REVIEW OF DISTRIBUTION REVENUE DECOUPLING MECHANISMS

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EXECUTIVE SUMMARY

The government of Ontario has recently initiated policies that will redouble provincial efforts to promote a cleaner, more efficient energy economy. Spending on electricity conservation and demand management ("CDM") and natural gas demand side management ("DSM") programs is expected to increase substantially. These initiatives will slow growth in the deliveries of Ontario energy distributors and can thereby reduce their earnings between rate cases. While conventional regulation provides some remedies for this problem, regulators in Ontario and many other jurisdictions are experimenting today with measures that target the problem of slowing demand growth by decoupling utility revenues from system use. This paper reports on an investigation of the established approaches to decoupling to consider what strategy makes sense in Ontario where, as noted below, decoupling measures are already in use.

What is Revenue Decoupling?

The basic idea of revenue decoupling is to weaken the link between the earnings of a utility and the use of its system. The link is a strong one under common designs of rates for utility services. The cost of energy distribution and customer care is driven, in the short run, chiefly by customer growth and is largely fixed with respect to system use. Distribution cost is highest for, and therefore revenue is drawn chiefly from, small volume (*e.g.* residential and general service) customers. A high percentage of the revenue from these customers is traditionally drawn from volumetric (*e.g.* $/kWh) charges. This makes utility earnings sensitive to the trend in the average system use of small volume customers. A material decline in average use can prompt utilities to request rate rebasings frequently.

Conventional utility regulation provides some protections from average use declines, including the use of forward test years in rate rebasings. However, regulators increasingly employ measures designed to target earnings attrition from slow volume growth when this becomes a problem. Three approaches to revenue decoupling are well established.

- Lost revenue adjustment mechanisms ("LRAMs") compensate utilities for lost margins due to their CDM/DSM programs. These mechanisms require estimates of energy and peak load savings from the programs.
- Decoupling true up plans have two basic components. A "revenue adjustment mechanism" adjusts rates to reflect escalating cost pressures. A "decoupling true up mechanism" uses a variance account to cause revenue to track allowed cost more closely. "Full" decoupling true up mechanisms decouple earnings from *all* sources of demand shifts that can cause revenue variances. "Partial" decoupling mechanisms exclude revenue variances that are attributable to specific demand drivers (*e.g.* weather).
- Straight fixed variable ("SFV") pricing is an approach to rate design that eliminates volumetric charges. The revenue shortfall is usually recovered from higher fixed charges. These charges are usually the same for all customers in a service class but can instead vary in some rough fashion with a customer's historical usage pattern.

Criteria for Choosing a Decoupling Approach

Criteria are needed to choose between alternative decoupling approaches. The report emphasizes the following criteria:

- Administrative cost;
- Ability to remove disincentives for utilities to pursue a wide range of CDM/DSM initiatives; and
- Ability to alleviate earnings attrition from external sources of average use decline.

SFV pricing has the lowest administrative cost. LRAMs have the highest cost due to their reliance on CDM/DSM savings estimates that can be complex and controversial. This tends to confine their application to conventional CDM/DSM programs, where savings are easier to measure. However, the cost of savings estimates will be incurred anyways if the utility has a CDM/DSM incentive mechanism that also uses these estimates. Decoupling true-up mechanisms involve an administrative cost similar to that of other automatic rate adjustment mechanisms. The revenue adjustment mechanism involves some cost to develop and administer, but there is little *incremental* cost for this in a jurisdiction that already uses indexed price cap plans.

All three established approaches to decoupling are effective at removing utility disincentives to pursue conventional CDM/DSM programs. However, the high administrative cost of LRAMs makes them less suited for removing disincentives for less conventional utility CDM/DSM initiatives. Decoupling true up plans and SFV pricing remove disincentives for a much wider range of initiatives, but SFV pricing restricts the use of distribution rate design to further CDM/DSM objectives.

LRAMs are not useful for reducing earnings attrition in the face of declining average use that is due to external business conditions rather than utility initiatives. Decoupling true up plans and SFV pricing are useful for this purpose and are equally serviceable in this regard.

Consider, finally, that the established decoupling approaches involve idiosyncrasies that limit their appeal. Decoupling true up plans achieve revenue stability at the expense of rate stability. Implementation of SFV pricing with uniform fixed charges for the customers in a service class can involve sharp increases in fixed charges that are unwelcome to small-volume customers. SFV pricing and decoupling true up plans both weaken utility incentives to offer market-responsive pricing to price sensitive customers.

Decoupling Experience

Some form of revenue decoupling is used today in almost all U.S. jurisdictions that have large scale CDM/DSM programs. However, incentive mechanisms for CDM/DSM performance are also widely used and these can provide some compensation for lost revenues in the absence of decoupling measures. These incentive mechanisms get much of the credit for the size that several large scale programs have reached.

Decoupling true up plans are the single most widely used approach to decoupling in the United States today. They are now mandatory in three of the leading CDM/DSM states: California, New York, and Massachusetts. Many approved plans exclude large volume customers.

The true up approach to decoupling originated in California in the late 1970s as a means to encourage conservation and contain the risk of experimental rate designs with high usage charges. Many current plans in other states are pilots, and only a few other states have had much experience with the plans. Eight states that have tried decoupling true up plans have approved additional plans but four have not.

The popularity of decoupling true up plans can be traced to a variety of circumstances.

- CDM/DSM programs in many states are administered by independent agencies. LRAMs are not applicable in this situation, but the other two approaches can mitigate declines in average use that result from large-scale independent programs and other causes.
- Decoupling true up plans have lower administrative cost than LRAMs, and regulators have recognized their ability to remove disincentives for a wider range of utility CDM initiatives.
- Undesirable features of SFV pricing, such as high fixed charges and low usage charges that don't further CDM/DSM goals, are sidestepped.
- Many state commissions have jurisdiction over just a few utilities, and therefore do not place great value on the administrative cost advantage of SFV pricing.

Application to Ontario: Gas Distribution

We reviewed the situation of Ontario distributors and found several conditions of their operating environment that are especially important to the choice of a decoupling strategy. The two largest distributors in the province, Enbridge and Union, have large scale DSM programs. For this and other reasons, average use by residential customers is declining. The Board prefers multiyear incentive regulation plans for these companies, and this compounds the potential problem of earnings attrition between rate cases. There are few utilities to regulate, so the administrative cost advantages of SFV pricing are limited.

The Board's current decoupling approach for these companies has the following features.

- Rate rebasings have forward test years.
- Lost revenue from distributor DSM programs is recovered using LRAMs.
- "Shared Savings" DSM incentive mechanism are used and these also currently require estimates of DSM savings.
- There are partial (weather normalized) decoupling true up plans.

- There are high fixed charges for residential distribution service.

This approach to decoupling is sensible, but the following two changes merit consideration.

1. Elimination of LRAMs would yield modest administrative cost savings, especially if the shared savings mechanism was revised in such a way that estimates of DSM savings were no longer required.
2. Full decoupling would remove disincentives to experiment with rate designs that better foster provincial DSM goals. These experiments could include a reduction in residential customer charges and an increase in usage charges that would reduce the payback period for DSM investments. Savings in the cost of funds that result from reduced revenue risk could be shared with customers.

Application to Ontario: Power Distribution

The following conditions were recognized in the study which are especially relevant to the choice of a decoupling strategy for Ontario power distributors. The provincial government is an aggressive proponent of electricity CDM. Utilities have large and growing CDM programs. Other federal and provincial initiatives also slow growth in average use. Average use by residential customers appears to be declining materially. The current multiyear rate plans used by the Board don't compensate power distributors for any decline in their average use. There are about eighty distributors, which is a daunting regulatory challenge.

The Board currently uses the following decoupling measures in its regulation of power distributors.

- Rate rebasings use forward test years.
- Lost revenue from distributor CDM programs can be recovered using LRAMs. However, most provincial distributors have not yet made LRAM filings.
- "Shared Savings" CDM incentive mechanisms are available, and these also require estimates of CDM savings.
- Some distributors have high fixed charges for residential distribution service.

A number of possible improvements in the decoupling strategy for power distributors in Ontario were identified in the study. Most notably, LRAMs can be replaced with SFV pricing or partial decoupling true up plans. This would have the following benefits.

- Administrative cost savings could be material given the large number of distributors.
- Disincentives could be removed for wider range of utility CDM efforts.
- Earnings attrition from external drivers of declining average use would be mitigated.
- The price cap plans currently used to regulate power distributors can be easily converted to decoupling true up plans.

Taking the additional step to full decoupling would, by reducing the risk of weather fluctuations, facilitate distribution rate designs that better promote provincial CDM goals. The rate design innovations could include peak load pricing and/or higher volumetric charges. Any savings in capital cost that result from reduced revenue risk could be shared with customers.

1. INTRODUCTION

The government of Ontario has recently initiated policies that will redouble provincial efforts to promote a cleaner and more efficient energy economy. Spending on electricity conservation and demand management ("CDM") and natural gas demand side management ("DSM") programs is expected to increase substantially. These initiatives can reduce the earnings of Ontario energy distributors by slowing growth in the use of their systems. While traditional regulation provides some remedies, regulators across North America are experimenting today with mechanisms that directly address the problem of slowing demand growth by decoupling utility revenues from system use. The Ontario Energy Board uses several approaches to decoupling in its regulation of provincial energy distributors. Other methods are used in other jurisdictions.

Pacific Economics Group ("PEG") Research LLC is a leading provider of alternative regulation consulting services. We have been retained to advise the Board on decoupling issues. The deliverables include a report and a presentation in Toronto that explain decoupling concepts, recount decoupling experience, and consider improvements in the decoupling mechanisms for Ontario energy distributors. This is the final report on our work.

The plan for the paper is as follows. In Chapter 2 we describe the major approaches to revenue decoupling and discuss the rationale for decoupling and criteria for choosing between alternative approaches. In Chapter 3, we discuss decoupling experience including key decoupling precedents. In Chapter 4 we consider in more detail some plan design issues with respect to a popular approach to decoupling. In Chapter 5, we consider the approaches to decoupling used in Ontario and the merits of alternative approaches.

2. REVENUE DECOUPLING BASICS

This section provides an introduction to the most established mechanisms for decoupling. To provide context, we begin by describing the conventional approach to rate regulation and its incentive regulation ("IR") variant. We then describe in some detail the major approaches to revenue decoupling. There follows a discussion of the rationale for decoupling and of criteria for comparing decoupling approaches.

2.1 CONVENTIONAL REGULATION

In North America, rates for utility services are set periodically in adjudicated hearings called rate cases (also known as rate "rebasings"). A revenue target, called the "revenue requirement", is established for a certain year, called the "test year", to recover an estimate of the cost of service. The year in which new rates take effect is sometimes called the "rate year".

Bills for customers in a given class typically have several charges that are designed to recover the revenue requirement. There is usually a "fixed" charge (sometimes called a customer charge) that is so-called because it doesn't vary with system use. The bill will also include one or more charges that do vary with use. The most common usage charges are those for the volume of service ("volumetric charges") and the peak level of demand ("demand" charges). The approved rates for a service class are designed to recover the revenue requirement for that class given assumptions about the number of customers served and system use. A utility's revenue is the product of the rates thus established and the corresponding quantities of service. These quantities are sometimes called "billing determinants".

Test years can be forward or historic. A historic test year is typically a year ending a few months before the rate case filing. Cost in this year may be adjusted to reflect known and measurable changes going forward, and system use and certain costs may be normalized. However, rates are not usually based on forecasts of rate year billing determinants.

A forward test year is a year that begins after the rate case filing date and is often a year that begins about the time that the rate case is expected to conclude. The test year would in this case be the same as the rate year. The revenue requirement and billing determinants in a forward test year ("FTY") are supposed to reflect forecasts of the business conditions that are expected in that year. Rates can therefore, in principle, reflect the slowdown in system use resulting from CDM/DSM programs and other factors.

Bills of energy distributors typically have separate charges to recover the cost of any energy commodities that have been procured for the customer and the cost of capital, labor, and other inputs required to operate their systems.[1] The rates that recover the costs of non-energy inputs are commonly called "base rates" or "distribution rates". Base rate revenues are sometimes called "margins". Rates for the cost of energy procurement are commonly subject to true ups to recover the actual cost of energy procured, less any prudence disallowance. Base rates, on the other hand, have traditionally been reset only in rate cases.

A few jurisdictions in North America --- and many more in countries overseas --- use rate "plans" that schedule rate cases infrequently. These plans commonly feature mechanisms that adjust rates automatically between rate cases for changes in business conditions that can cause attrition in the earnings that utilities use to compensate holders of their debt and equity. These are sometimes called attrition relief mechanisms. Some causes of earnings attrition (*e.g.* slow volume growth) are on the revenue side whereas others (*e.g.* input price inflation) are on the cost side.

Attrition relief mechanisms that cap *rate* growth are sometimes called "price caps". Mechanisms that cap *revenue requirement* growth are sometimes called "revenue caps". Many price caps, and some revenue caps, have an escalation formula like inflation – X, where the X term is called the "X factor". A price cap with a formula like this is sometimes called a "price cap index" ("PCI"). The years of a rate plan during which the attrition relief mechanisms are applicable are sometimes called the "attrition years".

The typical duration of a rate plan is three to five years. Plans usually have provisions, sometimes called "Z factors", for rate adjustments in the event of extraordinary changes in business conditions. Additionally, some plans feature "off ramp" provisions that permit a suspension of the plan, and an immediate rate case, if earnings are unusually high or low. Barring a Z factor or off ramp event, the ability of a conventional rate plan to

[1] Costs of energy procurement are conventionally recovered using volumetric charges. Volumetric charges are sometimes called "energy" charges for this reason, even when they apply to distribution services.

compensate a utility for slow growth in system use depends on the design of the attrition relief mechanism.

2.2 Revenue Decoupling

The term revenue decoupling refers to a family of regulatory provisions that are expressly designed to relax the link between a utility's base rate revenue and customer use of its system. Three approaches to decoupling have been established that, with differing degrees of effectiveness, accomplish this goal: lost revenue adjustment mechanisms ("LRAMs"), decoupling true ups, and straight fixed variable ("SFV") pricing. We discuss each in turn.

2.2.1 Lost Revenue Adjustment Mechanisms

Under LRAMs, a utility is explicitly compensated for the lost margins that are estimated to result from its programs to promote energy efficiency ("EE") and possibly other goals, such as peak load management or load displacement generation ("LDG"). This requires estimates of energy savings and other quantitative impacts of the programs. Compensation for lost margins is sometimes effected through a specialized rate adjustment mechanism called, variously, a rate "tracker" or "rider", which can adjust rates between rate cases. In the absence of a decoupling mechanism that is supplemental to the LRAM, the utility is fully at risk for unforeseen fluctuations in demand due to weather, local economic activity, power market prices, and other drivers of the demand for utility services. LRAMs are part of the packages currently used to protect Ontario gas and electricity distributors from slow volume growth, as we discuss in Sections 5.2.4 and 5.3.4.

2.2.2 Decoupling True up Plans

A decoupling true up plan commonly has two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). This structure separates the job of attrition relief into two components. The decoupling mechanism addresses any *revenue-related* attrition between rate cases, leaving the other mechanism to provide relief for cost-related attrition.

<u>Revenue Decoupling Mechanism</u>

The RDM makes regularly scheduled adjustments to rates which cause a utility's actual revenues to track more closely the revenue that regulators deem to be warranted by cost conditions. True up mechanisms usually involve a variance account in which past differences between actual revenue and the revenue requirement are entered.[2] The accumulated net variance, together with any interest that may be paid, provides the basis for a periodic rate adjustment. The adjustment is usually undertaken with a rider to the volumetric charge. Bills can include a separate line item to identify this charge.

As with other rate riders, the recovery of the account balance requires a specification of the future use level. To the extent that the usage specification reflects the trend in system use, this specification is really part of the decoupling mechanism. The future use specification may take the form of a sophisticated volume forecast but need not be because the true up mechanism is available as a backstop.

True ups may be made monthly, quarterly, semi-annually, or annually. For example, rates may be reset in January to effect a reconciliation of base rate revenues and the revenue requirement in the previous calendar year. Rate adjustments for purposes of decoupling can be synchronized with adjustments made for other reasons, such as the operation of an attrition relief mechanism, so that there is no increase in the frequency of rate adjustments.

