The Many Factors that Affect the Success of Regulatory Mechanisms Designed to Foster Investments in Energy Efficiency

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Key Questions

- Absent any special incentives, will an electric utility under traditional regulation invest in energy efficiency programs?

- What factors impact the effectiveness of special regulatory mechanisms designed to encourage utilities to pursue conservation?

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Introduction

The National Action Plan for Energy Efficiency prepared by the U.S. Environmental Protection Agency reports that “Few energy efficiency policy issues have generated as much debate as the issue of the impact of energy efficiency programs on utility margins.”

The reduction in profitable sales resulting from energy efficiency poses a disincentive to utility investments in energy efficiency.

Utilities make money by selling energy. Right? Why would a utility want to reduce its energy sales?
If We Have a Policy Goal to Encourage Energy Efficiency through Electric Utilities

- We could force the utilities to do it
- Or provide an economic incentive to encourage a utility to invest in energy efficiency
Bill Clinton explains utility decoupling

Regulatory reform of utilities could lessen the need for new power plants

BY JOSEPH ROMM

A 4 OCT 2007 6:08 PM

Last week, the Clinton Global Initiative (CGI) announced that eight utilities are committed to seeking regulatory reforms and approvals to increase their investment in energy efficiency by $200 million annually to about $1.5 billion annually.

The utilities — Con Edison, Duke Energy, Edison International, Great Plains Energy, Pepco Holdings, PNM Resources, Sierra Pacific Resources, and Xcel Energy — represent nearly 25 million customers. The extra efficiency effort would "reduce carbon dioxide emissions by about 35 million tons" and "avoid the need for 50,500-megawatt peaking power plants."

What regulatory reform? Our former President offered "to try to explain it to you in my basic English," which I reprint here.

Here's the way you pay your electric bill in America, you go — the electric company gets permission to charge a certain rate per kilowatt hour, so the more you use, the more you pay, and this is the way it is everywhere. Only California today has the power to disconnect how much you pay from how much you use [actually, a few states do]. The significant thing is you can pay a little more kilowatt hour and pay over time for investments in energy efficiency. They've been working on this for 32 years. As a result in California, our largest state, the per capita energy consumption is only 50 percent of the national average.

Mr. "Roger" idea is to have all the utilities have the option and eventually the responsibility to tell every homeowner and every business owner in the United States that they have a right not just to electricity but to the most efficient energy publicly available, and this is not a user-friendly practice. I think I said something about this yesterday. It's not the easiest thing in the world to go out and figure out how to maximize your insurance, and what is the most cost effective thing to do.

If the utilities do this, then they can put together a plan, go find all the contractors, get all the materials and in effect pay for the cost on your home or in your office building if they were building a mini power plant there. That is instead of financing it like a consumer loan for one year or a car loan for three. It could be financed over a twenty-year period or longer. The consumer then would have to pay for a little more per kilowatt hour but so much that they would still have lower total utility bills because they'd be using so much less. So suppose they make your home 30 percent more efficient, they charge you 15 percent more per kilowatt hour, so your bill goes down 15 percent and plus they get the financing they need, collectively it will be much less expensive for them than building a new power plant. They'll be able to finance and we won't be contributing any more to climate change.

This is a simple, brilliant idea, but it has the capacity to fundamentally transform what we have been doing in America... This has a potential to fundamentally change the nature of this debate in a way that will prove its great economic and possible to effectively reduce greenhouse gas emissions...
Conservation Can Mean Profits for Utilities

States are changing the rules of the game so that it pays power companies not to expand.

By MARIANNE LAVELLE
April 17, 2008

High-efficiency furnace sales around Portland, Ore., are hotter than anywhere in the nation. And the state credits the region's gas utility, NW Natural, with persuading customers to pay the $2,700 premium (softened by about $600 in rebates and tax incentives) for high-end units instead of letting inefficiency send 20 percent of their heating dollars up the flue.

A utility urging customers to use less energy? Seems impossible, since more BTUs and more kilowatts always meant higher profits in the energy business. But states are changing the way that utilities get paid—decoupling profits from energy consumption—to promote efficiency and curtail the need for new power plants. Both Hillary Clinton's and Barack Obama's campaigns tout the concept. Last year, Connecticut, Idaho, New York, and Vermont chose decoupling, and a dozen other states now are considering jumping on the bandwagon. "It's an idea whose time has come," says Roger Cooper of the American Gas Association, which represents gas utilities. Some states even want to supercharge decoupling, offering rewards to, in the words of Ralph Cavanagh, senior attorney for the Natural Resources Defense Council, "make utilities motivated partners in energy efficiency."

