

# Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism

Steve Fenrick<sup>1</sup>  
January 6, 2011

## Abstract

Breaking the connection between revenues and sales volume is a hot topic in North American regulation. The mechanisms that adjust revenue are central to revenue decoupling. This paper examines the historic and current record of revenue adjustment mechanisms within the United States utility industry. Research into appropriate revenue decoupling adjustment mechanism within the context of a rate case in Vermont is discussed.

## 1. Introduction

In traditional rate cases, a regulated utility goes before the state regulatory commission to determine the rates they will charge. Raising rates will increase revenues since public utilities face little to no competition and demand for their product is price inelastic. Rates typically cannot be reset until the next rate case. Between rate cases, the only means the utility has of increasing revenues is by output growth.<sup>2</sup>

A utility is able to increase margins by increasing its sales volume because the marginal revenue of volume outweighs marginal cost. The reasons marginal revenue is larger than marginal cost are due to rate design and the cost elasticity of volume inherent in the technology of the utility sector.

A utility would be neutral to variations in volume if costs tracked revenues. This is not the case. Most of utility base rate costs are fixed, implying that the marginal cost of volume is low relative to total costs. However, revenue increases substantially as volume increases; the net effect of volume growth is increased utility margins.

$$P_{Volume} = MR_{Volume} > MC_{Volume} \rightarrow \text{Higher Profits when volume increases.}$$

Revenue decoupling is an attempt to weaken the link between volumes and earnings. The theory is, by freeing the utility from being held hostage to sales growth, the company will then be more apt to engage in conservation programs or, at least, to not be motivated to work contrary to such programs.

This process requires a revenue adjustment mechanism (RAM) that escalates revenue for the subsequent years after a rate case. Without a RAM, the revenue level will stay constant. A financial problem will be created for the utility where revenue is flat but output growth is likely

---

<sup>1</sup> Mr. Fenrick is the leader of PSE's benchmarking and economic studies practice area. He can be contacted at (608) 268-3549 or via e-mail, fenricks@powersystem.org.

<sup>2</sup> With the exception of items such as power adjustment clauses.

to be positive. In such cases, rates will decline by the rate of output growth. This is especially troubling when confronted with the prospect of inflation where unit costs will be rising but rates will be falling.

Without an appropriate RAM, revenue decoupling will likely cause chronic rate cases or financial distress. Costs associated with rate cases include commission, utility, and other intervener expenses, and utility management and personnel being distracted from the central services of the utility. A compensatory RAM allows the time span between rate cases to lengthen drastically reducing both direct and indirect regulatory cost.

### *Straight Fixed Variable Rate Design*

An alternative method to revenue decoupling is to re-design rates to be cost-causative. As previously stated, rate designs typically result in utilities collecting a majority of revenues from volumetric charges. One method of eliminating the incongruity between volume effects on revenue and cost is re-designing rates to align with the drivers of cost.

Making rates more cost-causative moves the utility towards profit neutrality in regards to volume growth. This is accomplished by raising the fixed rate and lowering the volumetric rate. If the volumetric rate is reduced to the level of marginal cost, this method is referred to as straight fixed variable (SFV) pricing. If SFV is implemented such that the marginal cost of volume is equal to the volumetric price, then margins will not be increased when volumes increase, or vice versa.

$$P_{Volume} = MR_{Volume} = MC_{Volume} \rightarrow \text{Profits do not change when volume increases.}$$

The use of SFV pricing is attractive because of the ease of implementation versus the development of a RAM. It is, however, not without drawbacks. Revenue decoupling is typically promoted because of a desire towards conservation of energy use. With SFV pricing, a consumer is confronted with a smaller volumetric price, lowering incentive to reduce use. While the price elasticity of demand is inelastic for gas and electricity, it is not zero. SFV pricing will increase quantity demanded, mitigating the intended effect of encouraging conservation.

Another drawback in the implementation of SFV is the negative impact on low volume users, which include many low-income households. Raising fixed rates and lowering volumetric rates will likely cause a welfare transfer from low-income to high-income consumers.

Straight fixed variable rate design is particularly en vogue in the gas distribution industry. Many gas distributors will likely attribute the desire for SFV to conservation; however, motivation might stem from the prevalence of declining average use in the natural gas sector. Consumer adoption of efficient natural gas appliances and the high price of natural gas has led to a situation where customer growth outpaces volume growth in the gas distribution industry. On average, customers are using less natural gas. Gas distributors benefit by having more weight on the faster growing output versus the slower one. SFV allows revenues to increase faster than would previously have been the case.<sup>3</sup>

---

<sup>3</sup> SFV also allows for more stable revenues, which is beneficial.