Some true up mechanisms are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups may be allowed only for the difference between actual weather normalized revenue and the revenue requirement. A utility in this case continues to experience fluctuations in revenues due to weather conditions. A RDM that accounts for all sources of demand fluctuations may be called a "full" true up mechanism.

The size of rate adjustments that are caused by true ups are sometimes limited arbitrarily. For example, the size of the rate increase that is allowed in a given year may be capped at 5%. Caps may be soft or hard. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be recovered immediately. "Hard" caps do not.[3] Some mechanisms make adjustments only when revenue variances fall outside (*i.e.* are larger or smaller than) a certain range of smaller variances that is called a "deadband".

[2] We also count as true up plans the plans for gas and electric utilities in Vermont wherein rates are adjusted each year to collect an index-adjusted base rate revenue requirement using a forward test year.
[3] One company operating under soft caps is Delmarva Power & Light (MD). An example of a company operating under hard caps is Wisconsin Public Service.

True up mechanisms can also vary in terms of the service classes for which revenues are pooled for true up purposes. These service class groupings are sometimes called "baskets". In some plans, all service classes are placed in the same basket. In that event, a downturn in industrial demand could raise residential rates. In other plans, multiple baskets are created to insulate customer from fluctuations in the demand for service classes in other baskets. At the extreme, each service class has its own basket.

The decoupling process for a hypothetical Ontario electric utility is illustrated in Figure 1. We suppose that the utility has a full revenue decoupling true up plan for residential and commercial customers and that there is one service basket for all of these customers. The revenue requirement for these services in 2010 is $100,000,000 and grows by $5,000,000 in 2011 and 2012. Revenue, which fluctuates with weather conditions and is also influenced by CDM/DSM programs, falls short of the revenue requirement by $5,000,000 in 2010. The shortfall is placed in a variance account and rates are raised at the beginning of 2011 in an attempt to recover this balance. In this year, the actual revenue is less than the sum of the revenue requirement and the indicated correction by $2,500,000. This smaller revenue shortfall is placed in the variance account and rates are raised in 2012 to recover the balance. Actual revenue in 2012 is less than allowed revenue by $5,000,000 and this shortfall is placed in the variance account for recovery in 2013. The net effect of the decoupling mechanism is to cause revenue to track the revenue requirement more closely than it otherwise would.

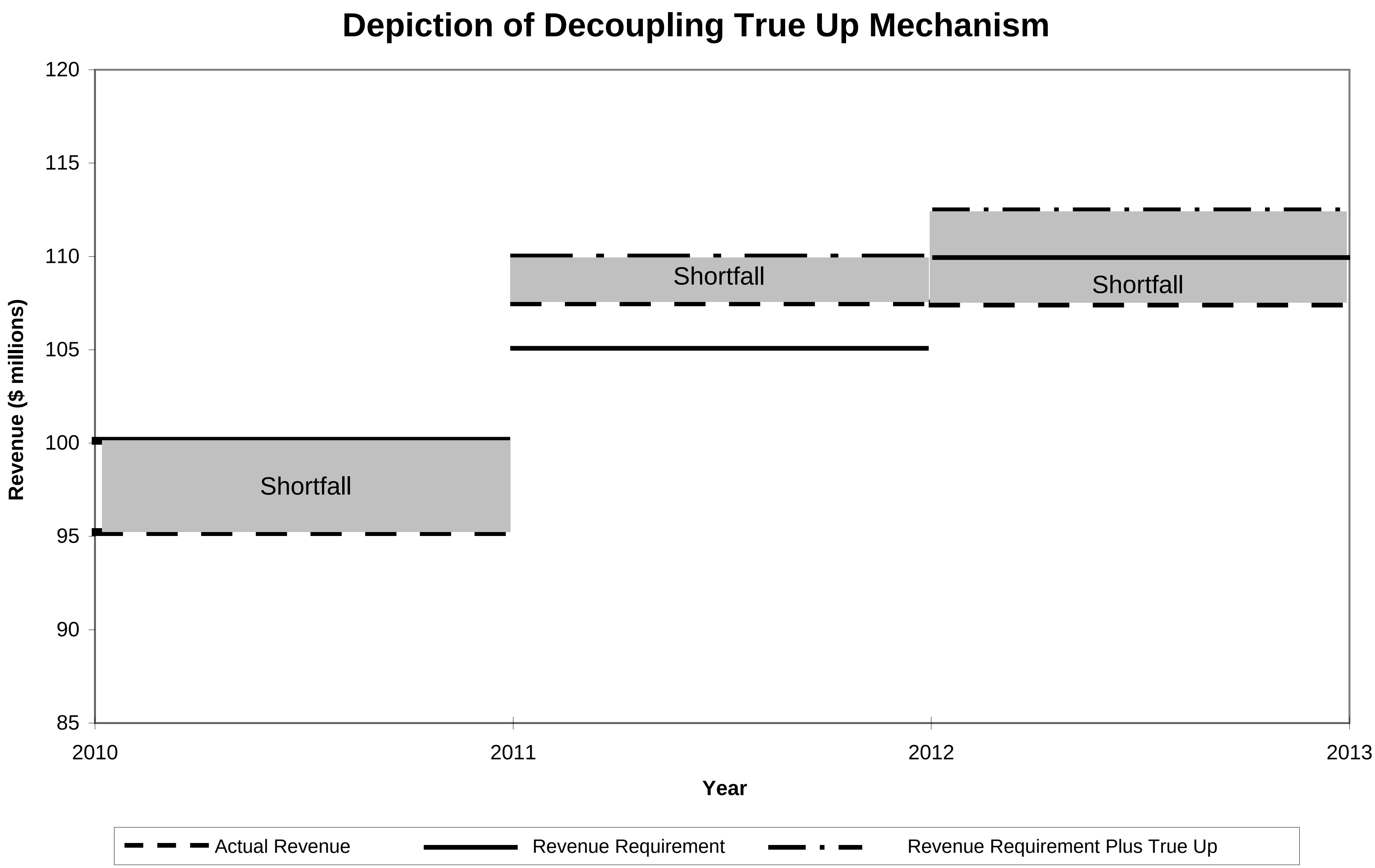
Revenue Adjustment Mechanisms

The RAM component of a decoupling plan escalates rates between rate cases to reflect changes in business conditions that drive utility cost.[4] This is a critically important feature of a decoupling true up plan. In the United States, where multiyear rate plans are not a standard part of energy utility regulation in most states, several decoupling initiatives have foundered on the inability of parties to agree on the design of (or even the need for) such mechanisms.[5]

[4] This task is sometimes referred to as "recoupling". For early discussions of recoupling see Eric Hirst, *Statistical Decoupling: A New Way to Break the Link Between Energy Utility Sales and* Revenues, ORNL CON-372, Oak Ridge National Laboratory, 1993 and Joseph Eto, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling*, Lawrence Berkeley Laboratory paper LBL-34555 UC-350, January 1994.

[5] A good example is Order 19563 in Docket 3943 of the Rhode Island Public Utilities Commission dated January 29, 2009 which rejected a decoupling true up plan for National Grid's gas utility.

Figure 1



Depiction of Decoupling True Up Mechanism
120
115
110
105
100
95
90
85
Revenue ($ millions)
Shortfall
Shortfall
Shortfall
2010
2011
2012
2013
Year
Actual Revenue
Revenue Requirement
Revenue Requirement Plus True Up

To understand the special need for a RAM in a decoupling true up plan, note first that if a utility's billing determinants (*e.g.* its delivery volumes, peak demands, and number of customers served) are growing, rates will actually *decline* under a decoupling true up plan absent some form of revenue requirement escalation because revenue is growing whereas the revenue requirement is static. A utility's cost normally rises due to some combination of input price inflation, plant additions, and output growth.[6] In the few decoupling true up plans that have no RAM, utilities therefore typically file annual rate cases.[7]

RAMs can substitute for rate cases as a means to adjust utility rates for trends in input prices, customer growth, and other external business conditions that drive utility cost. This makes it possible to extend the period between rate cases without relaxing the just and reasonable standard for regulation. Performance incentives can be strengthened and regulatory cost trimmed. When these mechanisms are not designed to make adjustments for multiple cost drivers, utilities usually retain the right to file rate cases during the decoupling plan and frequently do.

Relief from cost-related attrition can be achieved in two fundamentally different ways. The most common approach is to escalate the revenue requirement using some form of revenue cap. Rates are then adjusted to be more reflective of the new revenue requirement. This is the general approach to cost attrition relief that is used by Enbridge Gas Distribution, as we discuss further in Section 5.2.4 below.

An alternative and rather novel approach to cost attrition relief is used by Union Gas. Rates are escalated by a *price* cap index that is designed to provide relief only for changes in business conditions that drive *cost* growth. There are, additionally, adjustments to rates to reflect the average use trends.[8]

Several approaches to revenue cap design have been established. Some revenue caps adjust the revenue requirement formulaically to reflect new information (information obtained *after* the rate plan starts) about the business conditions that drive utility cost. Some of these formulaic revenue caps make explicit adjustments for price inflation and customer growth. We will call this approach to revenue cap design "full indexation". Other formulaic

[6] Throughout the paper, the term input price inflation denotes nominal input price inflation.
[7] See, for example, the recent decoupling experience of Central Hudson Electric & Gas and Consolidated Edison of New York.
[8] See Section 5.2.4 for further discussion.

revenue caps escalate the revenue requirement only for price inflation. We will call these "inflation only" revenue caps.

A third kind of formulaic revenue caps is one that escalates the revenue requirement only for customer growth. Since this latter approach effectively freezes the revenue requirement per customer we will call it the "revenue per customer ("RPC") freeze" approach. The revenue requirement in an attrition year of the rate plan equals the (frozen) RPC times the current number of customers served. An RPC freeze may apply to the *total* revenue per customer. The RPC formula may, alternatively, be applied to individual rate classes. An advantage of the latter approach is that it does not require an allocation of the total revenue requirement variance between rate classes.

A second broad category of revenue caps, which we will call "all-forecast" revenue caps, are based solely on forecasts of future cost which are made before the start of the decoupling plan. This is tantamount to a rate case with multiple forward test years. The revenue requirement trajectories produced by this approach typically display a "stairstep" pattern. The stairsteps reflect *expected* changes in business conditions during the decoupling plan and there are no automatic adjustments to the revenue requirement in the event that business conditions turn out to be different from those that were expected. The cost forecasts that provide the basis for stairsteps are frequently made using formulas similar to those used in formulaic RAMs.[9]

A third broad class of revenue caps, which we will call "hybrid" caps, employ a mix of real-time formulaic adjustments and forecasting methods. Hybrid revenue caps most commonly feature real-time formulaic adjustments for growth in operation, maintenance, and administration ("OM&A") expenses. Some also feature inflation adjustments for plant additions. The target rate of return on rate base is sometimes subject to separate adjustment during the term of the decoupling plan. Forecasts of the depreciation and return on rate base for older plant are easy to prepare and agree on using traditional rate regulation accounting.

A different kind of hybrid revenue cap is used in several jurisdictions overseas, including Australia, New Zealand, and Britain. The revenue requirement is first established for a multiyear period using forecasting methods. Given forecasts of the revenue

[9] For example, a forecast of growth in OM&A expenses might be based formulaically on forecasts of OM&A price inflation and/or customer growth that are available at the time that the RAM is designed.

requirement, billing determinants, and a familiar macroeconomic measure of price inflation such as a consumer price index ("CPI"), a revenue escalation index is developed with general formula

$$\textit{Growth Revenue Requirement} = \textit{growth CPI} - X$$

that has an equivalent net present value. The X factor may be positive or negative and is sensitive to expected capital spending. In this way, the revenue requirement is adjusted automatically for unexpected developments in price inflation.

2.2.3 Revenue Decoupling Through Straight Fixed Variable Pricing

SFV pricing in principle means an approach to rate design that recovers in usage charges (charges that vary with peak demand or the volume of energy delivered) only those costs that vary, in the *short* run, with system use. In most applications, SFV pricing has involved the elimination of volumetric charges to recover the cost of base rate inputs. The lost revenue is recovered by fixed customer charges or by some form of reservation charges that vary with expected peak demand. For residential and smaller business customers, who typically do not have interval meters or other advanced metering infrastructure ("AMI"), SFV pricing involves only higher fixed charges. This means that customers pay a substantial monthly charge regardless of usage and cannot reduce their distribution bills with lower usage. Recovery of the revenue requirement for service classes with SFV pricing is guaranteed.

A decision must be made whether to levy the same fixed charge throughout the year or allow rates to be higher in the peak usage season. A fixed charge that is constant throughout the year promotes bill stability but, for gas customers, can involve higher summer payments than they are used to. Another issue is whether to have the same fixed charge for all customers in a service class. Most SFV rate designs implemented to date have involved the same charge for all customers. This means a large increase in distribution bills for small volume customers and a reduction in bills for large volume customers. However, a "sliding scale" mechanism can be designed that assigns lower fixed charges to customers who have historically had low volumes and higher fixed charges to those who have historically had high volumes.[10]

[10] See, for example, the plan of Oklahoma Natural Gas cited in Table 2 below.

With regard to *cost* attrition relief, this is somewhat less of a concern with SFV pricing inasmuch as there is no concern about having to reduce rates if billing determinants grow. However, it may be noted that SFV pricing has an impact on revenue growth that is similar to a revenue per customer freeze. Base rate revenue grows over time at the pace of customer growth. Any attrition relief that is desired for other business conditions, such as input price inflation, would require a supplemental price cap.

2.3 RATIONALE FOR REVENUE DECOUPLING

2.3.1 AN INTRODUCTION TO UTILITY RATE DESIGN

Rate Design Basics

The rationale for decoupling is rooted in the way that utilities charge for their services. We noted in Section 2.1 above that base rates for utility services commonly involve a mix of fixed charges and usage (*e.g.* volumetric) charges. For most utilities, usage charges collect the lion's share of base rate revenue.

Usage rates sometimes vary with the amount that a customer uses. For example, a volumetric rate may be different for low amounts of usage than for high amounts. The charge associated with usage in each range is sometimes called a "block". Rates that decline with the level of usage are called *declining* block rates. Rates that increase with the level of usage are called *increasing* (or "inverted") block rates. A block that corresponds to the highest level of usage is called the "tail" block.

Volumetric charges have traditionally been used for residential and small business customers rather than demand charges due, in part, to the fact that they have not had the more expensive meters that record peak demand. Demand charges are frequently used for large volume customers, such as auto plants. There is little experience to date with the design of base rates for small volume customers with AMI.

Why Rate Design Matters

The index logic used to design multiyear rate plans in Ontario is useful in explaining why rate design might prompt an interest in some form of decoupling. Because of the flow through of commodity procurement costs via variance accounts, the earnings of distributors depend primarily on the difference between the cost of distribution and customer care services and the base rate revenue that they receive for these services. It can be shown that, for a utility earning a competitive rate of return,

trend Rates = trend Unit Cost

= trend Input Prices – trend Cost Efficiency – trend Average Use. [1]

The trend in base rates must track the trend in the utility's unit cost of base rate inputs. This may be defined roughly as cost per unit delivered (*e.g.* cost per kWh). The unit cost trend of a utility decomposes into the trends in its input prices and cost efficiency and an average use factor. The average use term is the difference between the way that changes in output affect the utility's revenue, on the one hand, and its cost on the other. For an energy distributor, cost is sensitive in the short run to growth in only one output dimension: the number of customers served.[11] Revenue growth is driven in the short run chiefly by growth in the billing determinants of residential and small business customers because these customers account for the bulk of distribution base rate revenue. In these customer classes, base rate revenue is drawn chiefly from volumetric charges. The output differential thus depends primarily on the difference between trends in the volumes delivered to residential and small business customers and in the numbers of these customers. This is mathematically equivalent to the trends in the delivery volume per customer of these service classes, which is sometimes referred to succinctly as "average (system) use".[12]

The growth in the cost efficiency of utilities --- conventionally measured by total factor productivity ("TFP") indexes --- is typically a good bit slower than the inflation in the prices they pay for inputs.[13] In a recent study, a large sample of U.S. power distributors averaged 1.03% TFP growth 1996-2006, whereas input price growth averaged 2.72%.[14] Under these conditions, the output differential can be crucial to the ability of distributors to avoid financial attrition without frequent rate cases.