Power to the people. Historically, they've been quite the opposite. "Our entire utility system was constructed around the objective to expand the system to bring power to more people," says Marty Kusler, director of utility programs for the American Council for an Energy-Efficient Economy. "The whole structure was set up to encourage more use of electricity and, therefore, more power plants. It was a self-perpetuating growth machine."

When electric utilities build new power plants, they can add the capital investment to the rates they charge customers. Natural gas utilities similarly are rewarded for selling more. Shareholders applaud increased energy use because it increases returns. But NW Natural Chief Executive Mark Dodson said his utility sought a different way after the western energy crisis of 2000-01, when calls for conservation increased. "I'm thinking, 'Does this make any sense going forward in the 21st century, to have shareholders on opposite sides from the customers?' " says Dodson.

State regulators typically determine a fair return for utilities based on their plants, pipelines, and other capital investments. But with decoupling, states reassess each year.

1. Whispers: Obama Labor Boss Buys Canadian-Built Car
Regulatory Mechanisms

- **Lost Revenue Adjustment Mechanisms (LRAMs)** compensate the utility for the margins or earnings lost as a result of reduced sales. The impacts of energy efficiency programs upon the utility’s sales are estimated. The under-recovery of earnings or margins resulting from energy efficiency programs is then calculated. Adjustments or true-ups are undertaken to compensate the utility for the earnings foregone as a result of its investment in energy efficiency.

- **Decoupling** seeks to fully divorce earnings and revenues from sales, thus removing the “throughput incentive.” Allowed revenue or allowed revenue per customer is calculated. Rates are periodically adjusted through true-ups to ensure that the utility receives its allowed revenues or margins. The revenue collection allowed by the regulatory authority may be either increased or decreased under decoupling. As a result, actual utility revenues track projected revenue requirements despite unexpected fluctuations in sales.
States with Electric Decoupling Plans

- Current Plans
- Expired Plans
States with LRAM Plans
Demand Side Management (DSM)

My Approach

- Determine the utility’s optimal profit-maximizing level of DSM and the mix of DSM programs selected by the utility under various ratemaking schemes.

- The focus here is to explore a utility’s motivation to pursue energy efficiency investments under various market conditions and regulatory incentive mechanisms.

- I modeled a hypothetical electric utility using a non-linear optimization model.
My Hypothetical Electric Utility

- Buys fuel (e.g., natural gas, uranium, coal)
- Converts the fuel into electricity
- Transmits the electricity to consumers
- Sell power to consumers at a retail level
- Can make investments in DSM, including energy efficiency
- Three types of DSM are available to the electric utility: load management (the utility can turn off appliances or equipment at the consumer’s site), medium DSM (perhaps, energy efficiency programs providing a rebate to promote high efficiency air conditioners), and base load DSM (e.g., promotion of energy efficient refrigerators or water heaters).
What Happens Under Traditional Regulation

Under traditional regulation with annual rate adjustments, a utility with no regulatory mandate to pursue DSM will weigh certain benefits against certain costs in deciding whether to invest in DSM.

The utility sees a benefit if it can avoid uneconomical sales – e.g., peak period sales of electricity for which the cost of making the sale exceeds the retail price at which the electricity may be sold.

This savings in operating cost increases the utility’s profit, provided prices are based on the utility’s cost of service in a previous year (an historical test-year).

This may be negated through automatic pass-through mechanisms and true-ups.

The efficiency gain through DSM focused on reducing uneconomical sales has a secondary effect – the resulting reduction in future retail prices may lead to higher future sales, revenues, and profits through the price elasticity of demand effect.
What Happens Under Traditional Regulation, continued

Under traditional regulation, there may be a detrimental financial impact on the utility if the DSM reduces the utility’s future rate base and thus the future financial returns to the utility permitted by the regulatory authority.

A one-time payment by the utility to foster consumer investments in energy efficient equipment may impact demand on the utility’s system, the utility’s load shape, operating costs, and the utility’s capacity needs over the life of the equipment promoted through a DSM program.

Further complicating the analysis, there is considerable feedback among key variables. DSM investments affect retail prices, operating costs, and capital costs. The level and type of DSM investment, retail prices, operating costs, and capital costs should be treated endogenously.
What Happens Under Decoupling

The utility’s incentive to achieve efficiencies by reducing uneconomical sales is greatly weakened. The reconciliation process prevents the utility from keeping the profits resulting from efficiency gains.