## **2. History of Revenue Adjustment Mechanisms in the United States**

Revenue decoupling began in California. Pacific Gas and Electric, one of the largest utilities in North America, decoupled natural gas sales in 1978 and electric sales in 1982. The 1982 decision established the Electric Revenue Adjustment Mechanism (ERAM) in preparation for a conservation push in California. The California Public Utilities Commission provided the rationale behind the ERAM by stating that it was “especially difficult in this period to make accurate sales estimates because of the state of the economy and the inability to accurately quantify the effects of conservation which we are expecting our utilities to promote even more vigorously in the future.”

All of California’s major energy utilities had some form of decoupling in the 1980s and 1990s. These plans were sustainable for long periods because the adjustment mechanism was based on the change in a macro-economic price indicator such as GDPPI or CPI. This allowed revenue to escalate at the rate of inflation.

The conservation results during this period are impressive. From 1980 to 2005, electric use per customer has remained constant in California, whereas in the rest of the United States there has been a fifty percent increase over the same period.

California was not the only jurisdiction that embarked upon revenue decoupling. In 1989, Niagara Mohawk implemented the Niagara Mohawk Electric Revenue Adjustment Mechanism (NERAM). The NERAM set the stage for all of New York’s major IOUs to implement revenue decoupling mechanisms throughout the 1990s. In the Northwest region of the United States, Puget Sound Power & Light was regulated under the Periodic Rate Adjustment Mechanism (PRAM) from 1991 to 1995 and Portland General Electric had the Revenue Decoupling Mechanism (RDM) from 1995 to 1997. The Maine Public Utilities Commission used an ERAM to escalate Central Maine Power’s revenues from 1991 to 1993.

### **3. Recent Developments**

Consideration and implementation of revenue decoupling mechanisms has dramatically increased in recent years. The spread spans the entire country, as well as spanning the services utilities provide. Gas distribution has dominated this movement, presumably as a defense against declining average use, but current plans can be found for power distributors as well as vertically integrated power utilities. RAMs currently in operation can be found in California, Idaho, Colorado, Connecticut, Arkansas, Illinois, Maryland, New York, New Jersey, North Carolina, Oregon, Vermont, Utah, and Washington. There are a number of generic proceedings in numerous states that are being undertaken to assess the merits and pitfalls of revenue decoupling, as well as a number of proposals currently working their way through the rate case process.

Two types of currently operating RAMs are prevalent. The first is the “California” model whereby the RAM is based on a macro-economic price indicator, implying that revenues will be escalated by the measure of inflation chosen. The second type is the revenue per customer (RPC) freeze. In an RPC freeze, the RPC amount is determined and set for the entirety of the plan. At each adjustment period (monthly, quarterly, or annually), revenues are adjusted to bring the utility back in line with the allowed RPC. This type of adjustment mechanism implies revenue growth will equal customer growth.

Other escalation methods are available such as forecasting total costs or a hybrid method whereby capital expenditures are forecasted but operation and maintenance expenses are capped under a RAM. Additionally, there is the indexing method which estimates future cost growth by calculation of industry price inflation and productivity trends. This method has been employed in California to demonstrate the reasonableness of the macro-economic indicator approach and has recently been implemented for Enbridge Gas Distribution in Ontario. Indexing has formed the basis for numerous price cap plans. The indexing approach will be discussed in more detail in the next section of this paper.

#### 4. Indexing Approach to Revenue Escalation

The indexing approach to RAM design aims to simulate the trend in utility costs that would occur in a competitive market. This trend is then the basis for revenue escalation. Revenues that are correctly specified allow the utility to fully recover capital and O&M costs, including the agreed upon return on equity. Continuation of the allowed ROE throughout subsequent years requires revenue escalation equal cost escalation for each year of the plan.

Economic theory suggests in a competitive market, costs will increase by the trend in input price inflation minus the total factor productivity trend plus the trend in a cost elasticity weighted output quantity index.

$$\begin{aligned}RAM &= \Delta Revenue = \Delta Cost \\ \Delta Cost &= \Delta IPI - \Delta TFP + \Delta Y^e \\ RAM &= \Delta IPI - \Delta TFP + \Delta Y^e\end{aligned}$$

*IPI* = company-specific input price inflation

*TFP* = industry total factor productivity

*Y<sup>e</sup>* = company-specific cost elasticity weighted output index

The index approach calculates these terms to determine the anticipated cost growth of the utility in years following the test year. The IPI is determined by calculating the cost shares of the utility for capital, labor, and materials and applying these shares to individual price indexes for each category. This requires caution; a time period must be carefully chosen that reflects the anticipated input price changes of the plan term. A period with similar interest rate, wage, and non-labor price growth is desired.