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[11] Cost growth may also depend, in the long run, on the growth in peak demand and/or the delivery volume.

[12] To demonstrate, consider that the growth in the delivery volume of a given service classes can be measured using natural logarithms as growth Volume = $\ln(V_t/V_{t-1})$. The growth in the number of customers can be measured similarly, as growth Customers = $\ln(N_t/N_{t-1})$. The difference between volume and customer growth is then growth Volume - growth Customers = $\ln(V_t/V_{t-1}) - \ln(N_t/N_{t-1}) = \ln[(V_t/N_t)/(V_{t-1}/N_{t-1})]$ = growth Volume/Customer.

[13] The difference is greater in periods of brisk input price inflation and smaller in periods of slow inflation, since productivity does not characteristically rise and fall with inflation.

[14] Mark Newton Lowry, David Hovde, Lullit Getachew, Steve Fenrick, and Kyle Haemig, *Revenue Adjustment Mechanisms for CVPS*, Pacific Economics Group, June 2008.

Suppose first that there is no multiyear rate plan with a mechanism that provides attrition relief from rising cost pressures between rate cases --- the common circumstance in the United States. If volume per customer growth is *brisk* (*e.g.* 1.5% annually), the difference between input price and cost efficiency growth can be largely or entirely offset and rate cases can be avoided --- especially in periods when input price inflation is slow and/or the utility is not making sizable new investments that slow cost efficiency growth. If volume per customer is *static* rate cases will be needed occasionally, especially in times of brisk inflation or sizable new investments. If volume per customer growth is *declining*, rate cases will be needed frequently, and possibly annually.[15] In the alternative case, where utilities do operate under multiyear rate plans and are compensated for rising cost pressures between rate cases, the utility would still prefer growth in average use but doesn't need it to offset the difference between inflation and cost efficiency growth. However, a *decline* in average use can create earnings attrition between rate cases.

Our discussion suggests that one means of addressing the problem of earnings attrition between rate cases would be to devise a price cap index in which the X factor reflects average use trends as well as cost efficiency trends. The X factor would in this case be higher in a time and place of brisk average use growth and lower in a time and place of declining average use. If a price cap index is designed to reflect only the trend in cost

[15] To better grasp the potential seriousness of declining average use, consider the implications of the following circumstances for a hypothetical energy distributor that pays no income taxes.

- The annual total cost of the distribution system is $100 million.
- The return on rate base accounts for 30% of this cost.
- Equity accounts for 50% of capitalization. Thus, the return on equity accounts for .50·.30· $100,000,000 or $15,000,000.
- The allowed rate of return on equity is 10%. Thus, the equity portion of the rate base is $150,000,000.
- The residential volumetric charge accounts for 40% of base rate revenue.
- A price cap plan fully compensates the utility only for the tendency of cost efficiency to grow more slowly than input prices. Revenue growth is then uncompensatory only to the extent that there is a decline in the residential volume per customer.
- Volume per customer in the residential class is falling by 1% annually.
- For simplicity, the billing determinants for all other services classes grow at the same rate as the growth in the number of customers.

Under these assumptions, billing determinants grow .40*1% = 0.4% more slowly on average than customers do each year. There is thus a 0.40% shortfall in revenue each year due to declining average use. 0.40% of $100,000,000 is $4,000,000. The return on equity is thus 11,000,000, a reduction of 267 basis points.

efficiency, it will not provide adequate attrition relief when average use is markedly declining.

Our discussion of the output differential also sheds light on an important source of utility operating risk. System use fluctuates from year to year due to fluctuations in demand drivers, such as weather, local business activity, and energy commodity prices, that are difficult to predict accurately. With traditional rate designs, fluctuations in system use cause base rate revenue to be low in periods of low demand and high in periods of high demand whereas the cost of base rate inputs is invariant with respect to these fluctuations. Thus, demand fluctuations can be an important source of earnings risk to the extent that base rate revenue is recovered via demand and volumetric charges rather than fixed charges.

2.3.2 CDM/DSM Promotion

The most widely advanced rationale for revenue decoupling is its ability to facilitate greater efficiency in the use of electricity, natural gas, and the transmission and distribution systems that deliver these commodities. Initiatives by utilities that encourage less use of their systems will slow growth in average use between rate cases. This reduces earnings and constitutes a disincentive for utilities to do their part to promote CDM/DSM goals.

The three established approaches to revenue decoupling that we have discussed can compensate the utility for slowing growth in average use, thereby removing their disincentive to promote CDM/DSM goals. The benefits of removing disincentives can be manifested in several ways. Assuming that the utility provides CDM/DSM programs, the bills of program participants who reduce energy purchases can be lower. The savings will be greatest in customer outlays for energy commodities, which are price volatile. However, outlays for the cost of the utility system may also be lowered, especially in the longer run when costly plant additions are avoided. Consider also that the North American system for producing, delivering, and consuming natural gas and electric power is one of the largest sources of greenhouse gases and other pollutants in the world. EE and investments in LDG facilities can help to contain the environmental damage.

It is widely acknowledged that decoupling cannot, by solving the “lost revenue” problem, by itself induce utilities to be aggressive proponents of CDM/DSM and customer-sited DG. For example, utilities need compensation for the cost of their CDM/DSM programs. Incentives to encourage large, efficient programs are also needed.

Some argue that a utility operating under decoupling still retains a long term incentive to promote system use to the extent that such growth may ultimately require plant additions. This is not a major problem for utilities that specialize in energy distribution since they do not own generating plants and their plant additions are not driven chiefly by average use. For vertically integrated electric utilities, however, growth in system use may create opportunities for new investment when transmission availability is limited and/or generation reserve margins are low. The incentive problem can be mitigated by competitive bidding for new generation and/or supplemental forms of compensation, for utility CDM/DSM programs, which are linked to avoiding plant additions.

The CDM/DSM incentive benefits of decoupling depend on the role that utilities are expected to play in CDM/DSM promotion. For example, they are reduced if CDM/DSM programs are undertaken by independent agencies rather than utilities.[16] However, utilities often have an influence on the budgets for these agencies. Moreover, utilities can promote efficient system use in various other ways that include

- rate design;
- other utility policies that affect LDG (*e.g.* net metering, feed in tariffs, & connections);
- support for government policies outside the regulatory arena that promote CDM/DSM goals (*e.g.* appliance efficiency standards, building codes, tax credits, and public funding of research and development);
- other promotional measures (*e.g.* advertising and other informational activities, facilitation of contact with EE and LDG service providers, sharing of information with vendors) that take advantage of a utility's reputation and close, long-lasting commercial relationship with customers; and
- CDM/DSM research and development by utilities.

A company can try hard with respect to one approach but undermine its effect on system use efficiency by not trying hard with respect to other approaches. As one example, the impact of utility CDM/DSM programs can be undermined by opposition to more stringent building codes. A decoupling method is therefore more effective to the extent that

[16] Such agencies have been established in Hawaii, Maine, New Jersey, New York, Ohio, Oregon, Vermont and Wisconsin.

it insulates earnings from all means of promoting clean energy. A decoupling method may be said to have a "wide scope" to the extent that it removes disincentives to pursue all means.

One gauge of the importance of the other avenues for promoting efficient system use is that some utilities have made commitments, in settlements, to unconventional CDM/DSM promotional activities as a condition for decoupling plan approval.

- Wisconsin Public Service agreed in its decoupling settlement with the Citizens Utility Board to specific steps to support the adoption and implementation of certain recommendations of the Governor's Global Warming Task Force addressing residential and commercial energy efficient building codes, state appliance efficiency standards, and nonregulated fuels efficiency and conservation.

- The Hawaii Clean Energy Initiative Agreement involves the three Hawaiian Electric companies and the state of Hawaii and its Division of Consumer Advocacy.[17] This forty-four page document contains commitments in thirty seven areas.

Another gauge of the importance of unconventional initiatives is that decoupling true up plans of some form are operational in five states (New York, New Jersey, Oregon, Wisconsin, and Vermont) in which most CDM/DSM programs are not administered by utilities.

The Connecticut Department of Public Utility Control stated, in a recent order approving a decoupling plan for United Illuminating, that it was approving the plan not because of its effect on the company's CDM program but for its effect on "areas where UI does not already receive incentives".[18] The Department goes on to explain that

> UI is still viewed as *the* energy provider by the general body of ratepayers. The Department believes that this will not change…Success in achieving Connecticut's energy policy goals requires that the Department take advantage of this relationship to promote the energy-related programs and policies that have been recently set in place.[19]

[17] "Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies", 2008.
[18] Connecticut DPUC, Decision, Docket 08-07-04, February 2009, p. 121.
[19] *Ibid*, pp. 121-122.

2.3.3 Earnings Attrition Relief

Other benefits of decoupling stem from its ability to afford utilities relief from slowing growth in average use between rate cases. Slowing growth can result from various circumstances that include aggressive CDM/DSM programs, high prices in energy commodity markets, increasingly stringent appliance efficiency standards and policies encouraging LDG. Irrespective of whether slowdowns occur due to the utility's actions, they can increase earnings attrition between rate cases. Decoupling can potentially make utilities whole for attrition from all these sources. In so doing, it promotes compensation between rate cases for a legitimate financial challenge and reduces the risk of undercompensation that might otherwise occur.

In understanding where and when decoupling is implemented, it is important to note that the attrition benefit of decoupling is greatest when average use in the important residential and small business sectors is declining. This may not occur until a high level of CDM/DSM effort is attained. If average use is growing due, for example, to rising incomes and/or falling prices for energy commodities, some forms of decoupling exacerbate earnings attrition by mitigating the effect of business conditions that, by increasing system use, slow unit cost growth. The result can be more frequent rate cases. Utilities have an incentive to oppose decoupling under these circumstances. To the extent that the attrition benefit of decoupling is important, we would then expect decoupling to be much more common when and where average use by small volume customers is flat or declining.

Decoupling true ups and SFV pricing can have the added effect of stabilizing revenue in the face of usage fluctuations that result, in the short run, from changes in weather, the business cycle, and miscellaneous other economic conditions. It is sometimes argued that these are risks that the utility is best positioned to absorb. However, utilities with high usage charges have earnings that are unusually sensitive to usage fluctuations. The reduced risk of demand fluctuations or secular decline in volume per customer can, in any event, lower the cost of obtaining funds in capital markets and this benefit can be shared with customers.[20] While it is possible in principle to decouple revenue only from the secular slowdown in

[20] Unpublished work by PEG Research has found that, out of fifteen decoupling plans for electric utilities surveyed, regulators made an explicit reduction to the target return on equity in five cases. The average reduction was fifteen basis points.

volume growth that results from utility CDM/DSM programs, this approach is reliant on complex and potentially controversial calculations.

While reducing revenue risks, decoupling by itself does not guarantee that a utility will recover its cost. In particular, a utility operating under a decoupling true up plan must still manage its cost to ensure that it is equal to or less than the allowed revenue. This can be challenging, especially when the firm is operating under a multiyear rate plan.

2.3.4 Efficient Regulation

Decoupling adds extra activities to the regulatory process but can nonetheless increase the efficiency of regulation on balance. The biggest benefit occurs when it permits a reduction in the frequency of rate cases by addressing an important source of financial attrition by other means. A single rate case can result in thousands of pages of testimony and discovery documents. A desire to reduce the frequency of rate cases is an important motivation for many other widely used trackers in utility ratemaking, including those for recovery of the costs of energy, pensions, and plant additions.

Decoupling true ups and SFV pricing can increase the efficiency of regulation in other ways as well. Both approaches reduce the importance of load forecasts in rate cases. This is a subject of considerable controversy in many proceedings. These approaches to decoupling also reduce the importance in regulation of the calculations required to accurately estimate the load impact of utility DSM programs, as we discuss further below.

The benefits of regulatory efficiency can be manifested in several ways. Regulatory cost may be reduced. Alternatively, cost savings may permit a redirection of resources to facilitate improved regulation in other areas. Economies in the regulatory process are especially welcome in a period of rapid change in utility business conditions, when a host of new regulatory issues may arise. The importance of regulatory economies also depends on the number of utilities that a commission regulates. For a commission with jurisdiction over dozens of utilities, regulatory cost savings can be decisive in deciding to embark upon decoupling.

Reducing the frequency of rate cases also strengthens a utility's incentives to contain cost, and senior managers can devote more time to the basic business of providing quality service at a reasonable cost. Cost performance should improve leading, in the long run, to lower rates for customers. Work by PEG Research personnel has revealed that increasing the frequency of rate cases from one to five years increases productivity performance by about 147 basis points annually in the long run.[21]

2.3.5 Potential Disadvantages of Decoupling

The debate on decoupling has also included some substantive criticisms. We address here some arguments that have not already been implicitly addressed in our discussion. Critics opine that decoupling true up plans can cause customers in one rate class to absorb some of the impact of demand downturns in another class. An example might be an increase in residential bills due to a downturn in industrial sector demand. Concern over this issue has prompted some regulators to use multiple revenue requirement baskets in decoupling true up plans.

Decoupling true up plans and SFV pricing erode incentives to offer services on market-responsive terms. While companies in competitive markets can suffer sharp reductions in business and big losses when their terms of service are not competitive, these approaches to decoupling eliminate the chance (already diminished by the monopoly character of utility service) that a utility would suffer financial harm from reduced system use. Quality can in principle suffer and customers may not be offered the special pricing packages that they need.[22]

Concern about the market responsiveness of rate and service offerings is greater to the extent that a utility serves customers whose demand is especially sensitive to the terms of service. A good example of such a customer is an industrial establishment that consumes large amounts of power and could develop self-generation capabilities or shift operations to other jurisdictions. Decoupling could in principle trigger the loss of existing large volume customers and a failure to attract new ones, to the detriment of the local economy. The importance of bypass risk varies greatly by service territory. In economies that are highly commercialized, the risk is generally contained. To the extent that there is a real concern about these issues, it can be mitigated by applying decoupling selectively to residential and small business customers and by developing service quality monitoring or incentive plans.

[21] See "Incentive Plan Design for Ontario's Gas Utilities", a presentation made by senior author Mark Newton Lowry in Toronto in November 2006.

[22] A related counterargument is that decoupling weakens the incentive of regulators to avoid policies that could, by reducing sales volumes, otherwise compromise utility finances.

Another concern about decoupling is that it may disincent utilities from encouraging uses of energy that can actually further environmental and other policy goals. Salient in this regard is the use of natural gas and electricity to power motor vehicles. This problem can be sidestepped by excluding sales for gas and electric vehicle use from the force of decoupling where these can be identified. However, this eliminates a potentially important force that can offset declines in average use and thereby mitigate the rate hikes that can otherwise be occasioned by decoupling true up plans.

2.4 Criteria for Decoupling Plan Selection

Assuming that some form of decoupling is deemed a useful addition to the regulatory system, criteria are needed to assess which of the three established approaches --- LRAMs, true up plans, and SFV pricing --- makes the most sense in a particular application. An approach to decoupling that is preferable in the context of one jurisdiction might not be preferable in another. Relevant criteria for choosing between decoupling approaches include the success of the approach in securing the main advantages of decoupling: efficient regulation, attrition relief, and the removal of financial disincentives for CDM/DSM. The other repercussions of a particular decoupling method should also be considered. We discuss each issue before drawing some tentative conclusions.

2.4.1 Efficient Regulation

Lost margins are difficult to estimate accurately. It is challenging to estimate the impact of conventional CDM/DSM programs in a world in which demand is affected by numerous other business conditions. The American Gas Association ("AGA") commented in a recent review of decoupling approaches that

> Lost margin trackers are complicated calculations that estimate the level of decreased distribution revenues caused by customer conservation. This requires an evaluation to distinguish between program-specific reductions in customer usage and other causes of reduced consumption. There is a great deal of uncertainty in the measurement of such reductions[23].

The estimates would be even more complicated in a case of less conventional utility initiatives such as support for more stringent appliance efficiency standards and building codes since it would be difficult to assess the impact of their support on the standards, much

[23] AGA, *Natural Gas Rate Roundup*, May 2009, p. 3.

less the effect of changes in the standards on system use. The Washington Utilities and Transportation Commission stated in its 1991 approval of a decoupling true up mechanism for Puget Sound Energy that "the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor."[24] This administrative cost problem helps to explain why LRAMs are generally applied only to utility-administered CDM/DSM programs. A related problem with LRAMs is that the dollars riding on the lost margin calculations can become quite large as the effects of CDM/DSM programs accumulate.