The utility has an incentive to invest in the types of DSM which will reduce the utility’s sales. The utility has a financial incentive to increase the rate adjustment to its revenue requirement since a higher adjustment to rates will lead to higher revenues and profits. (This point is controversial.)

As is the case under traditional regulation, price elasticity effects and the impact of DSM on opportunities to receive future returns on investments in new capacity which will expand its rate base complicate the story.

The utility’s interest in earning returns from an increasing rate base may remain strong, but factors such as the cost of capital and avoided costs will determine the strength of this motive.

These factors suggest that the type of DSM favored by a utility under decoupling will be quite different from the type of DSM pursued by a utility under traditional regulation.
What Happens with a Lost Revenue Adjustment Mechanism (LRAM)

The LRAM is calculated as the revenue loss associated with DSM (i.e., the MWh sales lost as a result of DSM multiplied by the retail price) minus the operating costs which are avoided as a result of the foregone sales.

This difference is divided by sales which are adjusted for the impact of DSM.

Using this factor, the retail price is raised to compensate the utility for any revenue loss resulting from DSM investments.

The prospect of this additional charge on retail bills seeks to ensure that the utility’s profits are no lower than under traditional regulation.

A properly designed LRAM removes traditional regulation’s disincentive for the utility to reduce profitable types of retail sales (e.g., base load or off-peak sales).

The remaining factors (e.g., price elasticity effects and the ability to earn returns from future rate base additions) determine whether an LRAM can induce any DSM absent an external goal for energy efficiency.

The utility’s incentive to reduce uneconomical retail sales (e.g., sales during peak periods) may be muted.
Yikes! How am I going to model all this?

The typical regulated utility selects an optimal level and mix of DSM programs so as to maximize the present value of profits over T years subject to a demand constraint, requiring it to meet the energy needs of its ratepayers.

A nonlinear optimization model was developed using GAMS (General Algebraic Modeling Software) to examine the impacts of various regulatory incentive mechanisms upon utility earnings and rates under various scenarios.
Regulatory Systems Modeled

1. Traditional ratemaking with an annual adjustment of prices
2. Traditional ratemaking with rate cases every five years
3. Decoupling of margins or revenues from sales volumes with an annual adjustment of prices
4. Traditional ratemaking is adjusted using an LRAM and new rates are set every year
5. Traditional ratemaking is adjusted using an LRAM and new rates are set every five years
Model Structure

Maximize utility profits (discounted profits over a ten-year time horizon)

Subject to:

• DSM programs and price changes (price elasticity of demand) affect the “baseline” demand
• DSM costs (for types of DSM other than load management) exhibit increasing costs as more DSM reduction is achieved
• Load Management DSM costs are assumed to be proportional to amount achieved
• Load Management impacts can’t exceed a certain level
• The utility’s future Rate Base (assets upon which a return may be earned) is reduced by the amount of the DSM impacts that occur at the time of the utility’s peak demand, times the avoided cost of capacity
• Variable operating costs are highest for peak periods ($1000 per MWh) and lower for periods of medium demand ($40 per MWh) and base load demand ($30 per MWh)

• Annual utility expenses are the sum of variable operating costs, depreciation on rate base, debt costs for rate base, and DSM program costs.
• Retail prices equal return on rate base plus expenses divided by “test year” sales
• Revenue to the utility equals price times the quantity of electricity sold
• Profit equals revenues minus expenses

Solve for optimal levels of the following variables:

• annual profits
• annual revenues
• annual operating cost
• DSM demand reduction (for three types of DSM programs)
• DSM cost (in year 1)
• future rate base
• annual expenses
• annual adjusted demand
• annual prices
Modeling Notes

The model is dynamic, in that DSM investment decisions in year 1 affect all the variables over the next ten years.

The model is non-linear. DSM costs are an increasing function of the amount of DSM investment.

Interactions among all the variables, through price elasticity effects and other relationships.
Traditional Regulation with Regulatory Lag

Under traditional regulation, I can assume:

- Prices change every year with prices based on costs incurred by the utility in the previous year, or
- Prices change every five years.

Note that a utility’s profits will generally benefit from regulatory lag if there is load growth and low inflation. Profits may suffer if there is a decline in demand or high inflation.
How I Modeled Decoupling

The expected margin or profit to be earned on each customer is calculated based on test-year costs and test-year levels of sales.

