Revenue ÷ Actual Units of Consumption

Effect of Weather With Decoupling
On The Non-Commodity Portion of Utility Bill



As consumption rises, prices are reduced. As consumption falls, prices are increased. This means that decoupling will mitigate the higher overall bill increases associated with extreme weather and mitigate overall bill decreases associated with mild weather. With Full Decoupling, all changes in units of consumption, regardless of cause, are translated into price changes to maintain the allowed revenue level. Thus, no matter the amount of consumption, the utility and the consumers as a whole will receive and pay the Allowed Revenue. Neither the company nor its customers are exposed to weather or economic risks in this case.

Under Limited Decoupling, only a portion of the indicated price adjustment is collected or refunded. To the extent the adjustment is limited, both weather and economic risks are placed upon the utility and its customers.

Under partial decoupling, the weather or economic risks may be selectively imposed on the utility and its customers. Some states have preserved weather risk in a decoupled environment by weather normalizing Actual Unit Sales before computing the new price under partial decoupling. This has the effect of fully exposing the utility and its customers to weather risk.

Conversely, one might limit the changes in unit sales to those directly attributable to efficiency programs. Lost margin mechanisms, discussed below under Alternatives to Decoupling, are one example of this type of partial decoupling. This has the effect of preserving all of the risks, including weather and economic risks, which would be present under traditional regulation.

Any risks placed on the utility and its customers will likely increase the overall revenue requirement of the utility because of its impact on the utility's financial risk profile. This is explored further in the following section, *Volatility Risks and Impacts on the Cost of Capital.*

D. Volatility Risks and Impacts on the Cost of Capital

Utility earnings can be volatile because of the way weather and other factors influence sales volumes and revenues in the short run, without corresponding short-run impacts on costs. As a result of this volatility, utilities typically retain a relatively high level of equity in their capital structure, so that a combination of adverse circumstances (adverse weather, economic cycle, cost pressures, and customer attrition) does not render them unable to service their debt. In addition, utilities also try to pay their dividends with current income or from retained earnings. In fact, most bond covenants prohibit paying dividends if retained earnings decline below a certain point. A utility that is forced to suspend its dividend is viewed as a higher risk venture.

Decoupling can significantly reduce earnings volatility due to weather and other factors and can eliminate earnings attrition when sales decline, regardless of the cause (e.g., appliance standards, energy codes, customer or utility-financed conservation, self-curtailment due to price elasticity, etc.). This in turn, lowers the financial risk for the utility, which in turn is reflected in the company's cost of capital.

The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity; but this generally requires several years to play out and the consequent benefits for customers are therefore slow to materialize. Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place.

1. Rating Agencies Recognize Decoupling

The bond rating agencies have come to recognize that decoupling mechanisms, weather adjustment mechanisms, fuel and purchased gas adjustment mechanisms, and other outside-the-rate-case adjustment mechanisms all reduce net earnings volatility and risk, and therefore contribute to a lower cost of capital for the utility. It is important when selecting "comparable" utilities for cost of capital studies to use only utilities with similar risk-mitigation tools in place, so that an apples-to-apples comparison is possible.

Standard and Poor's has explicitly recognized risk mitigation measures by rating the "business risk profile" of utility sector companies on a scale of 1 to 10. The distribution utilities without supply responsibility and with risk mitigation measures are mostly rated 1 to 3, while the independent power producers without stable customer bases or any risk mitigation measures are 7 to 10. The vertically-integrated utilities with some risk mitigation measures are in-between.[9]

The risk mitigation of decoupling can be reflected in either of two ways. First, it can be directly applied to reduce the equity capitalization ratio of the utility in a rate case. This has the effect of reducing the overall cost of capital and revenue requirement, without changing either the cost of debt or the allowed return on equity. The table below summarizes how a change in the equity capitalization ratio reduces the revenue requirement.

Quantification of Savings from Capital Structure Shift
$1 Billion Rate Base

Element	*Allowed Return*	*Ratio w/o Decoupling*	*Ratio With Decoupling*
Equity	11%	45%	42%
Debt	8%	55%	58%
Overall Return with Taxes		10.48%	10.13%
Revenue Requirement		$104.8 million	$101.3 million
Difference			($3.5 million)

The overall impact is on the order of a 3% reduction in the equity capitalization rate, which in turn can produce about a 3% decrease in revenue required for the return on rate base, or about a 1% decrease in the total cost of service to consumers (including power supply or natural gas supply). This is not a large impact – but it is on the same order of magnitude as many utility energy conservation budgets, meaning that cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

It is important to recognize that this type of change involves neither a reduction in the return on equity, nor a reduction in the allowed cost of debt. It simply reflects a realignment of the amount of each type of capital required.

[9] See Standard and Poor's, *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines*, revised 2 June 2004.

A utility could adapt its actual capital structure to reflect this change, by either issuing debt rather than equity for a period of months or years, or by paying a special dividend (reducing equity) and issuing debt to replace that capital.

The second approach to reflecting the reduction in risk afforded by decoupling is simply to reduce the utility's allowed return on equity, discounting by some number of basis points what would otherwise have been approved. This has been done in a number of jurisdictions. There are, however, several points that regulators should consider when weighing this option against the first. They are discussed in Subsection 3, below.

2. Some Impacts May Not Be Immediate, Others Are

If the rating agencies perceive a risk mitigation measure will be in place for an extended period, they may be willing to recognize the benefit of risk mitigation immediately upon implementation. If the risk mitigation measure is put in place only for a limited period, or the regulatory commission has a record of changing its regulatory principles frequently, the rating agency may not recognize the measure.

If the regulator does *not* change the allowed equity capitalization ratio when a new risk mitigation measure is implemented, the rating agency will eventually realize that the mitigation is occurring, that earnings are more stable, and eventually a bond rating upgrade is possible. Once that occurs, the cost of debt will eventually decline, and consumers will realize the benefit of lower costs of debt in the conventional rate making process.

In theory, the total cost savings from a bond rating upgrade should be about the same as the savings from an equity capitalization reduction. The principal reason for preferring the equity capitalization option is that it can be implemented concurrently with the imposition of the risk mitigation measure, so that consumers receive an immediate economic benefit when the measure is implemented. The lag to a bond rating upgrade can be years – or as much as a decade -- and the cost savings will phase in very slowly as new bonds are issued.

3. Risk Reduction: Reflected in ROE or Capital Structure?

Some ratepayer advocates have proposed an immediate reduction in the allowed return on common equity as a condition of implementing decoupling. This may create controversy in the rate-making process, with the risk that utilities then become resistant to implementation of decoupling. In other jurisdictions, utilities have pointed to past rate cases where many of the "comparable" utilities used to estimate the required return on equity already have risk mitigation measures in place.

Economic theory supports the notion that risk mitigation is valuable to investors, and that value will (eventually) be revealed in some way in the market – through a lower cost of equity, a lower cost of debt, or a lower required equity capitalization ratio. Any of these will eventually produce lower rates for consumers, in return for the risk mitigation measure. Regardless of the economic theory, however, utilities may tend to view a reduction in the return on equity as a "penalty" associated with decoupling. In contrast, a restructuring of the capitalization ratio does not necessarily alter the required return on equity, and it is more directly reflective of the risk mitigation that decoupling actually provides – that is, stabilization of earnings with respect to factors beyond the utility's control. By reducing volatility, the utility needs less equity to provide the same assurance that bond coverage ratios and other financial requirements will be met.

Rating agencies have recognized the linkage between risk mitigation and the required equity ratio to support a given bond rating than to the required return on equity. For this reason, there may be advantages to focusing on the utility's capital structure, rather than on its allowed return on equity or the cost of debt, when regulators consider how to flow through the risk-mitigation benefits of decoupling to consumers when a mechanism is put into place.

4. Earnings Caps or Collars

Some commissions have imposed an earnings cap, or an earnings collar as part of a decoupling mechanism. These ensure that, if earnings are too high above a baseline (or too low below the baseline) the decoupling mechanism is automatically subject to review. Because decoupling reduces earnings volatility, it should be unlikely for earnings to vary outside a range of reasonableness. Therefore such a cap or collar, while unlikely to be triggered, may provide greater comfort with the change represented by decoupling.

E. Rate Design Issues Associated With Decoupling

Decoupling should remove traditional utility objections to electric and natural gas rate designs which encourage energy conservation, voluntary curtailment, and peak load management. Under volumetric pricing without decoupling, utilities have a significant portion of their revenue requirement for rate base and O&M expenses associated with throughput. A reduction of throughput will likely reduce revenues faster than the savings in short-run costs, simply because most distribution, billing, and administrative costs are relatively fixed in the short run.

Conversely, with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity and gas. This can be achieved through energy efficiency investment (with or without utility assistance), through energy management practices (turning out lights, managing thermostats), or through voluntary curtailment.

The best examples of this are the natural gas and electric rate designs used by California electricity and natural gas utilities, where decoupling has been in place for many years. The residential rates applicable to most customers of Pacific Gas and Electric, typical of those of all gas utilities and at least the investor-owned electric utilities in California, are shown below. Both the gas and electric rates are set up with a "baseline" allocation which is set for each housing type and climate zone. Neither rate has a customer charge, although there is a minimum monthly charge for service; if usage in a month falls below the amount covered by the minimum bill, the minimum still applies.

PG&E Natural Gas Rate at May 1, 2008

Rate Element	*Baseline Quantities*	*Excess Quantities*
Minimum Monthly Charge	~$3.00/month	
Base Rate per therm	$1.45131	$1.68248
Multi-Family Discount (per unit per day)	$0.17700	$0.17700
Low-Income Discount (per therm)	$0.29026	$0.33650
Mobile Home Park Discount (per unit per day)	$0.35600	$0.35600

PG&E Electric Rate
Rate E-1 at May 1, 2008

Rate Element	*Low-Income*	*All Other Customers*
Minimum Monthly Charge	~$3.50	~$4.45
Baseline Quantities	$.08316	$.11559
101% - 130% of Baseline	$.09563	$.13142
131% - 200% of Baseline	$.09563	$.22580
200% - 300% of Baseline	$.09563	$.31304
Over 300% of Baseline	$.09563	$.35876

Clearly these rate designs produce a great deal of revenue volatility for the utility. Without decoupling, the utility could face extreme variations in net income from year to year. However, with decoupling, this type of rate design produces very stable earnings. The earnings per share for Pacific Gas and Electric (the utility) for the past three years (since decoupling was restored after the termination of the California deregulation experiment) have been $1.01 billion, $971 million, and $918 million. This stability was achieved despite a $1.4 billion increase in operating expenses, mostly the cost of electricity, during this period.