This having been said it should be noted that supplemental incentive mechanisms to encourage CDM/DSM performance using awards and/or penalties are increasingly popular in North American regulation. These are discussed further in Section 3.1.5. The impracticality of LRAMs is a less material consideration when CDM/DSM incentive mechanisms are operative if these mechanisms also require the estimation of volume and peak demand savings. Consider also that decoupling true up plans and SFV pricing can trigger more frequent rate cases, for utilities with rising average use trends, in the absence of RAMs that can raise rates for a variety of cost pressures and thereby make possible a rate case moratorium. Where the approval of such RAMs is problematic, LRAMs have the advantage of focusing on utility DSM/CDM programs. To the extent that they do, they can actually extend the period between rate cases.

As for the regulatory efficiency of the true up approach to decoupling, it adds revenue requirement adjustments to the regulatory agenda. Revenue reconciliations must be calculated, and a RAM is usually developed and instituted. However, the administrative cost of a decoupling true up is not much different than the cost of other widely used trackers, including purchased gas adjustment clauses. For trackers of both kinds, the appropriate revenue requirement adjustment must first be ascertained and then allocated to service classes and recovered through a change in rates. Moreover, in jurisdictions that use multiyear rate plans with attrition relief mechanisms, the development and operation of a RAM may not be an added cost.

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[24] Washington Utility and Transportation Commission, *3rd Supplemental Order* in Docket UE-901184-P Pg. 9

SFV pricing undoubtedly involves the lowest administrative cost amongst the three established decoupling approaches. Once SFV prices are established there is no need for supplemental annual rate adjustments of any kind to effect decoupling. SFV pricing also has the appeal, relative to decoupling true ups, of not necessitating the development and administration of a RAM. The latter advantage is not material, however, in a jurisdiction where multiyear rate plans are the norm since some kind of attrition relief mechanism is likely to be used anyways.

2.4.2 Earnings Attrition Relief

Since attrition relief is an important reason to adopt decoupling, we are naturally interested in which approach is likely to provide the most relief. LRAMs, with their high administrative cost, are deficient in this regard to the extent that there are declines in average use and these are due to factors other than conventional utility-administered CDM/DSM programs. SFV pricing and decoupling true ups do a better job in this context.

2.4.3 Removal of CDM/DSM Disincentives

LRAMs, decoupling true ups, and SFV pricing have similar effectiveness in removing disincentives to pursue conventional CDM/DSM programs. They do differ materially in their ability to remove disincentives for less conventional initiatives, where load impacts are harder to measure. All approaches can be wide scope in principle, but the LRAM approach has a decided administrative cost disadvantage.

SFV pricing can economically remove disincentives for a much broader range of initiatives than LRAMs. Its main shortcoming in this regard is that it reduces a utility's flexibility in the design of rates. This matters to the extent that SFV pricing does not promote efficient system use.

Utilities typically design the rates for their services even if they are not responsible for administering CDM/DSM programs. Rate design has a critically important impact on customer incentives for EE, peak load reduction, and LDG because it affects the payback period on investments (*e.g.* those for better insulation or rooftop solar facilities) that these initiatives involve. EE and LDG are generally encouraged by high volumetric charges. Time of use ("TOU") and other forms of peak load pricing --- for energy charges and base rates alike --- discourage *peak* system use and encourage development of customer-sited solar resources.[25]

It is sometimes argued that SFV pricing provides the right price signals for efficient utility system use, inasmuch as the cost of T&D systems is invariant with respect to system use in the short run. However, alternative rate designs are sometimes preferable if they do not subject the utility to undue risk. One issue is that peak demand may be an important long run driver of the cost of utility systems.[26] Peak demand is for this reason often used in cost of service studies to allocate the revenue requirement between customer classes. Usage charges can communicate to customers the especially high cost that results in the long run from peak system use. If AMI has been installed, this price signal can be sent via a demand charge rather than a volumetric charge.

Consider next that the production and consumption of natural gas and of power produced in fossil-fueled generating stations may involve environmental costs that, under current policymaking, are not fully reflected in the price of power. Customers are not encouraged to make the right decisions about energy purchases unless the totality of their volumetric charges reflects the full long run marginal cost to society of these purchases. When prices in energy commodity markets do not reflect the full environmental cost of energy production and use, base rates for T&D services can encourage the economically efficient use of energy by having material volumetric charges. This is a form of "social engineering" that may encourage efficient choices but will nonetheless be unappealing to some regulators.

Any tendency for rates that are designed to reflect long run marginal cost to over recover the cost of base rate inputs can be contained with low customer charges and/or inverted block rates.[27] The usefulness of inverted block rates is increased for customers that lack AMI since, in that event, they provide a useful approximation for time of use pricing. A

[25] The impact of peak load pricing on EE is less clear since it can result in usage charges that are below flat rates in most hours of use. Industrial customers in particular may be able to shift loads to off peak hours and purchase more energy on balance.
[26] This is an empirical issue that is, in principle, amenable to statistical cost research. However, the requisite data for such research are not readily available, and progress in measuring the relative impacts of peak demand and the number of customers served on distribution cost has been slow.
[27] For more information on the impact that inverted block rates can have on clean energy see Ren Orans and C.K. Woo, "Inclining for the Climate: GHG Reduction Via Residential Electricity Ratemaking", *Public Utilities Fortnightly*, May 2009.

central rationale is that the incremental volumes consumed by a customer are increasingly likely to occur at the system peak. For example, a gas customer's consumption may reach the highest consumption block only in the winter.

The inefficiency of SFV pricing has been argued by some prominent advisors to regulatory commissions. For example, the Regulatory Assistance Project ("RAP") states in a 2008 report on decoupling to Minnesota's PUC that

> a zero or minimum customer charge allows the bulk of a utility's 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.[28]

The National Regulatory Research Institute (NRRI) writes that "the problem with SFV is that it reduces the variable charge to short-term variable cost, which is likely to be lower than the economically efficient level of long-term marginal cost, leading to overconsumption."[29]

This discussion suggests that SFV pricing may in some instances constrain the ability of utilities to use rate design to advance energy efficiency and environmental policy goals. To the extent that this is true, SFV pricing also reduces the opportunities for vendors of CDM/DSM products and services to make their full potential contribution to the energy economy. The problem is aggravated when customers lack AMI so that all base rate revenue must be gathered, under SFV pricing, through customer charges. While it is sometimes argued that energy commodity prices provide sufficient incentive to reduce energy purchases, prices for these commodities do not yet properly reflect the cost of environmental damage in North American markets and, in any event, are currently well below the peak levels of recent years.

The natural gas pipeline industry of the United States provides an illustration of how SFV pricing for recovery of a utility's fixed costs materially promotes system use despite volumetric charges for energy commodities. The Federal Energy Regulatory Commission ("FERC") has for decades regulated the interstate natural gas pipeline industry of the United States. The Commission had long viewed cuts in pipeline volumetric charges as a means to increase the competitiveness of natural gas vis a vis coal. In adopting SFV pricing for all

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[28] Wayne Shirley, Jim Lazar, and Frederick Weston, "Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission", Regulatory Assistance Project, June 2008, p. 18.
[29] David Magnus Boonin, "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements", National Regulatory Research Institute, 2008.

pipelines in 1992, there is little doubt that they contemplated further gains in system use. They stated that "the Commission's adoption of SFV should *maximize pipeline throughput* over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change" [italics added].[30] SFV pricing has contributed to the growth of gas-fired generation that has since been experienced in regions of the U.S. that are distant from natural gas fields.

Having established that rate designs with material demand and/or volumetric charges may be desirable for T&D services, the point should be made that such rate designs are facilitated by decoupling true ups. Experimental rate designs can increase revenue risk. Inverted block rates, for instance, encourage EE and LDG and thereby discourage system use. Moreover, they enhance the sensitivity of revenue to fluctuations in demand drivers such as weather, fossil fuel prices, and recessions. The RAP states in its report to Minnesota's PUC that

> Revenue stability needs of the company can conflict with principles of cost causation as they relate to customers…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 [Pacific Gas & Electric ("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.[31]

As for peak load pricing, this has an impact on base rate revenue that is hard to predict, especially when first introduced. Peak load pricing also doesn't achieve full decoupling of earnings from usage charges. A utility can benefit from peak load pricing to the extent that its customers have flexible load profiles because it can facilitate the retention and even the expansion of such loads. However, these are typically large-volume customers,

[30] Order No. 636 Final Rule, p. 129, April 1992.
[31] Shirley, *et al*, *op cit*, p. 17.

who contribute less to the base rate revenues of energy distributors than they do to those of vertically integrated utilities.

It is important to note in this regard that containment of the risk of rate designs with high volumetric and demand charges will be greater to the extent that earnings are decoupled with respect to *all* sources of demand volatility, including recessions and weather fluctuations. This benefit of *full* decoupling true ups is not widely recognized. The target ROE of a utility may need to be raised in the absence of full decoupling true ups if it is engaged in extensive rate design experimentation.

The importance of this benefit of decoupling true up plans should be reflected in a tendency of utilities operating under these plans to employ experimental rate designs. We discuss experience in California and Oregon in our case studies in Section 3.2 below. Here are some additional examples.

- Idaho Power is the largest vertically integrated utility in Idaho. Its decoupling true up plan covers only residential and small commercial customers. In 2009, the Commission approved a three tier, year around inverted block rate structure for most residential customers.[32] The Commission also approved year round inverted block rates for the small general service customers covered by decoupling. Staff identified these tiered rates as a "reasonable surrogate for time of use rates that send customers a message to use energy efficiently."[33]
- The decoupling true up plan of Wisconsin Public Service covers residential and most commercial customers. A reduction in residential customer charges (*e.g.* from $8.40 to $5.70 for single phase service) was part of the Company's settlement with the Citizens Utility Board. The decoupling plan also includes the development and implementation of three community based pilot programs that include "innovative rate offerings that increase opportunities for customers to use energy more efficiently."[34]
- The Hawaiian Clean Energy Initiative Agreement commits the HECO Companies to implement an inverted block rate for residential customers.

[32] Most residential customers previously faced a two tier increasing block rate structure with a very gradual inversion in the summertime.
[33] Idaho Public Utilities Commission, Order No. 30722 in Case IPC-E-08-10. January 30, 2009. p.39.
[34] Second Revised Energy Efficiency Stipulation of Wisconsin Public Service Corporation and Citizens Utility Board in Docket 6690-UR-119. Filed October 15, 2008. p.6

2.4.4 OTHER REPERCUSSIONS OF DECOUPLING

Rate and Revenue Stability

The issue of rate and revenue stability is often discussed in debates about decoupling but is not widely understood. SFV pricing stabilizes base rate revenue to the extent that it increases the recovery of cost using fixed charges. Decoupling true up plans stabilize base rate revenue insofar as they constrain it to track the gradual growth of the revenue requirement. In each case, customer bills are also stabilized.[35] This is a matter of *mutual* risk reduction and not of a *shifting* of risk to the customer from the utility. To understand the distinction, consider that the implementation of a variance account for the cost of energy commodity procurement reduces the risk of the utility but increases customer risk. This does involve a transfer of risk.

SFV pricing is more effective than decoupling true ups at stabilizing customer bills. The difference between the approaches is even larger with regard to *rate* stability. SFV pricing achieves decoupling with stable rates. In the case of true up plans, greater stability of bills comes at the expense of less stable rates. A revenue shortfall in one year, for instance, requires a special rate increase in the next year. However, experience has shown that this problem is not unmanageable. A study by Eto, Stoft, and Belden of the first decade of California decoupling true up plans reveals that price volatility was generally not pronounced.[36] In New York, the reconciliations ranged from a 0.2% decrease to a 2% increase but some reconciliations were capped.[37] Another study, prepared for the National Resources Defense Council, has reached the same finding for more recent decoupling plans.[38] In the latter study, rate adjustments were reported to be typically less than 2% and only rarely in excess of 5%.[39] Rate adjustments produced by purchased gas adjustment and fuel and purchased power adjustment clauses tended to be much larger. The study also found

[35] Decoupling provides further stability to customer expenditures to the extent that it leads to lower purchases of price volatile energy commodities.
[36] Joseph Eto, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling*, Lawrence Berkeley Laboratory paper LBL-34555 UC-350, 1994.
[37] James T. Gallagher, "Revenue Decoupling: New York's Experience and Future Directions", NARUC 2007 Summer Committee Meetings, July 2007.
[38] Pamela Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review", June 2009.
[39] *Ibid*.

that adjustments were positive nearly as often as they were negative. Weather tended to be the primary cause of rate adjustments.

The rate volatility problem is nonetheless of concern to some regulators. Rate adjustment caps, discussed in Section 2.2.2, can be used to temper this problem. Rate increases resulting from decoupling can be especially unwelcome during a prolonged recession since rates will likely rise in the second year of the recession even though the economy has not yet rebounded. While this is a disadvantage of the decoupling true up, it should be recognized that rates can rise in the later years of a prolonged recession under traditional regulation as well.

Rate Gradualism and Fairness

SFV pricing can raise issues of rate fairness if the revenue requirement for residential and small commercial customers is recovered through high customer charges that are the same for all customers in the class. Assuming that larger volume customers in these service classes do not have unusually high load factors, they should pay *more* for peak system use and for damage to the environment from energy production and consumption than smaller volume customers such as apartment dwellers. This problem can be remedied by AMI since, in that event, customers with higher peak demands can have higher bills. However, this approach would not achieve full decoupling. This problem can also be ameliorated by having customer charges vary in some rough fashion with historical consumption, as we discuss in Section 2.2.3.

Another problem with SFV pricing is that rapid implementation can produce sharp increases in bills for small-volume customers. An example of this from Ohio is discussed in Section 3.2.5. Commissions committed to the principle of rate change gradualism may phase in higher customer charges gradually but this also means a gradual phase in of decoupling.

The problems of high bills for small customers and weak incentives for conservation can also be alleviated by the addition of a revenue neutral energy efficiency adjustment to the SFV pricing scheme.[40] The idea of such a system, which is sometimes called a "feebate" system, is to charge a premium to each customer group for any power consumption in excess of a certain volumetric threshold. The dollars thus gathered would be transferred to customers (hence the notion of revenue neutrality) with power consumption below a certain

[40] For more on this imaginative approach see David Magnus Boonin (2008) *op cit*.

threshold. The extra fee per dollar of excess consumption could be set so that the effective total charge per unit purchased equals an estimate of the long run marginal cost of a kWh to society. This concept has not to date been implemented for an energy utility to our knowledge.

Weakened Customer Conservation Incentives

It is sometimes argued that decoupling weakens customer incentives to pursue conservation. This argument is true with respect to SFV pricing, with its low usage charges but not with respect to LRAMs or decoupling true ups. With the latter two approaches, customers *as a group* must pay for the lost margins no matter how much they use the system but *individual* customers can reduce their distribution bills by conserving. The upward drift in rates that results from these decoupling approaches incents individual customers to conserve more.

2.4.5 Conclusions

This discussion suggests that the preferred approach to decoupling depends on the particular circumstances in a jurisdiction. LRAMs are comparatively advantageous to the extent that

- the number of regulated utilities is small;
- utilities are administering conventional CDM/DSM programs;
- CDM/DSM programs account for most of the slowdown in volume growth that is occurring between rate cases;
- other business conditions, such as rising incomes, are causing average use to *increase*; and
- there are limited opportunities for utilities to promote CDM/DSM goals by unconventional means.

Decoupling true up plans and SFV pricing have a comparative advantage over LRAMs when the opposite conditions hold. For example, they may be favored when regulators have jurisdiction over numerous utilities, average use is declining for reasons other than utility-administered programs, and/or there are multiple avenues, in addition to conventional CDM/DSM programs, by which utilities can influence energy efficiency.

Of the latter two options, SFV pricing is less costly to administer and also produces more stable prices. SFV may therefore be favored by regulators who put a heavy premium on regulatory simplicity and eschew experimental rate designs. However, SFV pricing can raise bills for small volume customers and limits the opportunity for the design of base rates to support broader energy efficiency, peak load management, and distributed generation goals.

The pricing advantages of the true up approach to decoupling are greater to the extent that the following conditions hold.