The Total Factor Productivity (TFP) term is calculated by determining the change in a cost-weighted output quantity index relative to an input quantity index. It is important that the TFP is external to the utility; otherwise cost efficiency incentives will be reduced.

$$\Delta TFP = \Delta Y^e - \Delta X$$

here, *X* is a cost-weighted input quantity index of the external sample.

A hybrid approach to indexing is also available. This method is more applicable to bundled power providers. Vertically integrated power utilities will require capital investments that fluctuate more than power or gas distributors. It is possible for state commissions and regulated utilities to agree upon capital spending budgets and put O&M expenses under a RAM. The same calculations apply with some modifications, the IPI is calculated with the cost shares of O&M expenses, and the TFP term becomes an O&M partial factor productivity index (PFP) where the input quantity index no longer includes capital quantity.

The indexing approach can also be used to assess the reasonableness of simpler methods, such as a “California” approach or a RPC freeze. If industry price inflation equals the macro-economic indicator then the “California” approach implies that  $\Delta TFP = \Delta Y^e$ . The RPC freeze approach implies that  $\Delta IPI = \Delta TFP$ , if volume and customers grow at the same trend. To the extent that

reality corresponds with these relationships the simpler RAMs will be compensatory and function correctly. In many cases these relationships are not true, particularly off the mark is the RPC freeze, and in these cases an alternative method should be advocated.

## 5. The Design of an Appropriate RAM for Central Vermont Public Service

The Vermont Department of Public Service (DPS) is conducted a 2008 rate case in regards to Central Vermont Public Service (CVPS).<sup>4</sup> CVPS is primarily a power distribution utility and operates within the state of Vermont. It generates approximately 6.5% of its power supply needs, mainly from small hydro stations. The majority of its power supply is purchased from Vermont Yankee Nuclear Power Station and Hydro-Quebec. CVPS serves approximately 158,000 customers and employs about 550 people.

On March 28, 2008 William J. Deehan, Vice President of Power Planning and Regulatory Affairs, gave direct testimony on behalf of CVPS addressing the company's proposal regarding the escalation of revenues for its proposed three year revenue decoupling plan.<sup>5</sup> Mr. Deehan proposed an annual escalation for base rate revenues of approximately 6.5%; this cap on revenues was termed the "Unicap".

The DPS responded to CVPS's proposal with testimony by Ron Behrns on May 30, 2008. Mr. Behrns claims that CVPS's Unicap proposal of 6.5% escalation is too brisk. The DPS instead proposed to escalate CVPS revenue by CPI with a productivity adjustment of 50% of CPI growth. This equates the DPS proposal for the RAM to be CPI growth divided by two.<sup>6</sup> Mr. Behrns cited 2007 CPI growth as approximately 4.05% and so his proposed RAM is 2.025%.<sup>7</sup>

In summary the two proposals are,

$$RAM^{CVPS} = 6.50\%, \text{ versus } RAM^{DPS} = 2.025\%$$

Index theory allows for the evaluation of these proposals and enables a determination of which proposal is compensatory yet challenging, or if a RAM in between these proposals is more appropriate. Again, this requires an estimation of input price inflation, productivity, and output growth.

The input price inflation is estimated for the 2000-2006 time period using CVPS's actual cost shares. The growth in GDPPI is used for the materials input price, the growth in a regionalized industry-specific employment cost index (ECI) from the Bureau of Labor Statistics is used for the growth in labor, and a capital service price index is developed to serve as the basis for the capital price. These terms are compiled into an IPI index using the Törnqvist indexing method. Thus:

---

<sup>4</sup> Docket No. 7336, Petition of Central Vermont Public Service Corporation for Approval of an Alternative Regulation Plan.

<sup>5</sup> The plan also included two one-year extensions available at CVPS's discretion.

<sup>6</sup> Productivity trends are typically not sensitive to inflationary conditions. This plan would expose CVPS to risks associated with inflation.

<sup>7</sup> Additionally, he includes an adjustment for specific capital additions for Automated Metering Infrastructure (AMI).

$$\Delta IPI = \left( CS_{t-1}^{material} + CS_t^{material} \right) * \ln \left( \frac{GDPPI_t}{GDPPI_{t-1}} \right) + \left( CS_{t-1}^{labor} + CS_t^{labor} \right) * \ln \left( \frac{ECI_t}{ECI_{t-1}} \right) + \left( CS_{t-1}^{capital} + CS_t^{capital} \right) * \ln \left( \frac{WKS_t}{WKS_{t-1}} \right)$$

Where CS stands for cost shares and WKS is the capital service price.