Revenue stability needs of the company can conflict with principles of cost-causation as they relate to consumers. Utilities are interested in revenue stability so that they have net income which can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or energy conservation efforts of consumers. Cost of service considerations, however, can produce a very different result. To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage and LNG facilities) and those capacity costs are allocated exclusively to excess use in winter and summer months, the cost to consumers of excess usage is dramatically higher than the cost of base usage. A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage that requires that capacity. While this is arguably "fair," doing so can result in serious revenue stability issues for the utility. Decoupling is one way to address the revenue stability issue for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.

Customers also have an interest in bill stability, because in extremely cold winters, their bills can quickly become unmanageable. Absent decoupling, rates such as those used in California, while accurately conveying the real cost of seldom-used capacity, accentuate bill volatility. With decoupling (and budget billing), however, customers can enjoy bill stability at the same time that utilities enjoy revenue stability, without the adverse impacts on usage that a Straight Fixed/Variable rate design can cause.

1. Addressing Revenue and Bill Volatility

There are three principal options typically proposed to address the problem of revenue and bill volatility. These include decoupling, Straight Fixed/Variable rate design, and budget billing programs. Budget billing is typically offered by utilities regardless of rate design, and we will consider it beyond the scope of this review. Straight Fixed/Variable rate design is discussed below, under Alternatives to Decoupling.

2. Rate Design Opportunities

In 1961, James Bonbright published what is considered the seminal work on ratemaking and rate design for regulated monopolies. His context was, of course, traditional price-based regulation, and he identified ten principles, some of which are in tension with each other, to guide the design of utility prices. Three in particular—on the one hand, rates should yield the total revenue requirement and they should provide predictable and stable revenues and, on the other, they should be set so as to promote economically-efficient consumption—demonstrate that tension.[10] In certain instances, more economically efficient pricing structures could lead to customer behavior that in turn results in less stable and, in the short run, significant over- or under-collections of revenue. Decoupling mitigates or eliminates the deleterious impacts on revenues of pricing structures that might better serve the long-term needs of society. Some innovative rate designs that regulators may want to consider with decoupling include the following

a) Zero or Minimal Customer Charge

A zero or minimal customer charge allows the bulk of the utility revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental costs.[11] During the early years of the natural gas industry, this type of rate design was almost universal, as the industry was competing to secure heating load from electricity and oil, and imposing fixed customer charges would have disguised the price advantage they offered and confused customers. Simple commodity billing was the easiest way to make cost comparisons possible for consumers. As natural gas utilities have taken on more of the characteristics of monopoly providers, they have sought to increase fixed charges.

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[10] Bonbright, James C., *Principles of Public Utility Rates* (Public Utilities Reports, Inc., Columbia University Press, New York, 1961), p. 291.

[11] For electric utilities depending on coal for the majority of their supply, valuing CO_2 at the levels estimated by the EPA to result from passage of the Warner-Lieberman bill (in the range of $30 - $100/tonne) would add up to $.05/kWh to the variable costs of electricity. For natural gas utilities, the environmental costs of supply are on the order of $0.30/therm, or approximately equal to total distribution costs for most gas utilities. See http://www.epa.gov/climatechange/economics/economicanalyses.html.

The California utilities, under decoupling, have retained zero or minimal customer charges.

b) Inverted Rate Blocks

Inverted block rates, of the type shown above for Pacific Gas and Electric Company, serve several useful functions. First, they align incremental rates with incremental costs, including incremental capacity, energy and commodity, and environmental costs. They serve to encourage energy efficiency and energy management practices by consumers. However, they reduce net revenue stability for utilities by concentrating recovery of return, taxes, and O&M expenses in the prices for incremental units of supply, which tend to vary greatly with weather and other factors.

c) Seasonal Rates

Seasonal rates are typically imposed by utilities with significant seasonal cost differences. For example, a gas utility with a majority of its capacity costs assigned to the winter months will typically have a higher winter rate than summer rate. With traditional regulation, seasonal rates reduce net revenue stability for utilities, by concentrating revenue into the weather-sensitive season.

3. Summary: Rate Design Issues

The hypothetically "correct" rate design for an electric and gas utility can be a customer charge that recovers metering and billing costs (these are both incremental and decremental with changes in customer count), and an inverted block rate design based on the load factors of typical end-uses. The California rates shown above for Pacific Gas and Electric contain these characteristics.

For electric utilities, lights and appliances have steady year-round usage characteristics, and therefore the lowest cost of service. For gas utilities, water heating, cooking, and clothes drying have steady year-round usage characteristics. For both types of utilities, space conditioning (heating and cooling) loads, which are associated with the upper blocks of usage, have the lowest load factors, and therefore the highest cost of service.

Taking a hypothetical electric utility, with typical meter reading and billing costs, capacity costs of $15/kW per month and energy costs of $.05/kWh, produces the following cost-based rate design:

Rate Element	Load Factor	Capacity Cost	Energy Cost	Total Cost
Customer Charge				$5.00
First 400 kWh Lights/Appliances	70%	$.03	$.05	$.08
Next 400 kWh Water Heat	40%	$.05	$.05	$.10
Over 800 kWh Space Conditioning	20%	$.10	$.05	$.15

Establishing theoretically correct rate designs such as those imposed by Pacific Gas and Electric provides consumers with very clear economic signals about the costs their usage imposes, but evidence in California is that even with these high prices, utility energy efficiency programs are an essential element of a successful energy policy. The inverted rates tend to drive consumers to the programs, but if the programs are not available, they may be unlikely to respond to the incremental prices.

Decoupling is a tool that allows the utility's interest in stable net revenues, the consumer's interest in stable bills, and the society's interest in cost-based pricing to be met. Under decoupling, the utility can implement an inverted rate, knowing that lost distribution revenues that are incurred when sales decline will be recovered. If implemented on a "current" basis as proposed in Section IV of this report, decoupling can also stabilize customer bills, by reducing the unit rates in months when extreme weather causes a significant variation in sales from the levels assumed in the rate case where rates are set.

F. Alternatives to Decoupling

The principal goal of decoupling is to remove the disincentive to investment in energy efficiency that exists when utility net income is tied to sales volumes. There are a number of other tools that regulators have employed to address this concern. Each has potential advantages over decoupling, but each also has limitations on how well it addresses the principal regulatory goals of decoupling.

1. Lost Margin Recovery Mechanisms

A lost margin recovery mechanism compensates the utility for the sales margin lost when consumers take advantage of utility energy conservation programs. The advantage of these mechanisms is that they only compensate the utility for margin lost as a result of utility programs, and consumer advocates sometimes favor this limited cost recovery.

Experience with lost margin recovery in Hawaii from 1992 to 2005 demonstrated several shortcomings.

First, lost margin recovery does not affect the throughput incentive: if the utility's short-run marginal cost is lower than its retail rate, it still profits when sales increase. The incentive, therefore, is to fund programs which produce theoretical savings (generating lost margin recovery) but not actual savings.

Second, the utility may have a powerful incentive to discourage energy efficiency that does not involve utility programs. For example, the utility might receive lost margin recovery when builders accept utility incentive payments to build more efficient homes, but would resist improved energy codes, since these would also produce lower margins per customer, but would not fall into the "utility program" limitation of the lost margin mechanism. The result would be to encourage high-cost conservation while discouraging low-cost energy code improvements.

Finally, lost margin mechanisms are very tedious, requiring an estimate of the energy savings from each utility conservation program, and, in some cases, a separate calculation of how many customers would have utilized similar conservation measures in the absence of a utility program (isolation of free riders). While conservation evaluation has become an advanced science, this is a very time-consuming element of lost margin mechanisms.

2. Frequent Rate Cases, Multi-Year Rate Cases

If rate cases are held frequently, utilities do not suffer lost margins from energy efficiency programs for very long. In future test year jurisdictions, such as Minnesota, annual rate cases would, in theory, completely eliminate any lost margins. However, the incentive between rate cases would remain the same – if short-run marginal costs are lower than retail rates, the incentive is to increase throughput.

3. Straight Fixed-Variable Rate Design

Natural gas utilities frequently advocate Straight Fixed-Variable (SFV) rate design as a tool to stabilize income, and also argue that this would eliminate the throughput incentive, removing the barrier to utility-funded conservation efforts.

SFV rate design imposes a fixed charge to customers which is designed to recover all "fixed" costs. The definition of fixed costs in this context typically goes far beyond the accounting definition of fixed costs (interest and depreciation) to include the return on equity, plus the bulk of distribution operation and maintenance expenses, and federal and state income taxes.

An SFV rate design might have the following rate form:

Rate Element	Price per Unit
Customer Charge / month	$30.00
Distribution Charge / therm	$0.00
Gas Supply Charge / therm	$1.00

This type of rate design is almost unheard of in competitive industries, because it would chase away profitable customers. Hotels have high fixed costs, but recover their costs per room-night. Airlines have high fixed costs, and recover their costs from each ticket sold. Oil refineries have immense fixed costs (as do oil pipelines, oil product pipelines, and gasoline retailers), but all of these costs are recovered per-gallon. Even in the telecommunications industry, as dominant carriers have succeeded in implementing rates with high fixed charges, wireline access lines have actually begun to decline, reversing a 100-year upward trend. This type of pricing has spurred the development of an entire group of prepaid wireless competitors offering basic telephone service for $5 - $10/month with limited calling.

There are several problems with SFV rate design. First and foremost, it adversely affects small users. These are not universally low-income consumers; but, for the majority of low-income users, who do use less than the average amount of energy, SFV could have a disproportionately large negative impact. Second, it adversely affects residents of multi-unit and multi-family housing, who typically have lower-than-average costs of distribution service due to their proximity to other customers, but also have lower-than-average usage per unit. Many of the residents of multi-family housing are low-income or fixed-income seniors.