- Prices in the markets for the relevant energy commodities do not reflect the cost of correlative environmental damage and this damage is substantial.
- The cost of the utility system depends materially on system use, especially in the shorter run (as when generation and transmission capacity are in short supply).
- Customers do not have AMI, so that inverted block rates may be useful in discouraging peak demand.

The Connecticut DPUC recently recognized the advantages of the true up approach in choosing it over SFV pricing for United Illuminating despite the Department's expression of interest in the latter in an earlier proceeding.

> UI will be assured of its revenue recovery. As a result, UI should be indifferent as to whether its revenues are collected through fixed charges, energy-based charges, or a combination of these rates. UI's proposal relies on a kWh-based decoupling mechanism instead of increases in fixed costs. This allows UI to maintain higher kWh charges which will provide customers with energy-based price signals…This in turn eliminates the Department's concern regarding the bill impacts associated with fixed cost recovery on low use customers. This also addresses the objections raised by the OCC and Environment Northeast as to the anticonservation potential associated with fixed cost recovery of distribution revenues.[41]

[41] Connecticut DPUC, *op cit*, p. 123.

3. REVENUE DECOUPLING EXPERIENCE

In this chapter of the report we review the accumulating experience with different approaches to revenue decoupling in North America. In Section 3.1 we present a brief history of each of the three approaches. There follow in the next section five noteworthy case studies on decoupling experiments. We report in Section 3.3 on some rankings of the effectiveness of CDM/DSM programs. There are brief concluding remarks.

3.1 Revenue Decoupling Precedents

3.1.1 Background

Several basic facts about CDM/DSM programs in the United States are relevant to a discussion of decoupling experience there. Note first that interest in CDM/DSM is by no means uniform across the states. A recent survey by the AGA identified only 32 states in which distributors managed DSM programs.[42] There is, similarly, a large number of states that have no electric CDM programs.

Ten states are identified in a 2006 study by Kushler, York, and Witte of the American Council for an Energy Efficient Economy ("ACEEE") as offering electric utilities compensation for CDM program expenses but not for lost margins.[43] The AGA study identifies nine states which have the same policy for gas utilities. Our interest, then, is in the approaches to decoupling in the residual states that have notable CDM/DSM programs and some form of decoupling.

Independent administrators provide most or all CDM/DSM programs in at least eight of the residual states. These states are Hawaii, Maine, New Jersey, New York, Ohio, Oregon, Wisconsin, and Vermont. The LRAM approach to decoupling is not applicable in these states and this has materially limited its popularity. If there is an interest in decoupling, the choice in these states is instead between true up plans and SFV pricing.

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[42] American Gas Association, *Natural Gas Rate Round-Up*, May 2009.
[43] These states were Colorado, Florida, Idaho, Illinois, Iowa, Montana, Texas, Utah, and Washington. See Martin Kushler, Dan York, and Patti Witte, *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives",* Report Number U061, American Council for an Energy-Efficient Economy, Washington DC, 2006. p. 40.

3.1.2 DECOUPLING TRUE UP PLANS

States that have tried decoupling true up plans are indicated on the map in Figure 2. The full set of decoupling true up plan precedents is detailed in Table 1. We provide here an overview of the precedents and discuss some in greater detail in the case studies.

Early Experiments

The bulk of North American experience with the true up approach to decoupling has occurred in California. True up plans began there in the gas industry in the late 1970s and expanded to electric utilities in the early 1980s. As discussed further in Section 3.2.1, the California Public Utilities Commission ("PUC") suspended plans for most electric utilities in the mid 1990s. A resumption of decoupling true up plans was required by a 2001 state statute.

True up plans were adopted to regulate several electric utilities in New York and the largest electric utilities in Maine and Washington state in the early 1990s.[44] Experiments were also conducted in the nineties by an electric utility in Florida (Florida Power) and by the largest electric utilities in Montana and Oregon.

Kushler, York, and Witte discuss the impact of the decoupling mechanism in Washington.[45] They state that "implementation of this decoupling mechanism played a critical part in changing the role of energy efficiency and conservation programs within Puget Sound Energy. In the first two years there were dramatic improvements in energy efficiency program performance." In extending the program for another three years in 1993, the Washington regulator observed that the decoupling mechanism "has achieved its primary goal – the removal of disincentives to conservation investment. Puget has developed a distinguished reputation because of its conservation programs and is now a national leader in this area."[46]

Decoupling true up plans were suspended after a few years in all of these states. In New York, electric utility CDM programs were largely discontinued by the Commission at the time of the power market restructuring. In Maine and Washington, suspension was due, in whole or in part, to higher rates but the rate hikes were in each case attributable to multiple

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[44] The early innovators included Orange & Rockland Utilities, Niagara Mohawk Power, Consolidated Edison, Puget Power, & Central Maine Power.
[45] Martin Kushler *et al, op cit*, p. 40.
[46] WUTC, 11th Supplemental Order, Sept. 21 1993.

Table 1

Summary of True Up Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Canada					
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	Pacific Northern Gas	Gas	2003-open	RPC Freeze	N/A
BC	BC Gas Utility	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Gas Utility	Gas	1998-2000	Hybrid	Order G-85-97
BC	BC Gas Utility	Gas	1996-1997	Hybrid	N/A
BC	BC Gas Utility	Gas	1994-1995	Hybrid	Order G-59-94
ON	Enbridge Gas Distribution	Gas	2008-2012	Inflation Indexing	Docket EB-2007-0615
ON	Union Gas	Gas	2008-2012	Price Cap	Docket EB-2007-0606
United States					
AR	CenterPoint Energy	Gas	2008-2010	RPC Freeze	Docket 07-081-TF
AR	Arkansas Oklahoma Gas	Gas	2007-2011	RPC Freeze	Docket 07-026-U
AR	Arkansas Western	Gas	2007-2010	RPC Freeze	Docket 06-124-U
CA	Southern California Edison	Electric	2009-2011	All Forecast ("Stairstep")	Decision 09-03-025
CA	Southern California Gas	Gas	2008-2011	All Forecast ("Stairstep")	Decision 08-07-046
CA	San Diego Gas & Electric	Electric & Gas	2008-2011	All Forecast ("Stairstep")	Decision 08-07-046
CA	Pacific Gas & Electric	Electric & Gas	2007-2010	All Forecast ("Stairstep")	Decision 07-03-044
CA	PacifiCorp	Electric	2007-2010	Inflation Indexing	Decision 06-12-011
CA	San Diego Gas & Electric	Gas & Elec	2005-2007	Inflation Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	2005-2007	Inflation Indexing	Decision 05-03-025
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Pacific Gas & Electric	Gas & Elec Dx/Gen	2004-2006	Inflation Indexing	Decision 04-05-055
CA	Southern California Edison	Electric	2002-2003	Inflation Indexing	Decision 02-04-055
CA	Southern California Gas	Gas	1998-2002	Inflation Indexing	Decision 97-07-054
CA	San Diego Gas & Electric	Electric & Gas	1994-1999	Hybrid	Decision 94-08-023
CA	Pacific Gas & Electric	Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	San Diego Gas & Electric	Electric & Gas	1986-1988	Hybrid	Decision 85-12-108
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	PacifiCorp	Electric	1984-1985	All Forecast ("Stairstep")	Decision 89-09-034
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	San Diego Gas & Electric	Electric & Gas	1982-1983	Hybrid	Decision 93892
CA	Pacific Gas & Electric	Electric	1982-1983	Hybrid	Decision 93887
CA	Southern California Gas	Gas	1981-1982	All Forecast ("Stairstep")	Decision 92497
CA	Southern California Gas	Gas	1979-1980	All Forecast ("Stairstep")	Decision 89710
CA	Pacific Gas & Electric	Gas	1978-1985	Inflation Indexing	Decision 89316
CA	San Diego Gas & Electric	Gas	1978-1981	Hybrid	Decision 88835
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CO	Public Service Company of Colorado	Gas	2008-2010	RPC Freeze	Decision C07-0568
CT	United Illuminating	Electric	2009-2010	All Forecast ("Stairstep")	Docket No. 08-07-04
DC	Potomac Electric Power	Electric	2010-open	RPC Freeze	Order 15556
FL	Florida Power Corporation	Electric	1995-1997	RPC Freeze	Docket 930444
ID	Idaho Power	Electric	2007-2010	RPC Freeze	Case No. IPC-E-08-04
IL	North Shore Gas	Gas	2008-open	RPC Freeze	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	RPC Freeze	Case 07-0242
IN	Vectren Energy	Gas	2007-open	RPC Freeze	Cause No. 43046
IN	Vectren Southern Indiana	Gas	2007-open	RPC Freeze	Cause No. 43046
IN	Citizens Gas	Gas	2007-2011	RPC Freeze	Cause No. 42767
MA	Massachusetts Electric	Electric	2010-open	Hybrid	DPU 09-39
MA	Bay State Gas	Gas	2009-open	Hybrid	DPU 09-30

Table 1 (cont'd)

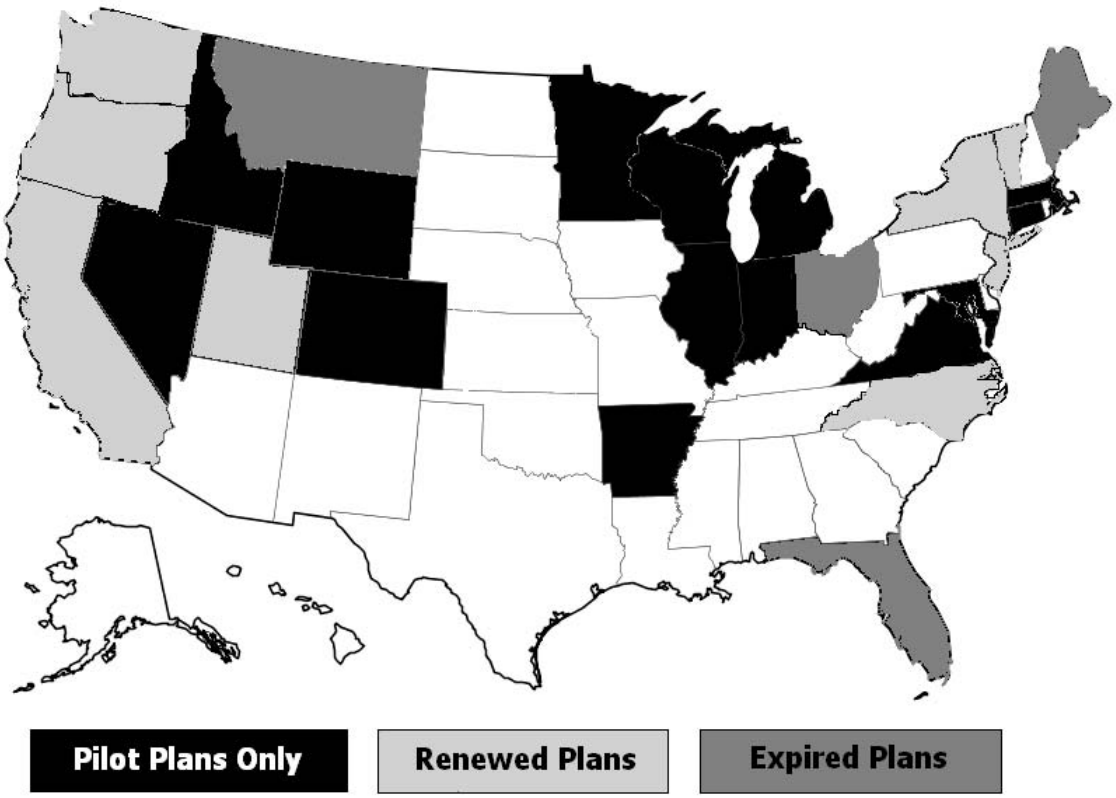
Jurisdication	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
MD	Baltimore Gas & Electric	Electric	2008-open	RPC Freeze	N/A
MD	Delmarva Power & Light	Electric	2007-open	RPC Freeze	Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	RPC Freeze	Order No. 81517
MD	Washington Gas Light	Gas	2005-2008	RPC Freeze	Order No. 80130
MD	Baltimore Gas & Electric	Gas	1998-open	RPC Freeze	Case No. 8780
ME	Central Maine Power	Electric	1991-1993	RPC Freeze	Docket No. 90-085
MI	Consumers Energy	Electric	2009-2012	RPC Freeze	C-U-15986
MN	CenterPoint Energy	Gas	2010-2013	RPC Freeze	GR-08-1075
MT	Montana Power Company	Electric	1994-1998	RPC Freeze	Docket No. 93.6.24
NC	Public Service Co of NC	Gas	2008-open	RPC Freeze	Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2008-open	RPC Freeze	Docket No. G-9, Sub 550
NC	Piedmont Natural Gas	Gas	2005-2008	RPC Freeze	Docket G-44 Sub 15
NJ	New Jersey Gas Natural	Gas	2007-2010	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	RPC Freeze	Docket GR05121019
NV	Southwest Gas	Gas	2009-open	RPC Freeze	D-09-04003
NY	Orange & Rockland Utilities	Gas	2009-2012	All Forecast ("Stairstep")	Case 08-G-1398
NY	Niagara Mohawk	Gas	2009-2011	RPC Freeze	Case 08-G-0609
NY	National Fuel Gas	Gas	2008-open	RPC Freeze	Case 07-G-0141
NY	Central Hudson G&E	Electric	2008-open	No RAM	Case 08-E-0887
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Orange & Rockland Utilities	Electric	2008-2011	All Forecast ("Stairstep")	Case 07-E-0949
NY	Consolidated Edison	Gas	2007-2010	All Forecast ("Stairstep")	Case 06-G-1332
NY	Rochester Gas & Electric	Electric	1993-1996	All Forecast ("Stairstep")	Opinion No. 93-19
NY	New York State Electric & Gas	Electric	1993-1995	All Forecast ("Stairstep")	Opinion No. 93-22
NY	Consolidated Edison	Electric	1992-1995	All Forecast ("Stairstep")	Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	All Forecast ("Stairstep")	Opinion No. 92-8
NY	Orange & Rockland Utilities	Electric	1991-1993	All Forecast ("Stairstep")	Case 89-E-175
NY	Niagara Mohawk	Electric	1990-1992	All Forecast ("Stairstep")	Case 94-E-0098
OH	Vectren Energy	Gas	2007-2009	RPC Freeze	Case 05-1444-GA-UNC
OR	Northwest Natural Gas	Gas	2009-2012	RPC Freeze	Order No. 07-426
OR	Portland General Electric	Electric	2009-2010	RPC Freeze	Order No. 09-020
OR	Cascade Natural Gas	Gas	2006-2010	RPC Freeze	Order No. 06-191
OR	Northwest Natural Gas	Gas	2006-2009	RPC Freeze	Order No. 05-934
OR	Northwest Natural Gas	Gas	2002-2006	RPC Freeze	Order No. 02-634
OR	PacifiCorp	Electric	1998-2001	Inflation Indexing	Order No. 98-191
OR	Portland General Electric	Electric	1995-1996	All Forecast ("Stairstep")	Order No. 95-0322
UT	Questar Gas	Gas	2006-2010	RPC Freeze	Docket No. 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	RPC Freeze	Case No. PUE-2008-00060
VT	Central Vermont Public Service	Electric	2008-2011	Inflation Indexing	D-7336
VT	Green Mountain Power	Electric	2007-2010	All Forecast ("Stairstep")	Docket No. 7176
VT	Vermont Gas Systems	Gas	2006-2011	Hybrid	Docket No. 7109
WA	Avista	Gas	2007-2009	RPC Freeze	Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	RPC Freeze	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	RPC Freeze	Docket UE-901184-P
WI	Wisconsin Public Service	Electric	2009-2012	RPC Freeze	D-6690-UR-119
WY	Questar Gas	Gas	2009-2012	RPC Freeze	Docket 30010-94-GR-08

Table 1 (cont'd)

Jurisdication	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Australia					
Federal	ElectraNet	Power	2008-2012	Hybrid	Final Decision (11 April 2008)
Federal	Powerlink	Power	2007-2011	Hybrid	Final Decision (14 June 2007)
Federal	EnergyAustralia	Power	2004-2009	Hybrid	File No: S2004/138
Federal	TransGrid	Power	2004-2009	Hybrid	File No: M2003/287
Federal	ElectraNet	Power	2003-2007	Hybrid	File No: C2001/1094
Federal	Powerlink	Power	2002-2006	Hybrid	File No: 2000/659
Federal	EnergyAustralia	Power	1999-2004	Hybrid	File No: CG98/118
Federal	TransGrid	Power	1999-2004	Hybrid	File No: CG98/118
Federal	Snowy Mountains	Power	1999-2004	Hybrid	File No: C1999/62
New South Wales	Energy Australia	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Integral Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Advance Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Great Southern Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Northern Electric	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Australian Inland Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
Tasmania	Transcend Networks	Power Transmission	2004-2008	Hybrid	File No: C2001/1100
Victoria	SPI PowerNet	Power Transmission	2003-2008	Hybrid	File No: C2001/1093
Victoria	VENCorp	Power	2003-2007	Hybrid	File No: C2001/1093

Figure 2: U.S. Decoupling Precedents by State:

True up Plans



causes.[47] For example, in Washington the decoupling mechanism was combined with a power cost adjustment mechanism. The suspension in Washington was also due to an expected power market restructuring that never transpired. Puget's CDM programs were scaled back substantially. The complexity of the decoupling mechanisms was a stated reason for the suspension of the decoupling mechanism in Montana, which involved statistical normalization of sales volumes.[48] Florida Power did not request renewal of its residential decoupling true up plan, complaining to the commission in a 1998 letter that it was too complex, inconsistent with the company's market orientation, and provided no positive incentive to pursue CDM.