The utility’s recovery of this level of profit for a set of customers is ensured, regardless of any incremental impact of DSM on the current year’s level of sales.

Prices are adjusted each year.

Any under- or over-recovery of margins in one year that is attributable to deviations of actual sales from the level of sales upon which rates are set is reconciled through an adjustment in rates the following year.
How I Modeled LRAM

Lost revenues are calculated and added to the utility’s revenue requirement.

Rates may be adjusted each year or every five years.

A full rate case is not necessary in order to enable the utility to recover these costs.
Load management looks attractive to the utility under traditional regulation with regulatory lag. Base load or medium energy efficiency would be favored by the utility under decoupling or an LRAM.

In this case, 3% load growth is assumed. The utility would likely oppose any decoupling scheme.
Prices under five ratemaking approaches

Prices are lowest under traditional regulation.
Avoided Capacity Costs Set to $0/MW

In the Base Case, I assumed that the capacity costs which could possibly be avoided through DSM where $100,000 per MW. Now I’ll assume $0.

Now there is a little more interest in load management (although the benefit and cost analysis typically applied to this problem would suggest otherwise).
Avoided capacity costs were doubled from the base case assumption.

There is a mild “Aversch-Johnson effect. The utility may be reluctant to pursue DSM investments that may reduce future returns on rate base.
Changes in Avoided Capacity Costs

Relationship between avoided cost ($/MW) and total DSM investment (annual MWh)
External DSM Goal

As a variation from the Base Case Scenario, we consider a situation where a regulatory or governmental authority has set a minimum goal for DSM.

This has become a common practice in U.S. states and in nations which seek to meet targets for reductions in greenhouse gases.

This becomes an additional constraint to the model.

Table 7. External DSM Goal Placed Upon Utility

<table>
<thead>
<tr>
<th>Ratemaking Scheme</th>
<th>Frequency of Rate Changes</th>
<th>Goal?</th>
<th>DSM Investment (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Base load</td>
</tr>
<tr>
<td>Traditional</td>
<td>Annual</td>
<td>No Goal</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>972</td>
</tr>
<tr>
<td>Traditional</td>
<td>Every 5 years</td>
<td>No Goal</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>940</td>
</tr>
<tr>
<td>Decoupling</td>
<td>Annual</td>
<td>No Goal</td>
<td>999</td>
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<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>999</td>
</tr>
<tr>
<td>LRAM</td>
<td>Annual</td>
<td>No Goal</td>
<td>786</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>1000</td>
</tr>
<tr>
<td>LRAM</td>
<td>Every 5 years</td>
<td>No Goal</td>
<td>576</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>1000</td>
</tr>
</tbody>
</table>
Variations in Load Growth

Utility profits are significantly reduced under traditional regulation if there is no natural load growth.

The utility fails to realize a benefit from the regulatory lag inherent in traditional ratemaking if there is no load growth.

<table>
<thead>
<tr>
<th>Ratemaking Scheme</th>
<th>Frequency of Rate Changes</th>
<th>Goal?</th>
<th>3% Growth</th>
<th>No Growth</th>
</tr>
</thead>
<tbody>
<tr>
<td>Traditional</td>
<td>Annual</td>
<td>No</td>
<td>$3.67</td>
<td>$3.19</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>$3.56</td>
<td>$3.06</td>
</tr>
<tr>
<td>Traditional</td>
<td>Every 5 years</td>
<td>No</td>
<td>$3.87</td>
<td>$3.40</td>
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<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>$3.67</td>
<td>$3.16</td>
</tr>
<tr>
<td>Decoupling</td>
<td>Annual</td>
<td>No</td>
<td>$2.94</td>
<td>$3.22</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>$2.94</td>
<td>$3.22</td>
</tr>
<tr>
<td>LRAM</td>
<td>Annual</td>
<td>No</td>
<td>$4.01</td>
<td>$3.50</td>
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<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>$4.05</td>
<td>$3.54</td>
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<tr>
<td>LRAM</td>
<td>Every 5 years</td>
<td>No</td>
<td>$3.91</td>
<td>$3.73</td>
</tr>
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<td></td>
<td></td>
<td>Goal</td>
<td>$3.74</td>
<td>$3.17</td>
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</tbody>
</table>
Variations in Load Growth

When 10% annual decreases in sales are assumed, decoupling becomes favored over traditional regulation, as is evident from Table 9.