Perhaps most important, SFV pricing shifts costs of seldom-used peaking capacity (distribution main capacity and LNG peaking facilities) from heating consumption during extreme weather to usage of non-heating customers, and non-heating usage of all customers. It results in a mismatch of cost causation and cost recovery.

a) Elasticity Impacts of Straight Fixed-Variable Pricing

Perhaps the most serious adverse societal impact of SFV is the increased energy consumption that is expected to result from reducing the variable component of pricing. In a simplified example, shown in Appendix F, a shift from pure volumetric pricing to pure SFV pricing could result in an 18% increase in the quantity of natural gas required to meet customer needs, even with continued volumetric pricing of gas commodity. This elasticity effect could more than negate the savings from all utility energy efficiency programs.

b) Cost of Capital Impacts of Straight Fixed-Variable Pricing

SFV pricing, like decoupling, eliminates utility earnings variability due to sales volume changes. Like decoupling, SFV pricing leaves earnings variation due to inflation, cost controls, changes in interest rates, and other causes unaffected. The cost of capital effect of SFV pricing should be expected to be similar to that for decoupling.

4. Weather-Only Normalization

Many natural gas utilities have weather-only normalization mechanisms that adjust rates up in mild weather, and down in severe weather. These serve much of the function of decoupling in stabilizing both utility income and customer bills (if done in real-time). They do not reduce the throughput incentive, however, since weather-only normalization mechanisms only adjust for changes in weather, not for changes in sales volumes due to other causes. The weather adjustment factors are set in the rate case, based on test-year values. Any reduction in sales due to conservation would be uncompensated.

5. Real-Time Pricing

Academic economists frequently advocate real-time pricing (changing retail prices instantly to reflect changes in wholesale market conditions) as the cure for all ills that regulation allows. Real-time pricing is typically based on short-run marginal costs, when consumer investment in energy efficiency should be encouraged based on long-run costs (including the cost of externalities). In addition, extensive experience has demonstrated that there are significant barriers other than price to consumer-initiated investment in energy efficiency. Real-time pricing cannot be expected to produce the same level or type of energy efficiency investment and response that utility programs can produce.

6. Moving Efficiency Outside the Utility

Vermont, New York, Oregon, Wisconsin, and Hawaii have approved the establishment of energy conservation organizations, funded through utility charges, but organizationally distinct from the utilities. The energy conservation organizations receive funding, make expenditures, and are accountable to regulators, but are not also electric or natural gas utilities, and therefore have no concern about lost distribution margins. Their incentive (to retain their status) is to deliver reliable and economic efficiency savings.

This option avoids the utility's disincentive for investment in energy efficiency by removing the utility's role in energy efficiency, except as a revenue collection mechanism, but does not cure the throughput issue and the associated impacts on the utility's revenues. It can also eliminate the risk of disallowances of energy efficiency investments, a minor risk given the level of oversight of most utility programs.

One disadvantage of moving energy efficiency programs outside the utility is that coordination with utility distribution planning is inevitably weakened. Utility-operated efficiency programs can focus on localized areas where significant distribution reinforcement is pending, avoiding not only production and transmission costs, but also distribution costs and losses. While it is theoretically possible for regulators to adopt policies to assure a high level of coordination, it may not be as effective as when the utility is operating the programs itself.

7. Elimination of PGAs and FACs

One of the earliest publications of the Regulatory Assistance Project founders detailed how fully-reconciled fuel and purchased power adjustment clauses for electric companies (FACs) and purchased gas adjustment clauses for gas utilities (PGAs) can have the effect of making every incremental sale profitable, and every sale lost to conservation unprofitable.[12] This is achieved by flowing through to all customers the incremental cost of additional resources, even when the retail price is lower than the incremental cost. For example, when utilities use fuel oil or diesel peaking generation sources, the high incremental costs of these sources are generally not directly translated into peak rates for customers. Instead, the FAC allows the cost of this high-priced power to be averaged into all sales, and the costs recovered. Thus, the utility can "make money" by producing power at an incremental fuel cost of \$0.12/kWh, even though it sells that power for \$0.08/kWh.

One alternative to decoupling would be to eliminate the PGA or the Fuel Adjustment Clause. This would eliminate this "guaranteed profitability of additional sales." This is unlikely to produce major benefits for energy efficiency, simply because there are

[12] See: Moskovitz, *Profits and Progress through Least- Cost Planning*, NARUC, 1989, p. 4: "In its understandable quest to maximize profits, a utility's most powerful incentive for selling more electricity is hidden in its regulatory fuel adjustment clause."

relatively few hours in which the short-run marginal cost is higher than the retail rate, and most conservation measures save energy over a broad spectrum of the utility load duration curve.

Elimination of the PGA or FAC for Minnesota utilities would, however, increase their exposure to cost volatility over which they have limited control. It would also increase the perceived financial risk of the utilities. In essence, this could have the opposite effect on the cost of capital to that of decoupling.

G. Performance Incentives

Incentives for superior performance can be used under traditional regulation as well as under decoupling. They may not, however, elicit the same responses in both cases. Commissions have attempted several types of incentives for energy efficiency in the past, and the results have been mixed.

1. Rate-of-Return Incentives

A rate of return incentive is a bonus to the allowed rate of return for energy efficiency programs. It can be tied to the level of investment (higher allowed return on equity for energy efficiency investments) or tied to the level of performance (a bonus based on achieving specific targets).

Experience with rate of return incentives has been mixed. In Washington, a 2% bonus rate of return incentive was in place from 1980 to 1990. By 1990 it was evident that the incentive was for the utility to spend as much as possible on programs that saved as little energy as necessary. One utility was found to be spending 50% of its residential energy efficiency budget subsidizing heat pumps, primarily in mobile home parks where natural gas service was not (yet) available. The clear goal of the electric utility was to retain the heating load, and to derive a bonus on its return on equity for doing so.

A rate of return incentive can work with a decoupling mechanism. The decoupling mechanism would eliminate the throughput incentive, while the rate of return incentive would provide a positive reward for conservation performance. However, tying the reward to the amount invested has the potential to lead to suboptimal investment plans.

2. Shared Savings Mechanisms

A number of states, including Minnesota, have established shared savings plans for energy efficiency. In theory, these can be large enough to overcome the throughput incentive – the "Save-a-Watt" program proposed in 2007 by Duke Power in North Carolina would provide the utility with 90% of the "avoided cost" for all sales avoided by utility conservation programs. Given that the avoided cost is the cost of a new nuclear, coal, natural gas, or renewable energy generator, and the cost of most energy conservation measures is 20% to 50% of this avoided cost, the Duke approach could be highly lucrative to shareholders, and likely overpower the throughput incentive. The Save-a-Watt approach increases the effective cost of energy efficiency from about $0.02-$0.03/kWh to as much as $0.08-$0.10/kWh (or more).

A modest shared savings mechanism, combined with a decoupling mechanism, would be likely to produce at least equal performance, at a dramatically lower cost to consumers. For example, a decoupling mechanism could make the utility "whole" when customers use less power or gas (for any reason), while a shared savings mechanism that gives the utility 10% of the savings from energy efficiency programs would provide an incentive for the utility to fund all cost-effective programs.

III. Recommendations: Criteria and Standards by Which to Design and Evaluate a Decoupling Proposal

Section 216B.2412 states that the Commission "shall, by order, establish criteria and standards for decoupling. The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 without adversely affecting utility ratepayers. In designing the criteria, the commission shall consider energy efficiency, weather, and cost of capital, among other factors."

We see two broad categories of criteria and standards, and have organized our discussion along their lines. The first are the minimum design and informational requirements that a decoupling proposal should satisfy in order to be considered for approval by the Commission. The second are those that the proposal would have to meet before the Commission would approve it.

A. Elements to be Included in a Proposal

In the following subsections, we list the elements that a decoupling proposal should at a minimum include. They consist of both informational (i.e., filing) requirements and substantive design features.

1. Objectives

The proposal should begin with a set of clearly defined goals for the decoupling regime. What are the reasons for it, and why is it likely that the proposal will achieve these ends more efficiently than other forms of regulation? Among such objectives are:

- Risk reduction – and corresponding cost reductions – for consumers and shareholders;
- Increased investment in least-cost resources, in particular energy efficiency, thereby reducing the long-term costs of serving load;
- Increased efficiency in utility operations and management; and
- Objective analysis of other cost-effective energy-saving opportunities, including fuel-substitution, for consumers.

2. Description of the Decoupling Method

The mechanics of the decoupling proposal must be explained in detail. Elements to be described will include at least the following:

- *The mathematics of the mechanism.* How are revenues decoupled from sales, e.g., by revenue per customer, as a pre-determined annual revenue requirement (i.e., future test year), or in some other fashion? Is it full, partial, or limited decoupling?
- *Decoupling adjustments.* How will actual revenues be reconciled with allowed revenues? How often will the decoupling adjustments be made? Monthly (i.e. on

a billing cycle basis), quarterly, semi-annually, annually? Will they be applied on a customer-class basis or equally across all customer classes?

- *Timing:* Will the decoupling adjustments be implemented in the month in which sales volumes deviate from test year volumes, or will differences accrue and be deferred for later collection/rebate?
- *Term.* When will the decoupling program end? Are there provisions for renewal, including a full investigation of the underlying cost of service? Under what conditions, if any, can the decoupling program be prematurely terminated, and what actions (including a general rate case) can, or should, then be taken? Are the answers to these questions different if the initial decoupling proposal is for a "pilot program"?
- *Implementation.* When and how will the decoupling mechanism be implemented. For example, should implementation occur only in a rate case, or within a limited period of time after a rate case?

3. Revenue Requirement

If the proposal is submitted separately from a general rate case, does the proposed revenue requirement reflect a downward cost-of-capital adjustment?
If the proposal calls for a multi-year decoupling proposal, the means by which the allowed revenue will be adjusted in each of the later years, if at all (as distinguished from the decoupling adjustments themselves, e.g., numbers of customers), should be detailed. Such adjustments could be made through regular proceedings ("attrition cases," as in California) or through a mathematical overlay that might account for productivity gains, inflation, and a limited set of factors (sometimes referred to as "exogenous") whose cost impacts are not immediately captured in the other measures.[13]

4. Cost of Service

The decoupling proposal should be accompanied by a detailed class cost of service analysis.