[47] Maine's experience with decoupling is discussed further in Section 3.2.3.
[48] See, for example, Commission Order No. 5858a in Utility Division docket number 95.6.27, September 1995.

Gas Takes the Lead

Since the end of the first wave of decoupling experimentation, decoupling true up plans have been more popular in the gas distribution industry than in the electric power industry. This reflects, in the main, the more pervasive declines in average use that gas distributors face. The causes of declining average use by small-volume gas customers have been discussed in several reports.[49] Noted drivers include high gas prices, energy efficiency improvements in new construction, improvements in the insulation of older homes, the replacement of older furnaces with more efficient units, reduced winter weather severity, and utility DSM programs.

Lowry, Fenrick, and Getachew discussed the problem of declining average use in the U.S. gas utility industry in a 2006 paper.[50] They reported that from 1997 to 2002, the weather normalized average use of gas in the United States declined by 1.53% for residential customers and exceeded 2% in several states. The decline in average use by commercial customers averaged 1.35%. The average U.S. home uses about one third less gas than it did a quarter century ago.[51]

The phenomenon is by no means confined to the United States. A Toronto consulting firm, IndEco Strategic Consulting, prepared a report for the Canadian Gas Association in 2006.[52] They note in the report that declines in average use are widespread in Canada's gas distribution industry. In the residential sector, for example, average use declined by 1.1% annually on average 1980-2001.

In contrast to these gas industry trends, PEG Research has estimated in unpublished research that, for a sample of 71 U.S. electric utilities from 2003 to 2008, weather-normalized deliveries per residential customer averaged 0.23% annual *growth*.[53] The average use of residential customers fell for only 28 of these companies. Over the same period, weather-normalized deliveries per commercial customer averaged a slight 0.04% annual growth. Thirty five of these companies had negative trends. Under these conditions,

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[49] See, for example, AGA, *Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020,* September 2004.
[50] Mark Newton Lowry, Lullit Getachew, and Steven Fenrick, "Regulation of Gas Distributors with Declining Use per Customer", USAEE *Dialogue*, August 2006, pp. 17-27.
[51] AGA May 2009, *op cit* p. 6.
[52] IndEco Strategic Consulting, "Declining Average Customer Use of Natural Gas: Issues and Options", December 2006.
[53] Weather-adjusted deliveries per commercial customer averaged 0.73% annual *growth*.

most electric utilities in the United States are not incented to propose either decoupling true up plans or SFV pricing.

Outside of California, the early adopters of gas decoupling true up plans included Baltimore Gas and Electric, BC Gas (d/b/a Terasen Gas), and Northwest Natural Gas. Approvals of decoupling true up plans for gas utilities surged after 2005, spurred in part by high gas prices. Plans have now been approved for 34 North American gas utilities. Several other gas utilities have had decoupling true up proposals rejected.[54] Some LDCs that operate under decoupling do not have large-scale DSM programs. Due in part to the greater price sensitivity of larger volume gas users in this industry, the decoupling plans of many gas distributors apply only to residential and commercial customers.

The Electric Renaissance

A resurgence of interest in decoupling true up plans for electric utilities began in 2007. This has reflected, in part, the general renewal of interest in CDM that occurred after industry restructuring was completed and it became apparent that marketers would play a small role in serving small-volume customers. There are currently nineteen plans operative in the industry involving utilities in California, Connecticut, the District of Columbia, Hawaii, Idaho, Maryland, Massachusetts, Michigan, Oregon, New York, Vermont, and Wisconsin. The eventual implementation of decoupling true up plans for all energy distributors is now required by law or commission mandate in three of the leading CDM states: California, Massachusetts, and New York.

Summary

In totality, the following twenty-five states, the District of Columbia, and two Canadian provinces have tried decoupling true up plans for at least one gas or electric utility.

US: CA, CO, CT, DC, ID, HI, IL, IN, FL, MD, MA, ME, MI, MN, MT, NC, NJ, NY, NV, OH, OR, UT, VT, WA, WI, WY

Canada: ONT, BC

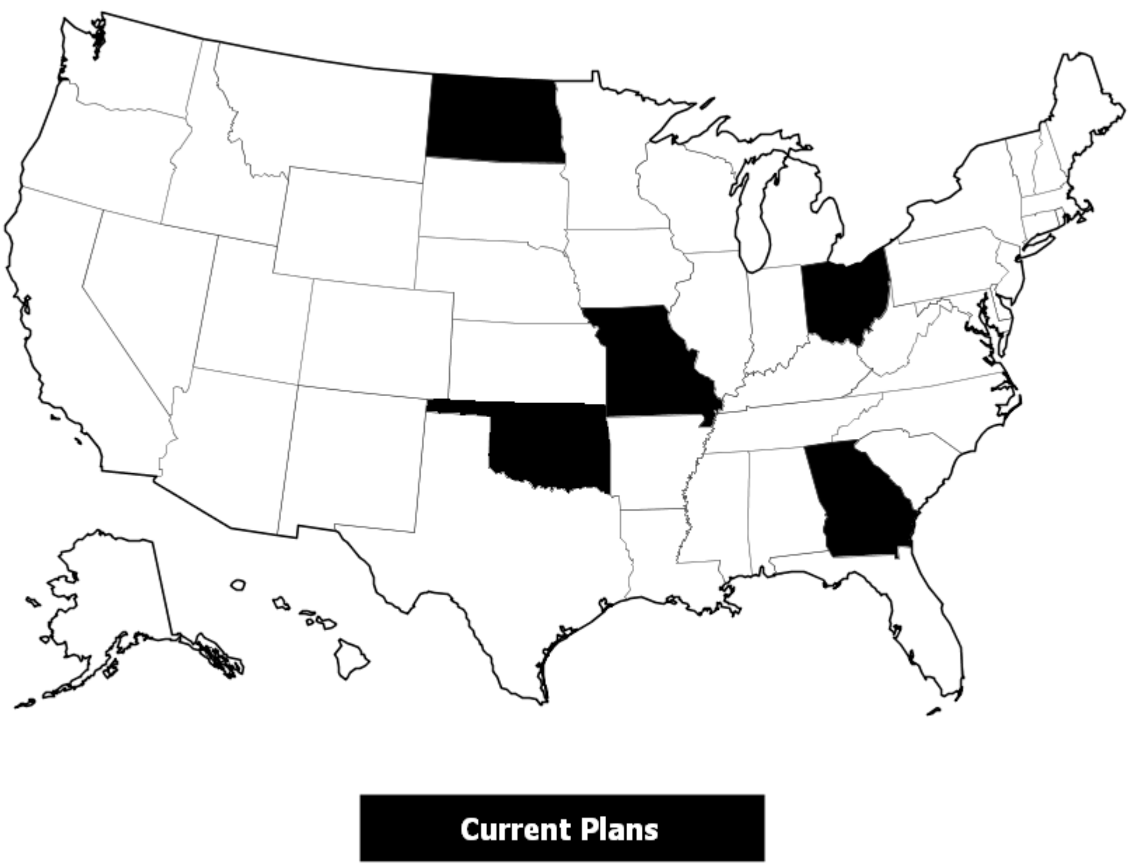
Table 1 shows that eight states (California, Maryland, North Carolina, New Jersey, New York, Oregon, Vermont, and Washington) which have experimented with decoupling true up plans have gone on to approve other such plans. Four other states (Florida, Maine, Montana, and Ohio) have not.

[54] Examples include NICOR Gas, the Ameren utilities in Illinois, and National Grid in Rhode Island.

3.1.3 SFV PRICING

SFV pricing was noted in Section 2.2.3 to have been used on a large scale by the Federal Energy Regulatory Commission ("FERC") since the early 1990s to regulate natural gas pipelines. Precedents for the use of SFV in *retail* ratemaking have to date been confined to the gas distribution industry. The states that have adopted SFV pricing (Georgia, Missouri, North Dakota, Ohio, and Oklahoma) for retail services are indicated on the map in Figure 3. Some details of the pricing plans are reported in Table 2.

Figure 3: U.S. Decoupling Precedents by State:
SFV Pricing



Ohio is noteworthy for having recently switched from the true up approach to decoupling to the SFV approach. In addition, several states have in recent years made noteworthy steps in the direction of SFV by redesigning energy distribution rates for small volume customers to raise customer charges and lower volumetric charges substantially. A

Table 2

APPROVED PRECEDENTS FOR RETAIL STRAIGHT-FIXED VARIABLE RATES

Jurisdiction	Company Name	Services	Years in Place	Case Reference
GA	Altanta Gas Light	Gas	1999-open	Docket No. 8390-U
MO	Atmos Energy	Gas	2007-open	Case GR-2006-0387
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MO	Laclede Gas Company	Gas	2002-open	Case GR-2006-0422
ND	Xcel Energy	Gas	2005-open	Case Pu-04-578
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Ccase 07-1080-GA-AIR
OK	Oklahoma Natural Gas	Gas	2009-open	Case 572180

good example is a recent decision by the Illinois Commerce Commission to raise customer charges for the gas distribution services of the three Ameren Illinois utilities.

3.1.4 LRAMS

LRAMs were used in several states (*e.g.* MA and MN) in the early 1990s but this approach to decoupling no longer predominates in the United States. Kushler, York, and Witte report in their 2006 study that

> Mechanisms to directly reimburse for specific program lost revenues have fallen from favor. Several states have had such mechanisms in the past but these practices have generally ended. 'Lost revenue" recovery remains a concern to utilities and their regulators, but we observed that commissions appear to be addressing this through decoupling mechanisms and/or performance incentives". [55]

In Connecticut, a filing for lost margins due to *energy efficiency* requires a showing that earnings are below the allowed ROR. Lost margins can also be recovered in Connecticut for load response and LDG initiatives in a region of the state which has experienced capacity shortages. LRAMs are also part of the "Save a Watt" CDM regulatory provisions for Duke Energy in the states where it provides retail electric services. The AGA reports that five states used lost margin trackers for gas utilities at the end of 2007.[56] These states are Connecticut, Kentucky, Massachusetts, New York, and Oregon. Four of these states now also have decoupling true-up plans.

3.1.5 CDM/DSM Performance Incentives

A review of decoupling should not ignore the proliferation of financial incentives for good utility CDM/DSM performance. Some CDM/DSM performance mechanisms offer awards that depend on variances between benchmarks and a utility's actual values for key performance indicators. Others involve a rate of return on the capitalized expenses. Still others give utilities a share of the estimated net program benefits.

A 2008 ACEEE study found that the following nineteen states currently offer electric utilities incentive mechanisms for good CDM performance:

[55] Kushler, York, and Witte (2006) *op cit.* p. 5.
[56] AGA 2009 *op cit* p. 3.

AZ, CA, CO, CT, GA, HI, IN, KS, KY, MA, MN, MT, NV, NH, OH, RI, SC, WI, and VT.[57]

The AGA notes the existence of supplemental program incentives for gas distributors in the following eleven states:

CA, KY, MA, MN, MO, NH, NJ, NY, NV, RI, and WI.[58]

CDM/DSM performance incentives can provide utilities with material relief for lost margins. Kushler, York, and Witte comment that the performance incentive approach

> has tended to be the most common [supplement to DSM cost recovery] because it is usually easier to accomplish than lost revenue recovery mechanisms. It has also often been generally regarded as helping to address both lost revenues and the desire by utilities to be able to "earn a return" on their energy efficiency activities (these two concerns are sometimes lumped together and simply referred to as the utility's 'financial concerns').[59]

Some of the incentive programs require the calculation of program savings, and some require calculations of net benefits. The administrative cost of these programs is therefore non-trivial. The AGA comments in this regard that "a major difficulty with the shared savings incentive is that savings are difficult to measure and verify, and some states have developed problems with measurement and verification activities required to authorize incentive payments".[60]

3.2 Case Studies

We believe that the following five case studies are good choices for an exploration of alternative decoupling approaches that could make sense for Ontario.

- California was the first jurisdiction to implement decoupling true up plans and has been using them off and on for more than thirty years. It is widely recognized to be a North American clean energy leader.
- Oregon and British Columbia have also had extensive decoupling true-up plan experience.
- Maine suspended a decoupling true up plan after a few years. Its experience is often cited by opponents of this decoupling approach as a reason to reject it.

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[57] Maggie Eldridge, Max Neubauer, Dan York, Shruti Vaidyanathan, Anna Chittum, and Steven Nadel, "The 2008 State Energy Efficiency Scorecard", October 2008.
[58] AGA 2009 *op cit* p. 5.
[59] Kushler, York, and Witte *op cit* p. 6.
[60] AGA 2009 *op cit* p. 6.

- Ohio has made one of the largest commitments to retail SFV pricing after a brief experimentation with the decoupling true up approach.

For each state, we will consider where relevant the rationale of the utility in proposing a decoupling plan, the Commission rationale for plan approval, key features of plan design, and notable outcomes.

3.2.1 California

Natural Gas

Most gas distribution service in California is provided by three large utilities, Pacific Gas & Electric ("PG&E"), San Diego Gas & Electric ("SDG&E"), and Southern California Gas. Decoupling true up plans called supply adjustment mechanisms ("SAMs") were instituted for these distributors in the late 1970s at the conclusion of a generic proceeding.[61] The state had experienced gas supply shortages. The consequent risk to distributor earnings was exacerbated by experimental rate designs that included inverted block rates. Utilities generally supported the decoupling concept.[62]

A. The Plans

The first approved plans featured full decoupling true ups that were timed to coincide with purchased gas rate adjustments. For each utility there was initially one large basket, and the PUC punted in its generic decision on the issue of how revenue variances would be allocated between customer classes. Subsequent plans preserved the single basket approach but excluded some price-sensitive customers from decoupling. A cap was placed on earnings, but this provision has not been featured in more recent plans.

The generic decision did not address the issue of RAM design. However, gas utilities proposed RAMs and secured approval in their subsequent filings. Most early RAMs were of hybrid design. A revenue per customer index approved for Southern California Gas was an important early precedent for the approach to RAM design now used by Enbridge. Inflation-only RAMs have also been used in California, and the two largest gas distributors now operate under all-forecast RAMs of stairstep form.

[61] CPUC Decision No. 88835, Case no. 10261, May 1978.
[62] We do not have utility testimony from the early California decoupling proceedings.

B. Commission Rationale

The Commission's rationale for approving the decoupling true up plans for gas distributors placed heavy emphasis on the need to remove utility disincentives for conservation and to rectify the destabilization of earnings that had resulted from the combination of supply uncertainty and experimental rate designs. The CPUC commented in its decision on several issues that have since been raised in decoupling proceedings. Regarding the ability of decoupling to reduce risk, for instance, they stated that "A SAM will reduce the risk to utility shareholders. That reduction in risk should be considered by the Commission in setting a reasonable rate of return in rate proceedings". Responding to critics that the true up plan guarantees a rate of return, the PUC commented that

> A SAM will merely insure that gas utilities achieve the gas margin last found necessary and limit the utility to that margin. Utility expenses other than the purchased cost of gas can and will change between general rate proceedings and those changes will determine whether the gas margin maintained by a SAM will actually produce a rate of return that meets or exceeds the utility's authorized rate of return[63].