TFP is calculated by taking an average of 73 U.S. power distributors for a ten year period (1996-2006). A longer period is preferred for the TFP so that short-term business fluctuations and infrastructure investment can be smoothed. The calculation of each utility's TFP requires a cost-elasticity weighted output index and a cost-weighted input quantity index. The cost elasticities for the output index are derived from a translog cost function. The model estimates a 70% weight on customers and 30% on volumes. The input quantity index is a cost weighted combination of labor, materials, and capital. Thus:

$$\Delta TFP = .70 * \ln \left( \frac{N_t}{N_{t-1}} \right) + .30 * \ln \left( \frac{V_t}{V_{t-1}} \right) - \left[ \left( CS_{t-1}^{material} + CS_t^{material} \right) * \ln \left( \frac{XM_t}{XM_{t-1}} \right) + \left( CS_{t-1}^{labor} + CS_t^{labor} \right) * \ln \left( \frac{XL_t}{XL_{t-1}} \right) + \left( CS_{t-1}^{capital} + CS_t^{capital} \right) * \ln \left( \frac{XK_t}{XK_{t-1}} \right) \right]$$

The  $Y^e$  term is the first term of the TFP equation so,

$$Y^e = .70 * \ln \left( \frac{N_t}{N_{t-1}} \right) + .30 * \ln \left( \frac{V_t}{V_{t-1}} \right)$$

The calculation of these three terms estimates the cost escalation that CVPS would be expected to encounter in the coming years. The results for each term show,

$$\Delta IPI = 3.3\%, \Delta TFP = 1.2\%, \Delta Y^e = 1.2\% \\ RAM^{index} = 3.3\% - 1.2\% + 1.2\% = \underline{3.3\%}$$

The indexing method estimates that cost growth in a perfectly competitive industry would approximate 3.3%. It appears that a compensatory solution to the two proposals is somewhere in between the 2.025% escalation proposed by the DPS and the 6.5% proposed by CVPS.

## **6. Conclusion**

The decoupling of revenues from sales volume is an important possibility in the regulation of utility services. An essential part of a revenue decoupling plan is the revenue adjustment mechanism. This mechanism can be based on simple methods such as CPI growth, RPC freeze, or by more rigorous indexing methods.

The indexing approach is a more precise assessment of expected cost growth. In a time when inflation may be increasing, the revenue per customer freeze is un-compensatory for the vast majority of gas and power utilities. This fact is limiting the spread of revenue decoupling. More compensatory is the use of macro-economic inflation measures; however, this should be determined on a case-by-case basis.

The indexing approach can be used by itself or demonstrate the foundation for simpler mechanisms. As illustrated in the current CVPS case, the use of a CPI escalation would be too generous to CVPS and be detrimental to Vermont electric customers. Likewise, dividing CPI by two and using that for the allowed escalation is also not a fair resolution. The use of the slower growing GDPPI or the use of the indexing result itself is more appropriate.

The determination of escalation mechanisms is complex. It is a function of cost shares, input price growth, output growth, and the regulatory circumstances of the past and the proposal at hand. One plan does not fit all. The lack of ingenuity and scientific foundations in this arena has limited the prevalence of revenue decoupling and its environmental and cost-efficiency benefits.

## References

- [1] American Gas Association. "States with Non-Volumetric Rate Designs For Natural Gas." May 2008. Print.
- [2] Carter, Sheryl, Devra Wang, and Audrey Chang. "The Rosenfeld Effect in California: The Art of Energy Efficiency." NRDC Presentation.
- [3] Kushler, Martin, Dan York, and Patti Witte. "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives." *American Council for an Energy-Efficient Economy*, Report Number U061 (2006). Print.
- [4] Lowry, Mark N., Lullit Getachew, David Hovde, and Steve Fenrick. "AltReg Rate Designs Address Declining Average Gas Use." *Natural Gas & Electricity* (April 2008): 13-18. Print.
- [5] NARUC. "Decoupling For Electric & Gas Utilities: Frequently Asked Questions." Sept. 2007. Print.
- [6] Schmidt, Michael R. *Performance-Based Ratemaking: Theory and Practice*. Vienna, VA: Public Utility Reports, 2000. Print.
- [7] Törnqvist, L. "The Bank of Finland's Consumption Price Index." *Bank of Finland Monthly Bulletin* 10 (1936): 1-8. Print.
- [8] Varian, Hal R. *Microeconomic Analysis*. New York: W.W. Norton, 1984. Print.