To the extent that the decoupling mechanism is limited to certain classes of customers, the cost of service analysis should show how cost-of-capital benefits are flowed through to the participating classes.

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[13] An example of a formula for adjusting a revenue requirement or an allowed revenue-per-customer figure is the following:

$$RPC_{t+1} = [RPC_t * (1 + i - p)] \pm Z$$

Where,

RPC_t = revenue requirement in year t
i = inflation rate
p = productivity rate
Z = exogenous costs, if any

The inflation rate would be a national measure of general changes in price levels in the economy, appropriate for the sector in question, e.g., the CPI-U. The productivity adjustment would be based on the industry average for similar firms. Exogenous costs might be the significant changes in the tax code (before they are captured by the inflation measure) or out-of-the-ordinary expenses for storm damages.

5. Energy Efficiency, Rate Design, and Other Public Policy Objectives

Because, under the Minnesota legislation, decoupling is seen as a means of overcoming utility disincentives to promote energy efficiency, it is imperative that a proposal explain how decoupling will advance the state's efficiency goals. Specifically, the proposal should include design details, including performance targets, incentives, and penalties, for programmatic efficiency efforts.[14]

Also to be considered are changes in retail rate designs that better relate the long-run costs of service to demand, thus better informing customers of the economic impacts of their consumption decisions. These could include, for natural gas service, reduced customer charges, adjustments to hook-up fees, and increased unit-based delivery and commodity charges. For electric service, more dynamic (time-sensitive) pricing structures, such as critical peak and even real-time pricing, and innovative tariffs for users with on-site generation, could be implemented. Oftentimes, the adoption of a new rate structure causes short-term revenue problems – over- or under-collections in particular rate classes. Decoupling relieves some of the pressure to assure revenue-neutrality for the class in question, when the new pricing goes into effect.

6. Service Quality Standards

A decoupling proposal should include a detailed set of service quality standards, and a schedule of penalties for failing to meet them. The standards to be measured should include, among others, numbers of outages, durations of outages, customer service response times, missed appointments for service or installations, the intervals between requests for new service and the provision of service, and numbers of disconnections.

Under traditional regulation, utility revenues fall when there are outages. Customers do not pay for services that they do not receive. Moreover, the utility has no recourse to collect such revenues foregone.[15] To the degree that outages and other customer inconveniences are due to the utility's own failures, regulators can take remedial action, in the form of financial penalties and other directives. But, it can be argued that the prospect of lost revenues is, by itself, a sufficient inducement to assure reasonable levels of customer service.

Some participants wondered whether decoupling, in particular full decoupling, undermines the utility's incentives to provide customer service, since it assures specified levels of revenue recovery regardless of actual sales. The concern is that the revenues foregone from an outage would simply be recovered from all other customers through the decoupling adjustment, and the company's enthusiasm to swiftly make repairs, maintain

[14] Several participants in the workshops and meetings noted that Section 216B.2412 does not answer the question of whether efficiency savings should, under a decoupling regime, exceed those that are expected under traditional regulation and given the current, legislatively mandated savings and spending levels. This is a question that the PUC will need to address.

[15] Except, perhaps, insofar as the outage is the result of an extraordinary event—say, a violent storm—over which the company had no control and whose financial consequences threaten the company's ability to provide safe, adequate, and reliable service going forward.

its system to the highest standards, ensure reliability, and provide a sufficient level of power quality would wane. While there is a logic to this line of thinking, we doubt that decoupling, by itself, would lead to an erosion of customer service (and, indeed, we've seen no evidence of it in other jurisdictions). Public opinion, general regulatory oversight, and the utility's corporate culture are probably sufficient to prevent it. Even so, customer service standards make sense as a general matter, particularly in conjunction with a multi-year rate plan. Consideration of a decoupling proposal provides an opportunity to develop and implement such standards, if they are lacking.

7. Existing Revenue Adjustments

A proposal should explain how current adjustments to collected revenues will be treated under the decoupling regime.

Today there are a number of adjustments that are made to the rates charged by Minnesota gas and electric utilities to assure the allowed amounts of money are collected to cover specified expenses. The natural gas commodity is one such expense, fuel and purchased power for electric generation are another. Costs associated with utilities Conservation Investment Programs are also collected in this fashion. The general intent of these adjustments is, in effect, to decouple the revenues associated with the expense from sales levels, while leaving the utility's base revenue requirements at risk. Indeed, this is a kind of partial decoupling.

It is likely that most, if not all, non-commodity adjustments can be eliminated under a decoupling program. This, of course, will depend upon the specifics of each adjustment (i.e., the manner in which it is made, the purpose it serves, the degree to which the utility can efficiently manage the cost under a revenue cap and whether the public good is advanced by its doing so, etc.), upon the nature of the decoupling regime (full, limited, or partial), and upon any law that governs them.

8. Reporting and Evaluation

A decoupling proposal should be accompanied by a plan for evaluating its efficacy. A prerequisite to the plan will be a defined set of reporting requirements. What information should be made available that either is not currently being collected or is not managed in a fashion most useful to an assessment of ratemaking methods? Among the categories of data to be provided should be the following:

- *Revenue Comparisons.* How would revenues under traditional regulation have differed from those collected under the decoupling regime? What are the relatives effects of efficiency programs, actual weather (to the extent that there is not a weather adjustment under traditional regulation), and other factors on revenues.
- *Bill Comparisons.* A corollary to the question of revenues is that of customer bills. How have average bills differed from those under traditional regulation?
- *Energy Efficiency.* Is the company meeting its energy efficiency savings goals? Has energy efficiency achievement been enhanced under the decoupling mechanism?

- *Service Quality.* Is the company meeting its service quality targets? Has service quality declined?
- *Risk.* Has the decoupling regime stabilized revenues as expected and, if so, how has this affected the utility's overall risk profile?

9. Customer Information

The proposal should describe how customers will be informed of the decoupling program, how it works and what it means for them, and how the adjustments will be made on their bills.

B. Criteria by Which to Evaluate a Proposal

The criteria for evaluating a decoupling proposal, or any proposal to reform regulatory methods, should be should be framed with an eye to the alternatives (including traditional regulation). Is it more likely than the alternatives to achieve stated public policy goals? Thus, the evaluation is essentially comparative in nature. Regulators should test a proposal against the following criteria:

- *Objectives:* Are the objectives that have been set out for the decoupling program appropriate? Is the proposal likely to achieve them? Will it achieve the overarching goal of aligning the utility's financial incentives with the state's public policy objectives? Is it more likely to do so than the alternatives? Will the general good of the state be promoted by it?
- *Revenue Requirement:* Will this form of regulation result in a lower long-run cost of service, and therefore a lower revenue requirement, than the alternatives?
- *Just and reasonable rates:* Will the rates charged under the decoupling regime be just and reasonable?
- *Quality of service:* Will service reliability and quality deteriorate, remain the same, or improve under the decoupling program?
- *Efficiency:* Is the decoupling program accompanied by a meaningful increase in the utility's investment in energy efficiency resources, above and beyond that which is required by Minn. Stat. § 216B.2401[16] and Minn. Stat. § 216B.241, subd. 1c(b)[17]?
- *Other public policy goals:* Will decoupling inhibit or advance achievement of other public policy aims, such as infrastructure development and emissions

[16] 216B.2401 ENERGY CONSERVATION POLICY GOAL.

It is the energy policy of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design, and indirectly through energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

[17] 216B.241 ENERGY CONSERVATION IMPROVEMENT

Subd. 1c. (b) Energy-saving goals. (b) Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather normalized average.

reductions? How will the decoupling plan affect the utility's ability to achieve these objectives?

- *Simplicity and ease of administration:* Will administration of decoupling be significantly more difficult than traditional regulation? How will it affect resource needs at the Commission and other state agencies? Will the program be easy to administer, both for the utility and the regulators?
- *Transparency:* Will the mechanics of the decoupling be easily discerned? Will the calculations of the adjustments be easy to understand and follow?
- *Comprehensibility:* Is the program easily understood? Can its features be easily communicated? Has the utility designed a satisfactory public information campaign to explain it to consumers?
- *Consequences:* What is the likelihood of unwanted outcomes (e.g., significant over- or under-earnings)? Is it greater than under the alternatives?
- *"Off-Ramps"*: Does the mechanism have a pre-determined set of conditions under which it would self-terminate or be subject to regulatory review if the impacts are significantly different from those anticipated at approval?

IV. Straw Proposal

This straw proposal is a concept that seeks to design a natural gas utility decoupling mechanism that incorporates the best features of the decoupling plans now in operation, and takes into account comments heard from participants in the Minnesota workshop.

Revenue per Customer Decoupling, With Separate Old/New Customers Revenue Per Customer Values: The utility distribution revenue requirement will be the sum of the allowed revenue requirement from the rate case, plus the product of customer growth since the test year and the average incremental distribution revenue of new customers. The old/new distinction is designed to recognize that new homes built to modern codes use less natural gas and would contribute lower revenues.[18]

Classes to be Included: At a minimum, the pilot program shall include the residential and small commercial class(es) of customers. Additional classes may be included in the pilot proposal. As an alternative, the Commission may consider extending the pilot to all firm service customers.

Current (not accrual) Decoupling: The decoupling adjustment shall be calculated for each billing cycle, based on actual throughput versus rate case normalized throughput adjusted for new customer volumes. Average monthly revenue per customer shall be determined from general rate case data, and pro-rated across billing periods that span adjacent months.

Rate Design: The utility shall file a rate design with a customer charge that does not exceed the cost of metering, meter reading, and billing expenses. All other costs shall be reflected in a volumetric distribution charge. The PGA mechanism shall continue to be computed monthly.

Cost of Capital: If filed independently of a general rate case, the filing shall incorporate a 1% reduction in the distribution revenue requirement to the classes included in the pilot, to reflect a portion of the lower financial risk resulting from decoupling. If filed in the context of a general rate case, the lower financial risk resulting from decoupling shall be reflected in the utility's proposal and can be addressed by the parties in the rate case. The benefits of the reduced financial risk shall be reflected in the revenue requirement (whether through a lower ROE, an imputed capital structure, or some other means) of the classes of customers included in the pilot program.