C. Outcomes

Decoupling true up plans have been used by California's larger gas utilities in most years since their inception. California utilities have DSM programs, and these programs were ranked number one in the United States in a recent survey. Additional results of this survey are found in Section 3.3. Inverted block rates have continued, but were recently modified pursuant to state legislation.

<u>Electric</u>

A. A Brief History

Most electric service in California is provided by three utilities: PG&E, SDG&E, and Southern California Edison ("SCE"). A restructuring in the 1990s involved a managed bulk power market and lead to extraordinary price run ups. The utilities sold off many generating units but still own substantial generation capacity. They play the leading role in California in the provision of conventional CDM programs.

Decoupling true up plans became an issue for the industry in the late 1970s. A proposal by PG&E to decouple its electric service revenues was rejected by the commission

[63] CPUC Decision No. 88835 (1978), *op cit*.

in 1978 due to an inadequate evidentiary record. In 1980 the commission approved in Decision 92549 a "one way" decoupling mechanism for SCE that returned surplus revenues to customers but not shortfalls.

In 1982 the CPUC instituted two-way decoupling mechanisms, called Electric Revenue Adjustment Mechanisms ("ERAMs"), for PG&E and SDG&E. These had the support of PUC staff and the California Energy Commission as well as the utilities. An ERAM was instituted for SCE in 1983 and for Pacific Power & Light (d/b/a PacifiCorp) in 1984.

The appeal of decoupling true up plans in California electric utility regulation came from several sources. Power conservation became a priority in the state in the 1970s, spurred by generation capacity concerns and high fuel prices. The CPUC declared in 1976 that "Conservation is to rank at least equally with supply as a primary commitment and obligation of a public utility".[64] A California Energy Commission was established to supplement PUC actions to promote conservation.

Electric utilities had experimental rate designs that promoted conservation but increased earnings risk in an environment that included risk from other sources. Companies were building nuclear power plants, and the Commission would not allow the inclusion of the value of construction work in progress in rate base. In addition to its impact on overall risk, this circumstance increased the likelihood that the risk from conservation programs and inverted block rates would raise each company's cost of debt. The Commission was one of the few in the U.S. that favored multiyear rate plans. This raised concern about financial attrition between rate cases.

Despite a generally positive experience, the use of ERAMs fell off in the mid 1990s due, in part, to complications posed by the statutory rate freeze that accompanied retail competition. There was also some thought that CDM might be provided in the future by independent marketers. The return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk in the midst of

[64] See, for example, CPUC D. 85559 (March 1976) p. 489.

the California power crisis.[65] All four of these utilities have subsequently returned to decoupling true up plans and operate under such plans today.

B. The Plans

The CPUC has favored full revenue decoupling mechanisms with one large basket applicable to most services and no cap on rate adjustments. RAMs were initially called attrition rate adjustment mechanisms. The CPUC supplemented the ERAMs with positive CDM performance incentives.

The hybrid approach has been most popular in revenue cap design over the years but is not currently used. There has been experimentation with inflation-only revenue caps, and all current revenue caps are of all-forecast character and have a stairstep form.

C. Commission Rationale

The CPUC has said little about the merits of ERAMs since its earliest decisions. In approving the first ERAM for PG&E, they emphasized its ability to reduce controversy over sales forecasts --- a persistent problem complicated by rate designs --- and to remove utility disincentives to promote all cost-effective conservation.[66] The fact that the ERAM limited overrecovery of the revenue requirement as well as underrecovery was noted. A cap on undercollections proposed by CPUC staff was rejected on the grounds that it was "unnecessary and contrary to our goal of eliminating disincentives of PG&E's pursuing cost-effective conservation measures". The decision approving the first decoupling plan for SCE emphasized the ability of ERAMs to mitigate problems posed by the CPUC's rate design policies.[67]

D. Rate Design

California began experimentation with rate designs before the institution of decoupling true up plans. In the mid 1970s, the CPUC made conservation a central consideration in rate design. Declining block rates were eliminated. Inverted block rates have been used on many occasions over the years.

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[65] The California legislature mandated a return to decoupling in April 2001. See California Public Utilities SEC.10. Section 739.10 as amended by Assembly Bill X1 29 (Kehoe). It provides that "The Commission shall ensure that errors in estimates of demand elasticity or sales to not result in material under or overcollections of the electrical corporations."
[66] CPUC D. 93887 (December 1981).
[67] CPUC D. 82-12-055 (December 1982) p. 154.

Small volume electric customers today face inverted block rates for power distribution services, although the design was recently revised pursuant to legislation. The CPUC has recently implemented decoupling true up plans for *water* utilities as well. Inverted block rates play a central role in the conservation programs of participating utilities.

E. Building Codes and Appliance Standards

California has been a national leader in the establishment of policies outside the regulatory arena which promote energy efficiency. The California Energy Commission monitors and regulates key aspects of the energy economy. This includes the establishment and enforcement of EE standards for buildings and appliances. A Commission study has found that conservation due to appliance and energy efficiency standards has grown substantially over the years and accounts for more than half of the accumulated energy savings in the state since 1980. Following the resumption of decoupling, California instituted an *Energy Action Plan* in 2003 that has been periodically updated. The plan features aggressive new measures to promote energy efficiency and demand response.

It is difficult to ascribe these high standards to the use of decoupling true up plans. We do not know whether California utilities have been more supportive of high standards that utilities in other states. However, California has frequently had governors who are avowedly sympathetic to business interests in the state. It is possible that knowledge of the existence of decoupling true up plans helped them see their way to support for ambitious California Energy Commission policies.

F. Operating Record

Eto, Stoft, and Belden report results of research on the first decade of California ERAM experience.[68] The focus is on the three largest utilities: PG&E, SCE, and SDG&E. Here are some key results

- From 1983 to 1992, the earnings of these companies tended to fluctuate in a narrow range around their allowed rates of return. The actual ROE exceeded the allowed ROE by about 15 basis points on average.
- The ERAMs had little impact on rate volatility, as we noted in Section 2.4.4. For PG&E, rate volatility was actually reduced.

Decoupling true up plans have over the years garnered widespread stakeholder support.

[68] Joseph Eto, Steven Stoft, and Timothy Belden, *op cit.*

G. Solar DG

Solar policy is an important consideration in an appraisal of decoupling in California because the state's policy of net metering for customers with on-site solar resources can erode distribution revenue. The Network for Energy Choices released a study in 2009 that ranked states on policies to promote solar energy.[69] The focus of the study was net metering policy and interconnection standards. In this study, California ranked only seventh, garnering a "B grade" for both net metering and connections. The cap on the amount of net metering is one reason that the state did not receive a higher grade.

However, the study did not consider subsidies and other policies, for which California is noted, that promote development of customer-sited solar resources. The CPUC implemented a California Solar Initiative for major investor-owned electric utilities in 2006. It provides upfront incentives to customers for the installation of solar systems on customer premises. Customer-sited photovoltaic generation capacity has grown rapidly in the state in recent years, pushing against current net metering limits. The Solar Water Heater and Heating Efficiency Act of 2007 has introduced a new rebate program for solar water heating. All three large California utilities are now required to offer feed in tariffs on an experimental basis. The companies have opposed an expansion of the net metering cap until a study of its effects is completed. One concern is what happens when rooftop generation becomes so extensive that supply in a neighborhood exceeds demand.

PEG Research contacted authors of the *Freeing the Grid* study to ask how California ranked with regard to its overall support for solar energy. One (Rusty Haynes) responded by e-mail that

> CA has been at the top of the U.S. state solar heap for many years, primarily due to strong public policy efforts and funding commitments. CA blows the rest of the states away in terms of number and capacity of installed solar-energy systems. There is no publication that rates states on overall policy efforts to promote solar. But if there were, and especially if the study took into account policies implemented during the last 10 years, CA would very likely take the top slot. Other states are catching up, but this will take a long time.

As in the case of building codes, decoupling may have encouraged state government to pursue such aggressive policies by mitigating concern about adverse utility impacts.

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[69] James Rose *et al*, *Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Standards*, Network for New Energy Choices, October 2008.

H. Conservation

As for the impact that decoupling has had on electric CDM, consider first that California has long ranked as a national leader in the area of electric CDM policy. Energy efficiency savings achieved by the utilities fell substantially in the mid-1990s after the suspension of ERAMs. Following the resumption of decoupling, savings rebounded substantially only after the resumption of decoupling. California has the top ranking in a recent survey, which we discuss further in Section 3.3, of state electric CDM programs. But this is likely due in part to positive CDM performance incentives.

Per capita retail sales of electricity in California have been essentially flat since the late 1970s. This is a remarkable fact given the state's high income level. However, it is attributable to many causes, including a structural shift in the economy in favor of commercial rather than industrial activity.

Given the difficulty of identifying the specific impact of decoupling, it is understandable that Kushler, York, and Witte conclude their review of California decoupling's impact by stating that the state's decoupling true up plans are

> one element of a much larger energy policy – a policy that requires utilities to commit large amounts of resources to fund and implement energy efficiency programs. We found no efforts to date that attempt to evaluate the impacts of just the decoupling mechanisms on the utilities' investment and related actions towards energy efficiency programs. Given these tremendous additional changes with [CPUC] targets and approved budgets for energy efficiency programs, we believe that it is difficult to isolate the specific policy impacts of decoupling. However, we also observe that establishing such mechanisms is a valuable complement to achieving the overall policy objective. It's part of a "complete package" to align utility financial interests with public policy interests towards greater levels of energy efficiency.[70]

3.2.2 Oregon

<u>1990s Electric Plans</u>

A. Rationale for Decoupling Proposals

In the early 1990s, the Oregon PUC became concerned about the rising cost of power supply. The Oregon PUC encouraged the use of least cost planning, which made CDM a valued alternative to the construction of additional capacity but could harm utilities

[70] Kushler, York, and Witte (2006) *op cit*. pp. 46-50.

financially. Incentives for utilities to encourage cost-effective CDM procurement would be necessary. As a result, the Oregon PUC opened an investigation into how CDM spending should be incentivized. The investigation concluded by ordering the state's two major vertically integrated electric utilities, Portland General Electric ("PGE") and PacifiCorp to "undertake collaborative processes designed to develop a decoupling mechanism suited to the utility's particular circumstances….the inquiry must lead to a proposal for a specific mechanism and may not limit itself to contemplation of the matter on a theoretical basis."[71] [72] This order was made despite a successful review of PGE's SAVE program, which included both an LRAM and a Shared Savings Incentive.

B. Plan Design and Reasons for Decision: Portland General Electric

PGE's collaborative developed a decoupling true up plan which was combined with a rate case featuring two forward test years. The decoupling plan was designed to be a two year pilot. An all-forecast RAM would use the test year revenue requirements. There would be a single basket for all rate classes. Monthly revenue benchmarks would be compared to weather normalized actual revenues. The plan allowed for decoupling true ups every six months and amortized decoupling adjustments over an 18-month period. Revenues collected via the decoupling mechanism were capped at 3% of base rate revenues. In its order approving the plan the Oregon PUC stated that

> It is still the Commission's policy to encourage conservation by severing the link between sales levels and profits…. Decoupling removes the utility's incentive to promote new sales and does not provide utilities with an incentive to adopt ineffective demand-side management programs. The current system of regulation produces incentives for utilities to increase electricity sales and corresponding disincentives to the pursuit of energy efficiency. Because decoupling separates profits from fluctuating sales levels *regardless* of the cause of the changed sales, it addresses efficiency impacts resulting from *all* effects, including rate design, all utility-sponsored demand-side management activities, and all energy efficiency measures. Moreover, decoupling does not require sophisticated measurement or estimation…. Decoupling does not take the next step and provide a positive incentive for good planning. But it does provide a relatively simple mechanism to remove a variety of short-term perverse incentives inherent in the existing regulatory structure.[73]

[71] *Ibid*. p. 13-14.
[72] It is noteworthy that both the utilities and Oregon PUC staff had reservations about developing decoupling proposals.
[73] Order No. 95-322 March 1995, p. 15.

C. Plan Design and Reasons for Decision: PacifiCorp

PacifiCorp's collaborative also reached consensus on a decoupling true up plan, the Alternative Form of Regulation ("AFOR"), which would begin in 1998 and end in June 2001. Like PGE's plan, the AFOR featured a weather adjustment for actual sales. The RAM was based on a GDPPI – 0.3% escalation formula. All rate classes were to be decoupled with separate baskets created for each major customer class. The plan also featured the requirement that PacifiCorp must notify the Oregon PUC as to whether or not it wanted an extension of the AFOR in 2001.

In its approval of the plan, the Oregon PUC stated that

> the distribution-only AFOR is beneficial to utility customers generally. The plan requires price decreases if warranted under the price adjustment mechanism. Any rate increases under the plan are capped at 2 percent per year, and because of the productivity offsets, will always be less than the general rate of inflation…. These provisions, along with the plan's revenue cap, revenue sharing requirements, and service quality measures, will help ensure that the plan results in benefits for PacifiCorp's customers.[74]

D. Notable Outcomes

PGE's plan was not renewed for three reasons. First, many parties believed that PGE's rates were excessive and had requested an investigation. This may have resulted when PGE's forecasted incremental power costs were above actual incremental power costs as the price of wholesale power fell during the mid 1990s. Second, parties felt that new revenue targets would be needed if decoupling was extended. New revenue targets would likely be time consuming and controversial to develop. Third, as part of the stipulation ending the decoupling plan, PGE agreed to file experimental plans allowing for retail competition for its small commercial and residential services by August 1997. Revenue decoupling was viewed as difficult to administer during a shift to retail competition.

In a 2001 letter to the PUC, PacifiCorp chose not to extend the AFOR and described significant changes in the Oregon regulatory environment that had occurred since the AFOR was approved.[75] These included the California Energy Crisis and legislation that addressed

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[74] Oregon Public Utilities Commission, Order Number 98-191 in Docket UE 94 (Phase II), dated May 5, 1998. p. 9.

[75] Hellebuyck, B., Letter to the Oregon PUC Re: Docket UE 94 (Phase II) dated June 21, 2001.

the issue of retail competition and created a public benefit fund which would encourage conservation and renewable generation.[76]

The following year, the PUC rejected PGE's proposal for a new decoupling program. Staff's testimony on PGE's proposal noted that both PGE and PacifiCorp decreased their CDM expenditures after the onset of decoupling. For both PGE and PacifiCorp, CDM expenditures peaked in 1995.[77] [78] Staff also noted that "while it's fair to indicate that plummeting conservation activity may not actually be a result of each company's decoupling mechanism, but rather due to relatively low wholesale market prices for electricity, it also doesn't hold that decoupling provided for the removal of any disincentives to acquire conservation resources during the period the mechanisms were in place."[79]

Northwest Natural Gas

A. Applicant's Rationale

Northwest Natural Gas (NW Natural) filed for decoupling via the Distribution Margin Normalization mechanism ("DMN") in 2001 to enable increased DSM spending for low-income consumers and to mitigate the effects of declining average use which accelerated after a jump in natural gas commodity prices.

B. Plan Design

NW Natural reached a settlement with Staff which was approved by the Oregon PUC. The settlement between parties was key to the approval of the DMN. The approved DMN was a three year pilot terminating in 2005. The DMN included only 90% of the margin variances in the residential and commercial rate classes. A price elasticity adjustment was added to reflect the tendency of consumers to adjust use as prices changed. Also, margin differentials due to weather were not to be included in the DMN, although those were later addressed by a separate weather normalization mechanism.[80] Residential and commercial customers were to be placed in separate baskets. Margin differentials were thus to be calculated monthly as 90% of the difference between each customer group's weather normalized usage compared to a usage baseline multiplied to a set margin for each customer

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[76] The public benefits fund would be administered by the Energy Trust of Oregon.
[77] Exhibit 101 from the testimony of Stephan Brown and Ming Peng in Docket UE 126.
[78] The year 1995 was the first year of PGE's pilot and two years before PacifiCorp's experiment.
[79] Testimony of Stephan Brown and Ming Peng in Docket UE 126, p. 8
[80] The weather normalization mechanism was approved in the subsequent 2003 rate case.

group.[81] The approved revenue cap was an RPC freeze. DSM programs were transferred to the Energy Trust of Oregon. The plan required an independent study of the effectiveness of the DMN.