Table 9. Utility Profits Under 3% Growth Versus 10% Annual Negative Growth

<table>
<thead>
<tr>
<th>Ratemaking Scheme</th>
<th>Frequency of Rate Changes</th>
<th>Goal?</th>
<th>Utility Profit ($ Millions in present value over 10 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>3% Growth</td>
</tr>
<tr>
<td>Traditional</td>
<td>Annual</td>
<td>No Goal</td>
<td>$3.67</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>$3.56</td>
</tr>
<tr>
<td>Traditional</td>
<td>Every 5 years</td>
<td>No Goal</td>
<td>$3.87</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>$3.67</td>
</tr>
<tr>
<td>Decoupling</td>
<td>Annual</td>
<td>No Goal</td>
<td>$2.94</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Goal</td>
<td>$2.94</td>
</tr>
</tbody>
</table>
DSM Investments Under Higher Price Elasticity of Demand

Table 10. Variation in Price Elasticity of Demand (and no external DSM goals)

<table>
<thead>
<tr>
<th>Ratemaking Scheme</th>
<th>Frequency of Rate Changes</th>
<th>Price Elasticity of Demand</th>
<th>DSM Investment (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Base load</td>
</tr>
<tr>
<td>Traditional</td>
<td>Annual</td>
<td>-0.2</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-0.3</td>
<td>0</td>
</tr>
<tr>
<td>Traditional</td>
<td>Every 5 years</td>
<td>-0.2</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-0.3</td>
<td>0</td>
</tr>
<tr>
<td>Decoupling</td>
<td>Annual</td>
<td>-0.2</td>
<td>999</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-0.3</td>
<td>1071</td>
</tr>
<tr>
<td>LRAM</td>
<td>Annual</td>
<td>-0.2</td>
<td>786</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-0.3</td>
<td>765</td>
</tr>
<tr>
<td>LRAM</td>
<td>Every 5 years</td>
<td>-0.2</td>
<td>576</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-0.3</td>
<td>558</td>
</tr>
</tbody>
</table>

As price elasticity of demand increases (in absolute value), more energy efficiency under decoupling, less under LRAM, and more load management under traditional regulation with no lag.
## Decoupling’s Effects under Further Changes in Assumptions

Table 11. Results for Decoupling Under Alternative Assumptions

<table>
<thead>
<tr>
<th>Scenario</th>
<th>DSM Investment (MWh)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Baseload DSM</td>
<td>Medium DSM</td>
<td>Load Management</td>
<td></td>
</tr>
<tr>
<td>Base Case</td>
<td>999</td>
<td>1008</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>500% Increase in Cost of Baseload and Medium Load DSM</td>
<td>591</td>
<td>600</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>75% Decrease in Cost of Load Management</td>
<td>1001</td>
<td>1010</td>
<td>43.8</td>
<td></td>
</tr>
<tr>
<td>10-Fold Increase in Cost of All Types of DSM</td>
<td>1616</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>
Now, let’s assume a 10% annual growth in rate base, rather than the 3% I assumed in the base case. Regulatory lag hurts utility profits, since costs increase but prices are not adjusted upward in a timely manner.
Findings

Regulatory mechanisms designed to promote energy efficiency and economic conditions affect not only the level of a utility’s DSM investment but also the *types* of DSM programs preferred by the utility.

Decoupling will indeed lead the utility to greater investment in energy efficiency (conservation) than traditional regulation over a broad range of alternative assumptions, although the relative costs of different types of DSM programs impact this.

An LRAM mechanism may also lead a utility to conservation investments.

But in only one case (i.e., exceptionally high growth in the utility’s rate base) was the optimal level of DSM investment higher under an LRAM than under decoupling.

Decoupling and LRAMs would promote DSM investments with low load factors (i.e., programs focused on energy conservation throughout the year, rather than peak load reduction). But this can change if load management becomes sufficiently cheap.
More Findings

The type of DSM investments preferred by the utility is sensitive to avoided costs, program costs, and other variables.

Load management is attractive to a utility under traditional regulation and infrequent rate cases.

At a sufficiently high price elasticity of demand, load management becomes attractive under traditional regulation with annual rate changes, as well.

In an environment of strong growth in energy demand, a utility is likely to favor traditional regulation with its built-in regulatory lag. A fast-growing utility may rightfully see decoupling as a threat to its profits and oppose any policy changes in that direction. In an environment of negative growth, a decoupling mechanism is likely to be preferred over traditional regulation by the utility.
Questions?