Rate Cap: During any 12 month period, the total rate surcharges shall not exceed 3% of the test year revenue requirement. Any decoupling adjustments in excess of this amount shall be deferred, and be recoverable only after a Commission investigation into whether the mechanism is operating properly, providing recovery of lost distribution margins, but not producing windfalls.

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[18] If these new homes do not provide enough revenue to justify line extensions, the line extension policy is the appropriate tool to address this revenue shortfall, not the rate design or decoupling mechanism.

Duration: The filing shall contain a termination date not more than thirty-six months after the effective date. A general rate case filing is required to re-enact the decoupling mechanism.

Service Quality Index: A service quality index, with penalties up to 3% of gross revenues for performance that deteriorates from a baseline period, shall be included in the pilot. Elements to be included in the index shall include, at a minimum, the following elements:

- Time to answer a telephone call for customer service during business hours
- Time to respond to gas emergency calls
- Missed appointments for service or installations
- Time to reconnect service after conditions of restoration are met
- Number of customers disconnected for non-payment

Review Process: After twelve months of operation, the Commission shall conduct a limited review of performance, to determine if the mechanism is generally meeting expectations. If evidence indicates that there is a significant difference between expectations and results, the Commission may terminate or modify the pilot.

After 24 months of operation, the Commission shall conduct a more comprehensive review of the pilot program to determine if the program should be continued with or without modification after the pilot period ends. Parties and interested persons may make recommendations as to the scope of the review and the means by which it is carried out, but the Commission shall make the final decisions in these respects. The results of the evaluation shall inform future utility decoupling proposals.

V. Appendices

A. Minnesota Statutes, Section 216B.2412

216B.2412 DECOUPLING OF ENERGY SALES FROM REVENUES.

Subdivision 1. **Definition and purpose.** For the purpose of this section, "decoupling" means a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency.

Subd. 2. **Decoupling criteria.** The commission shall, by order, establish criteria and standards for decoupling. The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 without adversely affecting utility ratepayers. In designing the criteria, the commission shall consider energy efficiency, weather, and cost of capital, among other factors.

Subd. 3. **Pilot programs.** The commission shall allow one or more rate-regulated utilities to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation. Each pilot program must utilize the criteria and standards established in subdivision 2 and be designed to determine whether a rate-decoupling strategy achieves energy savings. On or before a date established by the commission, the commission shall require electric and gas utilities that intend to implement a decoupling program to file a decoupling pilot plan, which shall be approved or approved as modified by the commission. A pilot program may not exceed three years in length. Any extension beyond three years can only be approved in a general rate case, unless that decoupling program was previously approved as part of a general rate case. The commission shall report on the programs annually to the chairs of the house of representatives and senate committees with primary jurisdiction over energy policy.

B. The Throughput Incentive, Costs, and the Rationale for Decoupling

All regulation rewards behavior of one kind or another. Any method of cost recovery through a regulatory process provides a set of incentives to which the regulated companies will respond. Understanding how utilities make money is essential to the design of public policy: a policy is more likely to be successful if it is not in tension with the financial interests of those directly affected by it.

Rate-of-return ratemaking as it has been practiced for more than a century is an exercise in price-setting. During that time, traditional regulation has effectively controlled monopoly power and facilitated the creation of the world's most advanced electric system, with service available virtually everywhere throughout the country, and the expansion of a reliable natural gas network from coast to coast. The steady improvements in technology and the decades of economies of scale to be captured meant that costs, in real terms, declined over much of the twentieth century, but also hid a significant drawback of price-based regulation, namely, that it lacks strong incentives to promote the overall efficiency of the electric and gas sectors.[19]

Under the traditional ratemaking, the revenues of a monopoly electric company are determined by its level of sales (revenues = price * sales). Given this, electric utilities increase their profits by doing two things: (1) improving the operational efficiency (i.e., reducing the costs) of supply and delivery and (2) increasing sales. While improving the efficiency of utility operations is a good thing, it is not the only thing. Policy should promote not only the efficiency of supply, but efficiency altogether – that is, the efficiency of both supply and demand. Because electricity and, in some cases, natural gas are intermediate goods in the economy – they are used to produce other goods and services that consumers demand – it is not the case that increasing production of electricity, though profitable for utility companies, is necessarily the most efficient (or least costly) means of meeting demand for the goods and services these commodities produce. As experience in Japan, Germany, California, and elsewhere has shown, reducing the energy intensity of an economy (Btu input per unit of GDP output) improves its efficiency and competitiveness, and makes it more resistant to the cataclysmic impacts of energy supply constraints.

Because under traditional regulation the revenues of a monopoly utility are a function of its sales, almost any reduction in sales will result in reduced profits for the company.[20] So, for example, DSM investment may be much less costly than additional supply, but, for the utility, adding supply means increased sales and increased revenue. Generally, the added revenue exceeds the added cost, so the grid utility's profits will increase when it chooses to increase supply. In contrast, the lower cost DSM option reduces sales and revenues. Even if the cost of DSM is zero, the lower revenue means that the DSM option reduces the grid utility's profit. This is a very powerful disincentive for grid utility investment in DSM.

The following tables illustrate this phenomenon. Table 1 summarizes the financial characteristics of a hypothetical, mid-sized electric or gas distribution company. Given test year sales levels and the company's known and measurable costs, it should earn $9.9 million. But sales and circumstances never match test-year assumptions, and changes in sales, for whatever reason, can have significant impacts on a company's bottom line.

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[19] The most fundamental flaw of rate-of-return regulation, the incentive for utilities to gold-plate their systems, was recognized long ago. See, e.g., Averch, Harvey; Johnson, Leland L., *Behavior Of The Firm Under Regulatory Constraint* (American Economic Review, Dec 1962, Vol. 52 Issue 5), p. 1052*ff*.

[20] This is because, in most hours of the day, the marginal cost to produce and deliver a kilowatt-hour or therm is *less* than the marginal revenue received for that kilowatt-hour or therm. This inhibits a company from supporting investment in least-cost energy resources, when they are most efficient, and encourages the company to promote incremental sales, even when they are wasteful.

Table 1

Assumptions						
Operating Expenses	$160,000,000					
Rate Base	$200,000,000					
Tax Rate	35.00%					
			Wtd. Cost		Dollar Cost Amt.	
Cost of Capital	% of Total	Cost Rate	Pre-tax	After-tax	Pre-Tax	After-tax
Debt	55.00%	8.00%	4.40%	2.86%	$8,800,000	$5,720,000
Equity	45.00%	11.00%	4.95%	7.62%	$9,900,000	$15,230,769
Total	100.00%			10.48%		
Revenue Requirement						
Operating Expenses	$160,000,000					
Debt	$5,720,000					
Equity	$15,230,769					
Total	$180,950,769					
After-Tax Earnings	$9,900,000					

Table 2 shows the effects (all else being equal) of changes in sales, both up and down, on the company's earnings. In this example, a one-percent change in sales results in a roughly ten-percent change in earnings. Actual numbers will vary depending on a company's actual costs of service, but the essential finding – that impact on earnings will be disproportionately greater than the change in sales – will hold in all cases. This flows directly from the fact, noted earlier, that a utility's costs do not vary much at all with sales in the short run.

Table 2

	Revenue Change		Impact on Earns		
% Change in Sales	Pre-tax	After-tax	Net Earnings	% Change	Actual ROE
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	-59.40%	4.47%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	-47.52%	5.77%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	-35.64%	7.08%
-2.00%	-$3,619,015	-$2,352,360	$7,547,640	-23.76%	8.39%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	-11.88%	9.69%
-0.00%	$0	$0	$9,900,000	0.00%	11.00%
1.00%	$1,809,508	$1,176,180	$11,076,180	11.88%	12.31%
2.00%	$3,619,015	$2,352,360	$12,252,360	23.76%	13.61%
3.00%	$5,428,523	$3,528,540	$13,428,540	35.64%	14.92%
4.00%	$7,238,031	$4,704,720	$14,604,720	47.52%	16.23%
5.00%	$9,047.538	$5,880,900	$15,780,900	59.40%	17.53%

The challenge for regulators, therefore, is to design a method of setting utility prices and revenues that rewards utilities for taking actions that also improve the economy and welfare of their customers. Put another way, what manner of regulation will make utility companies most profitable by achieving specified public policy objectives? How can regulators align the financial incentives of utilities with the interests of customers and the nation as a whole?

In 1989, recognizing that investment in end-use energy efficiency was at odds with the "throughput incentive" that price-based regulation gives utilities, the National Association of Regulatory Utility Commissioners adopted a resolution urging state commissions to "adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action."[21] In the years that followed, many states experimented with different approaches to deal with the problem – mostly, net lost revenue recovery, performance-based incentives and, more recently, decoupling, as state interest in substantial increases in efficiency investments has grown.

Revenue decoupling breaks the mathematical link between sales volumes and revenues (and, ultimately, profits). It makes revenue levels immune to changes in sales volumes. It enables the utility to recover its prudently incurred costs, including return on investment, in a way that doesn't create perverse incentives for unwanted actions and outcomes. It has two objectives: one, to protect the utility from the financial harm associated with least-cost actions and, two, to remove the utility's incentive to increase profits by increasing sales. And, because it is revenues, rather than earnings directly, that are decoupled, the utility's incentive to improve its operational and managerial efficiency is preserved. The utility benefits from managing its costs wisely.

Regulation is most successful when it links utility revenues to the costs and risks that a company faces. What is it that drives utility costs? In the long-run, of course, the primary driver is demand for energy service (therms and kilowatt-hours); without it, there would be no costs incurred.[22] But in the short-run (the rate-case horizon), utility costs vary more directly with numbers of customers than with sales or, where customer growth is relatively flat, with the need to replace aging, depreciated assets. This is particularly true of unbundled distribution service, where the short-run marginal costs of delivery are, on average, very low or nil, but for which the costs of acquiring and serving customers are significant and recurring. A revenue cap that is can be adjusted for these factors (e.g., a per-customer revenue cap or even a forecast of yearly revenue requirements), more closely links utility remuneration to the near-term costs and risks that the company faces.

It is through rate design that the long-term economically efficient signals are sent. Decoupling it is not intended to decouple customer bills from consumption. Unit-based pricing (per therm, per kW, per kWh) is essential for relating customer costs to usage: the more one uses the more one pays, and conversely. Customers continue to see the cost implications of their consumption decisions. A flat, non-volumetric monthly price per customer would be a form of decoupling – revenues would not be a function of sales – but it would come with other ills too great to justify it: inequity (low-volume users subsidize high-volume users) and an under-valuing of resources (it creates the notion that incremental usage is cost-free and thus would spur uneconomic demand). It is precisely to preserve usage-based pricing, while simultaneously resolving the throughput problem of traditional regulation, that decoupling was devised.

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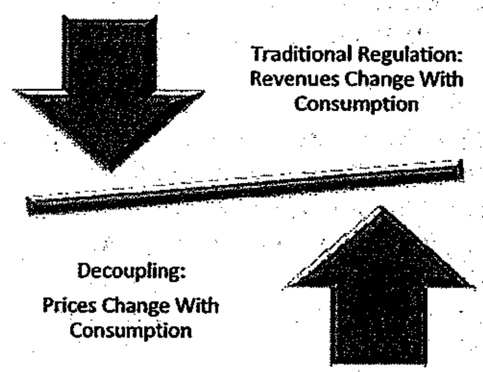
[21] National Association of Regulatory Utility Commissioners, "Resolution in Support of Incentives for Electric Utility Least-Cost Planning," adopted July 27, 1989.

[22] This is not to say that other factors, such as interest rates, commodity prices, and the state of the economy do not affect costs. They do. But we are merely stating the obvious – that it is the existence of the demand itself that causes the costs.

C. Essential Mechanics of Decoupling

Traditional Regulation vs. Decoupling



Decoupling is accomplished through a simple change in regulation. Under traditional regulation, prices for the non-commodity portion of the utility's cost of service are set at the end of each rate case and remain in effect until the next rate case.[23] As a result, utility revenues and customer bills will rise or fall with changes in unit sales. With decoupling, revenues are held to a specified level and prices are allowed to change as necessary to collect that amount.

1. Revenue-Cap Decoupling

The simplest form of decoupling, often called "revenue-cap decoupling" allows the utility to collect the exact revenue requirement determined in the last rate case. This is done by holding the annual Revenue Requirement constant between rate cases. In any period after the rate case, prices are recalculated by dividing the actual units of consumption into the Allowed Revenue, set in the last rate case. Table 3 demonstrates the mathematics of the calculation. The initial price comes from the last rate case and is derived by dividing the revenue requirement by the test year weather-normalized unit sales. In the example, the result is a price of $.10 per Unit of Sales. To this point, both traditional regulation and decoupling are identical in approach, but this is where they diverge. Whereas this price is *the* price under traditional regulation, it is actually of little importance under decoupling.

Table 3
Periodic Decoupling Calculation

From the Rate Case	
Allowed Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10/Unit
Post Rate Case Calculation	
Actual Unit Sales	99,000,000
Allowed Revenues (from above)	$10,000,000
Required Total Price	$0.10101/Unit
Decoupling Price "Adjustment"	$0.00101/Unit

In any period after the rate case, actual sales will almost certainly be different than the test year sales. Decoupling automatically accounts for this deviation by recalculating the price – Price is equal to the Allowed Revenue divided by *Actual* Unit Sales. In the example, sales are assumed to have declined by 1 million units and the resulting price is

[23] The entirety of the calculations and methodologies discussed here relate solely to the non-commodity portion of the utility's cost of service and of the customers' bills.

$.10101 per Unit of Sales, or $0.00101 higher than the price originally set in the rate case.

2. Revenue-per-Customer Decoupling

As a practical matter, between rate cases most of the utility's non-commodity costs do not change and can be considered fixed.[24] However, some costs, mostly related to distribution system expansions plus metering and billing to serve new customers, do change with the number of customers being served. Revenue-Cap Decoupling can be modified to reflect this, using a form of decoupling referred to as Revenue-per-Customer ("RPC") Decoupling.

RPC Decoupling begins with a traditional rate case and prices are set in the usual manner, using traditional rate design techniques. Based on the adjusted test year values in the rate case, average revenue-per-customer values for each rate class can be easily computed. This calculation uses the same values used to compute the prices set in the rate case. For each rate class, RPC values are calculated for each volumetric rate and for each billing period.[25] While this calculation is not usually done in a traditional rate case, it is easily derived from data found in the rate case. The average revenue per customer is separately derived for each month, for each rate class and for each applicable volumetric rate ($/kWh and $/kW, or $/therm) for each rate class. With the RPC calculations in hand, the allowed revenues for any post-rate case billing period can be calculated by multiplying the RPC value by the actual number of customers, resulting in the RPC allowed revenue. Table 4 demonstrates the adjustment which is made to the allowed revenue. The addition of 500 customers increases the allowed revenue by $25,000.

Table 4
Periodic Decoupling Calculation

From the Rate Case	
Allowed Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10/Unit
Number of Customers	200,000
Revenue Per Customer (RPC)	$50.00
Post Rate Case Calculation	
Number of Customers	200,500
Allowed Revenues (=$50 * 200,500)	10,025,000
Actual Unit Sales	99,225,000[26]
Required Total Price	$0.101033/Unit
Decoupling Price "Adjustment"	$0.001033/Unit

[24] From an accounting perspective, the only utility costs actually deemed "fixed" are depreciation and interest expense. When under financial stress, utilities can reduce costs that otherwise appear unvarying in the short run. For example, they can (and do) defer maintenance, defer capital programs, suspend line-clearing activities, change billing frequency, and even omit dividends and lay off employees when circumstances warrant.

[25] While we often think of utility bills as being rendered on a monthly basis, utilities actually render bills on a billing cycle basis, which spreads the meter reading and printing of bills over the entire month. There are usually 20-22 billing cycles in a month (one for each non-weekend day).

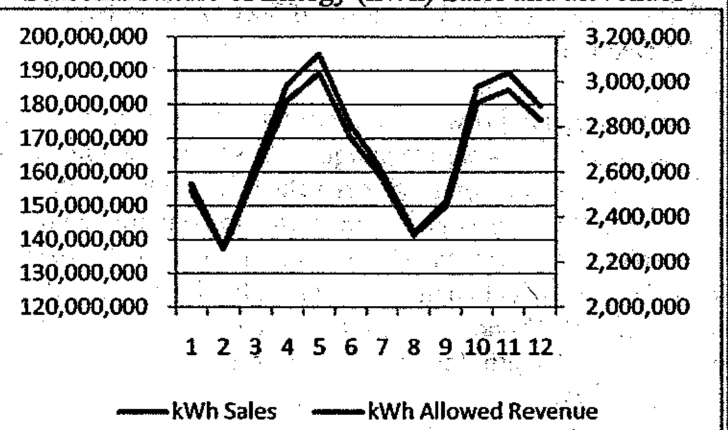
[26] Here we have assumed that new customers use, on average, 450 units each, rather than the "old" customer average of 500 units.

From this point, the recalculation of prices is accomplished in the same manner as with revenue-cap decoupling. The RPC allowed revenues are divided by the actual unit sales, to derive the new price – in the example, $0.101033/Unit.

3. Application of Decoupling – Determination of Allowed Revenues

Both revenue-cap decoupling and RPC decoupling adjustments are applied to the volumetric prices of each rate class. Table 5 reflects the seasonal nature of consumption and revenues using actual data from PPL, an electric utility in Pennsylvania.[27]

Table 5
Seasonal Nature of Energy (kWh) Sales and Revenues



Using consumption based on billing cycle data, allowed revenue values are calculated for each period. In this example, the kWh allowed revenues are shown. For rate classes with demand charges, comparable data would be used to calculate kW allowed revenues. Under revenue-cap decoupling, the allowed revenue for each billing cycle would remain essentially constant between rate cases. Under RPC decoupling, a separate revenue per customer value is calculated for each volumetric price and is then used to adjusted the allowed revenue in each post-rate case period. The calculation should be performed on a billing cycle basis because the underlying data in the rate case are based on billing cycle data.

4. Application of decoupling – Current vs. Accrual Methods

Under traditional regulation, utilities have often had different adjustment factors on customer bills. Perhaps the most common is the fuel and purchased power adjustment clause for electric utilities and the gas purchase adjustment clause for gas utilities. In both of these cases, utilities compute the actual costs for these items and then customer bills are adjusted to reflect changes in those costs. There is often a lag in the determination of these costs and the adjustment factor itself is often based on the forecast units of sales expected in the period when adjustment will be collected. As a result, actual collections usually deviate from expected collections and a periodic reconciliation must be made to adjust revenues accordingly.

In the application of decoupling, many states use a similar approach or make the calculations on an annual basis. Any accrued charges or credits are held in a deferral

[27] In this case, the Test Period began on October 1 (month 1) and ran to September 30 (month 12). Here the data was provided on a monthly basis, rather than on a billing cycle basis.

account for subsequent application to customers' bills. When applied in this manner, the same reconciliation routines are used to assure collection of the amounts in the accrual account.

When a lag is present in the application of these adjustments, it has the effect of disassociating individual customers from their respective responsibility for the adjustment. The result is a shift in revenue responsibility among those customers, and between years. For example, if a warmer-than-average winter produces a significant deferral of costs to be collected, and it is collected the following year, it is possible that the surcharge will be effective during a colder-than-average winter, exacerbating customer bill volatility.

Unlike commodity adjustment clauses, however, there are no forecasting components involved in decoupling. This is true even for utilities whose rate cases use a future test year. While future test years necessarily involve forecasting the revenue requirement, the calculation of the actual price to be charged to collect that revenue requirement is a function of actual units of consumption. In order to calculate the price with Revenue Cap Decoupling, one need only divide the Allowed Revenue by the Actual Unit Sales. In order to calculate the price with RPC Decoupling, one must first derive the Allowed Revenues (based on the current number of customers) and then divide that number by Actual Unit Sales. In either case, *all* of the information needed to make the calculation is known at the time customer bills are prepared. For this reason, the required decoupling price adjustment can be applied on a current, rather than an accrued, basis. This also means that there will be no error in collection associated with forecasts of consumption and, hence, no need for a reconciliation process.

This can be done by using the same temperature adjustment data used to produce the test year normalized results, except to calculate a daily or monthly RPC with the data, not just an annual RPC. In each billing cycle, the "allowed" RPC can be a time-weighted average of the number of days in each month of the year included in the billing cycle. For example, if the allowed RPC is $50 for March and $40 for April, and the billing cycle runs from April 16 to March 15 (i.e., 15 days in April and 15 days in March), the allowed RPC would be $45.

5. Application of RPC Decoupling: New v. Existing Customers

Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small cross-subsidies. As illustrated in Table 6, if new customers, on average, use 450 kWh in a billing period but the rate case derived RPC for existing customers was 500 kWh, application of the test year RPC values to new customers has the effect of causing old customers to bear the revenue burden associated with the 50 kWh not needed nor used by new customers. This is because the allowed revenue is increased by an amount associated with 500 kWh of consumption, while the actual contribution to revenues from the new customers is only the amount associated with 450 kWh.

Table 6			
	Existing Customers	New Customers	Total
Number of customers	200,000	500	200,500
RPC Value	$50.00	$50.00	
Allowed Revenues	$10,000,000	$25,000	$10,025,000
Average Unit Sales	500	450	
Decoupled Price (from Table 4)	$0.101033	$0.101033	$0.101033
Collected Revenues	$10,002,267	$22,733	$10,025,000
Per-Customer Contribution	$50.5165	$45.46	$50.00

To correct for this, a separate RPC value can be calculated for new customers – in our example, the amount would be $45.00 for new customers. As shown in Table 7, the RPC allowed revenues would be not increased from $10,000,000 to $10,025,000. Instead, the increase would be equal to only $22,500.

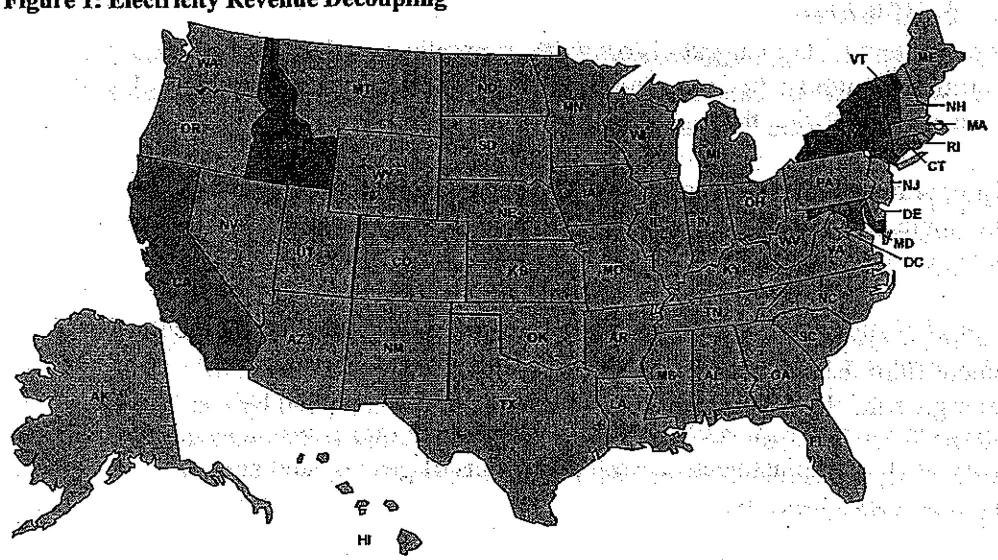
This results in collection of an average of $50.00 from existing customers and $45.00 from new customers, thus reflecting the overall lower usage of new customers. On a total basis, the average revenues per customer are equal to $49.99.

Table 7			
	Existing Customers	New Customers	Total
Number of customers	200,000	500	200,500
RPC Value	$50.00	$45.00	
Allowed Revenues	$10,000,000	$22,500	$10,022,500
Average Unit Sales	500	450	
Decoupled Price ($10,022,500 ÷ 99,225,000)	$0.1010101	$0.1010101	$0.1010101
Collected Revenues	$10,00,000	$22,500	$10,022,500
Per Customer Contribution	$50.00	$45.00	$49.99

D. Current Experience with Gas and Electric Decoupling

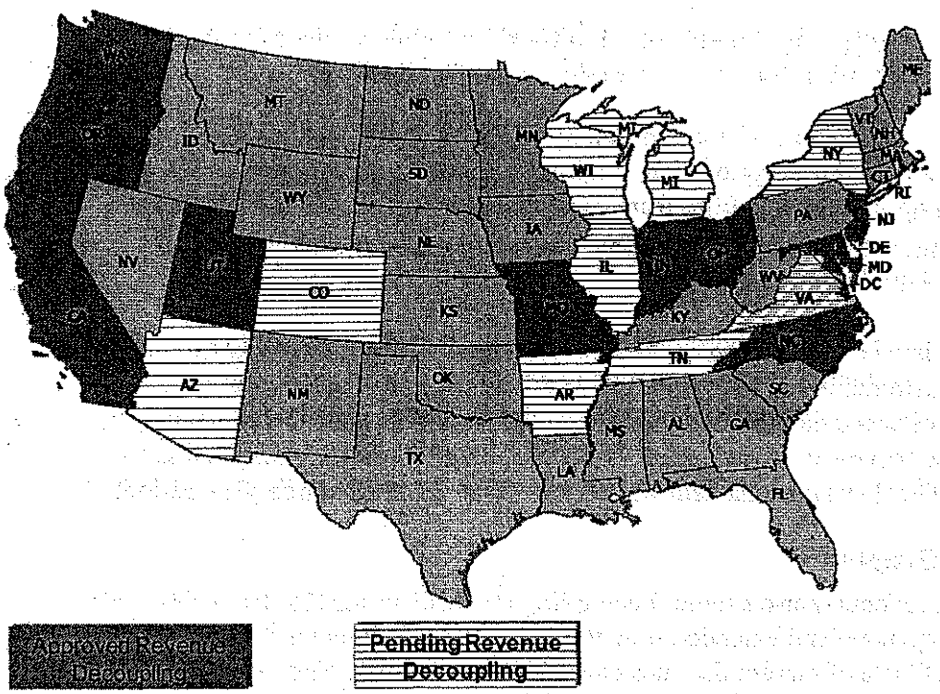
Figures 1 and 2 summarize the current status of electric and gas decoupling in the United States. In the subsections that follow, activities in selected states are described in more detail.

Figure 1: Electricity Revenue Decoupling[28]



LEGEND
States where all electric IOUs are decoupled, or must be decoupled in near future (CA, CT)
States where at least one electric IOU is decoupled (ID, MD, NY, VT)
States considering decoupling (docket or investigation opened, or utility has filed proposal) (CO, DC, DE, HI, KS, MA, MN, NH, NM, WI)
States where commission has indicated it will consider decoupling proposals (AR, IA)

Figure 2: Natural Gas Revenue Decoupling[29]



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[28] Regulatory Assistance Project, April 2008

[29] American Gas Association, presentation to NARUC, 17 July 2007.

1. California

California is the state with the longest history with decoupling. It has been in place for natural gas utilities for almost 30 years, and for electric utilities for the same period, with a multi-year suspension during the restructuring era.

California decoupling is only one small part of a complex regulatory framework in California that includes as many as seventeen different adjustment mechanisms that operate between general rate cases.

California's decoupling system is a simple revenue cap, with the allowed distribution revenue requirement from the general rate case trued up without consideration of inflation, customer growth, or other factors. However, this is accompanied by use of a future test period in the rate case, an "attrition" case between rate cases that captures inflation and productivity adjustments as well as impacts of growth, and annual adjustment of the return on equity.

2. Washington

Washington experimented with electric decoupling beginning in 1990, with a mechanism for Puget Sound Power and Light Company (now Puget Sound Energy). The Puget mechanism divided costs into "base costs" which were adjusted annually on a revenue per customer basis, and "resource costs" which were adjusted annually to reflect changes in actual power supply costs, both fixed and variable. The mechanism was terminated after four years, primarily due to the rising level of resource costs.

Washington has recently approved partial and limited decoupling mechanisms for Cascade Natural Gas Company and Avista Utilities natural gas service.

The Cascade mechanism was adopted in January, 2007, and recalculates revenues based on normal weather conditions prior to determining if a decoupling adjustment is required. Because it does not protect the utility from earnings volatility caused by variations in weather, the Commission chose not to impose a cost of capital adjustment. It was approved for an initial three-year period.

The Avista mechanism is even more limited. Not only are sales restated to reflect normal weather, but new customer usage is completely excluded from the decoupling mechanism. This reflects evidence that much of the decline in usage per customer is caused by lower use by new customers, and that is accounted for in the utility's line extension policy. The Avista mechanism was approved for an initial three-year period.

3. Oregon

Oregon approved a revenue-per-customer decoupling mechanism for Northwest Natural Gas in 2002, and expanded and extended it in 2005. Initially, the mechanism only allowed recovery of 90% of margin declines caused by lower sales. The Commission required a formal evaluation of the NWNG mechanism, prepared by Christensen Associates, which concluded, among other things, that decoupling was a primary contributor to a bond rating upgrade for NWNG. As a result of the 2005 review process, the NWNG mechanism was modified to provide for 100% recovery of margin declines, and extended to 2009.

In 2006, the Oregon PUC approved a settlement with Cascade Natural Gas implementing a full revenue-per-customer decoupling mechanism. It does not make use of a "K" factor nor does it provide for separate treatment of new customers.[30] While the Commission did not order a cost of capital adjustment, Cascade agreed to donate 0.75% of revenues, from shareholder funds, to the Energy Trust of Oregon for energy efficiency programs; this is approximately equal to the effect of a 2% reduction in the equity capitalization rate. An additional 0.75% of revenues from an energy efficiency surcharge is also transmitted to the ETO.

4. Idaho

The Idaho PUC approved a two-part decoupling mechanism in 2007 for Idaho Power Company. The first part is a fixed cost per customer for delivery services. The second part is a fixed cost per unit of energy, attributable to power supply. This is a limited decoupling mechanism, with sales adjusted to reflect normal weather prior to calculation of the decoupling adjustment. Any surcharge or surcredit is reflected on the customer bill as part of the energy conservation program charge. Rate increases of more than 3% are not allowed (but, with weather restated to normal, it is pragmatically unlikely that any adjustment would reach this magnitude).

5. Utah

In 2006, the Utah Public Service Commission approved a three-year pilot full decoupling mechanism for Questar Natural Gas Company, without a K factor or separate treatment of new customers. The Commission did not order a cost of capital adjustment, but did require that Questar begin the deferral accounting (for the decoupling adjustments, both up and down) with a $1.1 million credit in the customer's favor.

6. Maryland

Baltimore Gas & Electric Company (BGE) currently operates under a full decoupling program for its residential and general service gas customers. It is a simple revenue-per-customer (RPC) mechanism, based on a rate case test-year revenue requirement. The RPC is expressed as a function of average usage per customer per month. Revenue adjustments are made monthly, and any difference between actual and average use per month is reconciled in a future month.

In 2007, the Maryland Public Service Commission approved the decoupling proposal ("Bill Stabilization Adjustment Rider") of the Potomac Electric Power Company (Pepco). Like BGE's, it is a full decoupling, revenue-per-customer program. Adjustments are

[30] A "K" factor can be built into a decoupling mechanism to adjust for other factors that policymakers may deem important, e.g., trends that would have affected the revenues that the utility would have received under traditional regulation. A "K" factor can be linked to expected changes in average use per customer. It doesn't reward or penalize the utility for changes in usage – instead, it is intended to eliminate the risk of a predictable windfall or loss.

made monthly, capped at ten percent, with any excess carried over to a future period.[31] In recognition of the reduced risks that Pepco would face, the Commission lowered the company's otherwise allowed return on equity by 50 basis points. It also approved a similar decoupling proposal for Delmarva Power (which, like Pepco, is a wholly-owned subsidiary of Pepco Holdings, Inc.).

a) MADRI

The Mid-Atlantic Distributed Resources Initiative (MADRI), a cooperative effort of state regulators in New Jersey, Delaware, the District of Columbia, Maryland, and Pennsylvania,[32] developed a generic approach to decoupling, referred to as the Revenue Stability Model Rate Rider. It describes the mechanics of a full revenue-per-customer decoupling regime, and it was based largely on the BGE program. It in turn became the model for the Pepco and Delmarva plans.[33]

7. North Carolina

North Carolina's three major gas utilities were decoupled in November 2005. The Public Utilities Commission based its decision to do so on several findings: one, conservation has the potential to cause financial harm to the utility and its shareholders; two, decoupling offers better opportunities for the conservation of energy resources and savings for customers, thereby putting downward pressure on wholesale gas prices; three, decoupling better aligns the interests of the utility and its customers; and, four, it reduces shareholder risk.

The PUC approved the decoupling mechanism as an experimental tariff – the Customer Utilization Tracker (CUT – and limited it to no more than three years unless reauthorized by the PUC. It is a full revenue-per-customer decoupling mechanism for residential and commercial customer classes, adjusted semi-annually. The Commission excluded industrial customers from the CUT, reasoning that their different usage patterns provided good cause to do so. The PUC required that the utilities make significant contributions toward conservation programs, and rejected the Attorney General's argument that decoupling would penalize customers for conserving. Lastly, the Commission recognized the importance of volumetric rate structures and lower fixed customer charges. It rejected the "straight fixed-variable" rate design proposal, with its higher fixed charges, on the ground that customers' bills should be tied to their usage.

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[31] This is a very high cap and it is not expected to be reached. Adjustments have so far averaged well below one percent.

[32] "The Mid-Atlantic Distributed Resources Initiative (MADRI) seeks to identify and remedy retail barriers to the deployment of distributed generation, demand response and energy efficiency in the Mid-Atlantic region. MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection." http://www.energetics.com/MADRI/.

[33] The Model Rider can be found at http://www.energetics.com/MADRI/regulatory_models.html. The revenue-per-customer approach to decoupling was first developed by RAP principals in the early 1990s.

8. New Jersey

New Jersey Natural Gas Company and South Jersey Gas Company proposed full revenue-per-customer decoupling mechanisms in 2005. The mechanisms would have covered the revenue impacts resulting from sales deviations due to normal weather, energy efficiency, and other factors (e.g., economy). The difference between actual revenues and allowed revenues (the product of number of customers, average usage/customer, and price) would be recovered (or credited) through the new Conservation and Usage Adjustment (CUA) clause in the following year.

The cases were settled in 2006. Limited revenue-per-customer decoupling for non-weather-related sales changes only was approved. It is called the Conservation Incentive Program (CIP), and is being run as a three-year pilot. Revenue adjustments cannot exceed the amount by which the company reduces total costs of Basic Gas Supply Service (i.e., the commodity savings that result from company investments in energy efficiency). Revenue shortfalls that are in excess of the gas supply savings can be recovered in later periods, to the extent that there is room under the cap to do so. Company-sponsored energy efficiency programs were greatly expanded, but, in an interesting twist, the settlement called for the costs of efficiency programs to taken "below the line" (i.e., not included in the regulated cost of service, but rather paid for out of company earnings. This had the effect of reducing the companies' returns on equity, in recognition of the reduced risk that they would now face.

9. Vermont

At the end of 2006, the Vermont Public Service Board approved a modified revenue cap (partial decoupling) for Green Mountain Power Corporation (GMP), a vertically integrated electric company. GMP's allowed base revenues (non-power costs) will be pre-determined for each of the three years of the program, in accordance with the terms of a memorandum of understanding signed by the utility and several parties. Changes in base revenues are capped at $1.25 million for 2008 and $1.5 million for 2009, although the caps can be exceeded, if necessary, for specified exogenous costs. The company's earnings are bounded by sharing collars: the first 75 basis points, up or down, are borne by GMP; the next 50 basis points are shared half-and-half between the company and its customers; and anything after that is borne by the customers. The company's power costs are subject to a quarterly fuel adjustment clause. Variances in costs of committed resources (owned units or contractual entitlements) are borne entirely by the customers. Variances up to $400,000 per quarter for non-committed (i.e., market) resources are covered by the company. Variances in excess of the $400,000 are covered by customers. However, if the total variance would result in an adjustment of greater than $0.01/kWh, the excess will be carried over to a following quarter.

E. Cost-of-Capital Impacts of a Lower Equity Ratio

The cost of capital is a function of the cost of common equity, the cost of debt, the proportion of each used to finance the utility, and the tax rates to which each are subject. While equity is subject to income tax, interest on debt is deductible for income tax purposes. Therefore equity in a utility capital structure is much more expensive to consumers than debt.

Under decoupling, utility financial risk is reduced, since earnings no longer vary with weather or other causes of sales variation. Because earnings are more stable, utilities can have a more leveraged capital structure, and still retain the equivalent bond rating.

The calculation below, which includes tax effects on both debt and equity, shows how a 3% reduction in the equity capitalization ratio produces about a 3% reduction in the return and taxes needed to support the utility rate base.

Cost of Capital Impacts			
Without Decoupling	Ratio	Cost	Weighted With-Tax Cost of Capital
Equity	45%	11.0%	7.62%
Debt	55%	8.0%	2.86%
Weighted Cost			10.48%
Revenue Requirement: $1 Billion Rate Base			$ 104,800,000
With Decoupling			
Equity	42%	11.0%	7.11%
Debt	58%	8.0%	3.02%
Weighted Cost			10.13%
Revenue Requirement: $1 Billion Rate Base			$ 101,280,000
Savings Due to Decoupling Cost of Capital Benefit:			$ 3,520,000

F. Elasticity Impacts of Straight Fixed/Variable Pricing

The table below shows how straight fixed/variable pricing affects the amount of natural gas a utility would be expected to sell.

The basic assumptions for the sales volumes and costs are quite simple; the utility has 100,000 customers, and an annual revenue requirement of $130 million.

Under SFV pricing, the rate design would be $30 per month plus $1.00 per therm, while with volumetric pricing, the rate design would be a flat $1.30/therm for all gas used.

Volumetric pricing would increase the customer's rate per therm by 30%.

Based on an assumed long-run arc elasticity (elasticity over a significant change in price) of 0.50, a conversion from SFV to volumetric pricing would be expected to produce an 18% reduction in total gas sales.

Estimates of elasticity for natural gas are measured on both a short-run and long-run basis. In the short-run, elasticity is typically very low, on the order of -0.05 to -0.15, while in the long run (when customers can buy new appliances, insulate homes, and convert fuel sources) the elasticity is much higher, in the range of -0.020 to -0.070.

The selection of -0.50 as a long-range arc elasticity for natural gas is for illustrative purposes only, and not intended to be representative of the elasticity of demand for gas on any particular natural gas utility. At least one study supports this assumption.[34]

[34] Price Elasticity of Demand, Mackinac Center for Public Policy, 1997 http://www.mackinac.org/article.aspx?ID=1247

Hypothetical Gas Utility

Customers			100,000
Annual Sales	Therms		100,000,000
Annual Revenue Requirement		$	130,000,000

Rate Design With Straight Fixed Variable Pricing			
Customer Charge	$/month	$	30.00
Annual Customer Charge Revenue		$	36,000,000
Gas Supply Rate	$/therm	$	1.00
Gas Supply Revenue	$/year	$	100,000,000
Total Revenue	$/year	$	136,000,000

Rate Design With Volumetric Pricing			
Therms Sold	Therms/year		100,000,000
Distribution Rate	$/therm	$	0.36
Distribution Revenue	$/Year	$	36,000,000
Gas Supply Rate	$/therm	$	1.00
Gas Supply Revenue	$/year	$	100,000,000
Total Rate	$/Therm	$	1.36
Total Revenue	$/year	$	136,000,000

Therm Savings From Volumetric Pricing			
Unit Price, SFV Pricing		$	1.00
Unit Price, Volumetric Pricing		$	1.36
Change in Price/Therm			36%
Assumed Long-Run Arc Elasticity			-0.50
Estimated Elasticity Response			18%

Bill Impact of SFV Pricing

Usage	Volumetric	SFV	Difference %
10	$ 13.60	$ 40.00	194%
50	$ 68.00	$ 80.00	18%
100	$ 136.00	$ 130.00	-4%
200	$ 272.00	$ 230.00	-15%
300	$ 408.00	$ 330.00	-19%