C. Reasons for Decision

In approving the DMN, the Oregon PUC stated that

> the elasticity adjustment and partial decoupling mechanism substantially accomplishes NW Natural's goal of better aligning shareholder and customer interests. The conceptual purpose of decoupling has always been to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict. The stipulated mechanism will allow NW Natural to provide customer service support and information related to energy efficiency without causing a negative financial impact on its shareholders.
>
> Customer and environmental groups benefit from three of the company's commitments in the agreement. First, NW Natural's agreement to adopt a service quality measure allows the Commission to monitor customer service performance over the next decade and impose penalties if the company fails to meet established standards. Second, NW Natural's willingness to permanently transfer the company's energy efficiency programs will allow an independent entity to run these programs more effectively and efficiently by eliminating conflicting company goals. Finally, NW Natural's commitment to a general rate case assures the Staff and other parties of an opportunity in the near future to review the company's cost structure and other matters of interest, including whether the company's cost of capital should be reduced to account for decoupling.[82]

D. Notable Outcomes

NW Natural filed a request to extend the DMN in March 2005. As part of the application, the results of the independent study were filed. This study gave the DMN a positive review.

> We have been impressed by the breadth of support that DMN has received. The Energy Trust of Oregon reports that NW Natural has been successful in creating a good working relationship with the Energy Trust, and that NW Natural's efforts to promote energy efficiency effectively complement their own efforts. HVAC distributors believe that NW Natural's marketing efforts, in conjunction with its relationships with consumers, distributors, and the Energy Trust have helped increase sales of high-efficiency furnaces to the point where Oregon has the highest share of high-efficiency furnaces in the

[81] Margins would be updated when rate cases were concluded.
[82] Public Utilities Commission of Oregon, Order 02-634, issued September 12, 2002, p. 9

> nation (as a percentage of new furnace sales). The Citizens' Utility Board of Oregon, the Northwest Energy Coalition and a number of CAP agencies believe that the Public Purposes Funding established in conjunction with the DMN is beneficial for consumers. The Natural Resources Defense Council and American Gas Association released a joint statement regarding the positive environmental effects of decoupling, specifically citing NW Natural's experience as an example of the positive outcomes that decoupling can yield.[83]

This review led to an approved settlement in which the DMN was extended through September 2009. The settlement included one change to the DMN, to allow 100% recovery of the any variances in margins, except for those caused by weather.

A 2007 settlement extended the DMN through October 2012. This settlement included an extension of the weather adjustment mechanism and a rate case moratorium through August 2011.[84] Based on the successes of the DMN, Cascade Natural Gas filed for a decoupling plan and received the approval of other stakeholders in a settlement which was approved by the Oregon PUC.[85]

<u>Portland General Electric's 2008 Proposal</u>

A. Applicant's Rationale

In 2008 PGE filed for a new decoupling plan. It stated that it filed for the plan because it anticipated that any emissions standards proposed by Congress would lead to increased conservation and result in either flat or declining average use. PGE also declared that it

> actively supported additional funding for energy efficiency efforts of the Energy Trust of Oregon and, in fact, were a prime mover in achieving legislation that allows additional energy efficiency funding through electric prices. We are committed to working with interested parties either within the context of this rate case or outside it to identify and fund expanded energy efficiency investments and other cost-effective demand-side measures.[86]

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[83] Daniel Hanson and Steve Braithwait, "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005.

[84] This a rare example where an RPC freeze has coincided with a rate case moratorium. Except for a rate case in 2003 required by the first DMN settlement, NW Natural will have avoided rate cases for 13 years at the end of its rate case moratorium. Rapid customer growth in the service territory, which includes Portland, made possible brisk productivity growth through the realization of sizable scale economies.

[85] This decoupling mechanism is currently being reviewed and a report on the effectiveness of Cascade's decoupling mechanism is expected in March 2010.

[86] Direct Testimony of James Piro in UE 197, February 2008, p. 19.

Rate design was also a consideration in the decision to propose decoupling, as residential customers faced inverted block rates. PGE commented in its rate design testimony that "absent our decoupling proposal, we would advocate for higher customer charges to reduce the impact of recovering fixed distribution costs on a volumetric basis."[87]

B. Plan Design

The approved plan has a two year term and features an RPC Freeze for the RAM. Under this plan, weather normalized distribution, transmission, and fixed generation revenues collected by volumetric rates would be compared with a fixed charge per customer multiplied by the actual number of customers. Any difference between the volumetric recovery and the fixed charge per month would be calculated and placed in a balancing account to be refunded or collected at a later date. The approved plan also limits decoupling rate charges to customers with a soft cap set at 2% of the approved revenue requirements.[88] Refunds to customers would not be capped. Like the original NW Natural DMN, PGE is required to submit an assessment of the effectiveness of the decoupling mechanism. This assessment is not expected to be filed until late 2010 or 2011.

C. Reasons for Decision

The Oregon PUC stated in its order approving the resumption of decoupling for "PGE" that

> While the parties do not disagree that relying on volumetric charges to recover fixed costs creates a disincentive to promote energy efficiency, they contend that decoupling is unnecessary because, with the [Energy Trust of Oregon ("ETO")] running energy efficiency programs in PGE's service territory, the Company has limited influence over customers' energy efficiency decisions. We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether it supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE.[89]

[87] Direct Testimony of Doug Kuns and Marc Cody in UE 197, February 2008, p. 8.
[88] This subsequently became a 2% hard cap for decoupling rate adjustments that would be charged to customers.
[89] UE 197, January 2009, p. 27

3.2.3 Maine [90]

Rationale

Central Maine Power ("CMP") is the largest electric utility in Maine and, during the years of its decoupling plan, had a vertically integrated operation. Under a Maine Public Utilities Commission ("MPUC") rule passed during the late 1980s, each electric utility was required to develop plans to meet customer demand at the lowest cost. CMP filed for a least-cost plan which included a shared savings incentive and a lost revenue adjustment mechanism. As part of its order ordering revisions to the original CMP plan, the MPUC noted that

> CMP's proposed incentive system would have no effect on costs other than those incurred for DSM and non-utility purchased power. There is thus no assurance that utility supply-side thrift would enhance profits, or that choosing the least-cost mix of energy resources would result in maximum profits….Current incentives to build load through power marketing, regardless of the cost of meeting that load, would remain….In summary, earnings under this proposal would, as now, rise as sales rise, and fall as sales fall, unless the fall in sales results from utility DSM efforts, in which case earnings would rise.[91]

The MPUC viewed this as insufficient motivation to promote CDM and told CMP to explore adding a mechanism that will decouple sales from profits.

Plan Design

In 1991, CMP and several other parties brought forth a Joint Report which included a pilot decoupling mechanism. The decoupling plan ultimately proposed and approved by the MPUC was a three year pilot "ERAM" featuring an RPC freeze for the RAM. There was one basket for all service classes. Differences between actual and allowed RPC were to be calculated monthly, multiplied by the actual number of customers served, and accrued until the end of the year. These would be allocated to each rate class in proportion to its share of the test year non fuel revenues. The allocated amount for each rate class would then be charged or credited to customers based on a forecast of the total kWh sales for each rate class during the period over which recovery was to occur. One month after the approval of the

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[90] A similar description to this case study is found in the October 1995 Electricity Journal article *Maine's Electric Revenue Adjustment Mechanism: Why It Fizzled* by Leslie Hudson, Stephanie Seguino, and Ralph E. Townsend, p. 74-83.

[91] Maine Public Utilities Commission, Order in Docket 90-085 dated April 25, 1990. pp. 3-4.

ERAM, the Maine legislature held a hearing and imposed the condition that any ERAM adjustments would be capped at 1% with the remainder being deferred to future proceedings.

Reasons for Decision

In its decision, the Commission's rules on least-cost planning were an important consideration as its goal was to "reasonably assure that energy efficiency programs … are more profitable to the utility than are more costly alternatives regardless of whether the more costly alternatives are supply or demand side resources."[92]

Notable Outcomes

The approved ERAM had three key features that influenced subsequent events. First, sales forecasts used to set rates did not properly reflect the onset of a serious recession and were described by the MPUC as being "an essentially mediocre set of forecast models that passed some minimal statistical tests but were also flawed in a variety of ways."[93] If sales forecasts weren't reasonably accurate, accrued amounts would not reach zero, resulting in additional interest to be paid by ratepayers or the company. Second, by setting up one basket for all rate classes under the ERAM, individual rate classes were at risk for a downturn in the demand of other rate classes.

Third, the number of customers in the RPC denominator was defined as the number of customers in the historic *test year* 1989 while the allowed revenue was defined as the revenues approved by the MPUC for the *rate year* beginning in March 1991. This would result in an unnecessarily large RAM adjustment.

The economic climate in Maine made the operation of the RAM more controversial. The economy was in recession. Weather was milder than normal. Sales were far below forecasted amounts.

The result of the ERAM and local business conditions was large deferrals followed by a large requested rate increase by CMP in October 1991 to recover deferrals for the ERAM just months after its approval. The rate increase was withdrawn by CMP because of a decline in interest rates by the Federal Reserve, the fact that ERAM deferrals had protected shareholders from the decline in sales, and a desire to avoid a rate increase during a time of economic difficulty. Other conditions were also putting pressure on rates which would make

[92] Maine Public Utilities Commission, Order in Docket 90-085 dated May 7, 1991. p. 2.
[93] Maine Public Utilities Commission, Order in Docket 90-076 dated March 8, 1991. p. 130.

a successful rate increase for decoupling much less likely. These other causes of rate increases included fuel-related rate hikes, due to the Gulf War and the company's reliance on oil-fired generation, and a change in rate design that apportioned a larger share of fixed costs to residential customers. This combination of factors led to potential residential rate increases of more than 50% excluding the effects of the ERAM or a rate case.

The mechanism resulted in actual revenue below allowed revenue for each of the 22 months under which the ERAM had been in place. By December 1992, there was a net unrecovered balance of $52.4 million. If the mechanism was allowed to operate as intended for the remainder of the pilot period, an "additional amount of about $41.5 million would be accrued to be recovered from ratepayers."[94] Parties also acknowledged that the ERAM deferrals were not caused by successful DSM programs.

These large accruals under the ERAM had been booked by CMP as revenue, but in May 1992, the Securities and Exchange Commission determined that large accruals must be recovered within two years. CMP thus filed for MPUC approval of a two year recovery period for the ERAM. The MPUC decided to pursue the suspension of the ERAM to prevent further rate shock to residential customers. CMP had reserved the right to file a rate case during the decoupling plan and in fact filed for a temporary rate increase in response to the MPUC's decision to investigate suspending the ERAM.

A withdrawal of the rate case was part of a stipulation under which CMP was permitted to recoup its revenue shortfalls to that point under the decoupling plan. The decoupling pilot was suspended at the end of November 1993, three months earlier than the pilot's termination date. The DSM incentive plan was also terminated. In effect, the experiment in Maine ended due to a juxtaposition of a poorly implemented decoupling plan, and political and economic forces. Since the recession in Maine was prolonged it is likely that rates would have risen anyways, due to one or more conventional rate cases, in the absence of the decoupling plan.

Further reviews of decoupling in Maine were conducted by the MPUC in 2004 and 2008.   The MPUC stated that

> [t]he Commission has great reluctance regarding the adoption of any type of revenue decoupling mechanism. Although the mechanism has theoretical

[94] Maine Public Utilities Commission, Order Approving Stipulation in dockets 90-085-A and 90-085-B dated February 3, 1993. p.2.

> appeal, the Commission has substantial concern over the unintended consequences that may accompany the adoption of a regulatory structure which is so dependent on unpredictable events. Such unintended consequences rapidly developed with the Commission's experiment with ERAM in the early 1990s.[95]

3.2.4 British Columbia

Rationale

BC Gas (dba Terasen Gas) was the decoupling pioneer in Canada. The company provides distribution services to most gas customers in British Columbia and also operates a transmission system that competes with Westcoast Energy. Terasen was ordered to file a revenue decoupling proposal by the British Columbia Utilities Commission ("BCUC") after it withdrew a proposal for a weather normalization mechanism. The company had experienced a series of warm winters in the early 1990s that led to rate case controversy over volume forecasts.[96]

Plan Design

The Revenue Stabilization Adjustment Mechanism ("RSAM") was originally designed to account for revenue variances of residential and commercial customers only during the winter months. For the summer months, increased sales would be promoted. Balances would be placed in a deferral account and recovered or repaid over three years. The revenue cap approved for the RSAM was a forecast for 1994 and 1995 of the revenue requirement.[97]

Terasen filed for new rates for 1996 and 1997. This application resulted in a settlement approved by the BCUC that modified the RSAM to include revenue variances for all months. The RAM approved for the RSAM remained the multi-year forecast of the revenue requirement.

The revenue cap for the RSAM changed during the 1998-2000 revenue requirements application, as a revenue cap indexing OM&A expenses were approved. This revenue cap

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[95] Maine Public Utilities Commission, Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability, presented to the Joint Standing Committee on Utilities and Energy of the Maine legislature. February 2004, p.48.

[96] IndEco, *Declining Average Use per Customer: Issues and Options for Canada's Natural Gas Distribution Utilities*, December 2006. p. 30.

[97] It should be noted that plant additions greater than $5 million require a Certificate of Public Convenience and Necessity approval before they can be added to rate base. Because of this process, all Terasen Gas revenue caps are technically hybrids, as large plant additions are treated differently from other types of spending.

was subsequently extended to 2001. For 2002, rates were frozen. Rates were reset for 2003 and a revenue cap based on indexing was approved for 2004-2007. This RAM was subsequently extended through 2009.

Terasen Gas recently filed a traditional COS revenue requirements application with test years in 2010 and 2011. In justifying a movement away from an indexed revenue cap, Terasen Gas acknowledged the improvements in operating performance under multiyear rate plans. However, Terasen sought large increases in customer care, DSM spending, and capital expenditures. In a settlement approved by the BCUC, the new approach to revenue cap design was confirmed but the decoupling true ups continued.

Reasons for Decision

In its decision approving the RSAM in 1994, the BCUC stated that

- The incentive for the Company to pursue short-run sales in the winter period would be eliminated, thereby eliminating the potential conflict between the demand-side pursuit of economically efficient energy services … and short-run profit maximization by the gas utility.
- Sales forecast risks to utility shareholders would be substantially reduced for sales to the weather sensitive residential and commercial customers---which represents the major revenue volatility of the Utility.
- Because marginal cost pricing initiatives, such as seasonal rates, would no longer be associated with increased risks for shareholders, utility management would be less reticent to support such improvements.
- The contentiousness associated with regulatory review of short-run energy demand forecasting would be largely eliminated.[98]

Notable Outcomes

Throughout its existence, the RSAM has not been particularly controversial, as approval for its extension has typically been requested in one sentence as part of its revenue requirements applications.[99] Approval of the RSAM has also been relatively straightforward via settlements among parties without discussion by the BCUC in decisions. The RSAM in effect has not changed greatly since 1996. Out of seven Canadian gas distributors which

[98] British Columbia Utilities Commission, Decision for BC Gas'1994/95 Revenue Requirements Application. August 4, 1994. p. 4-5.

[99] The Consolidated Settlement Document establishing the 1998-2000 revenue cap plan references an extension of the RSAM once. The reasons for decision approving this settlement does not include a discussion of the RAM.

operated DSM programs in 2004, Terasen was the fourth largest distributor and had the fifth largest DSM expenditure.[100]

Another sign of the RSAM's acceptance was the petition and approval of a decoupling true up plan for Pacific Northern Gas ("PNG") during 2003. PNG had been experiencing similar difficulties in creating accurate sales forecasts as there had been a steep drop in residential and small commercial average use during 2001 and 2002. The approved PNG RSAM included residential and small commercial classes with variances and true ups to be calculated from one basket. RSAM deferrals were calculated as the use per account variance multiplied by both the actual number of customers and the unit margin per gigajoule. The three year recovery period for deferrals in the Terasen Gas plan was also included in the PNG RSAM. One notable difference from the Terasen Gas RSAM is that PNG's RSAM used an RPC freeze for a RAM. PNG has filed for a rate case every year since 2003.

3.2.5 Ohio

Vectren Energy Delivery of Ohio

Vectren Energy Delivery of Ohio ("Vectren") is the gas distributor serving the Dayton area. In 2005, Vectren filed for approval of a revenue decoupling mechanism for its gas operations in western Ohio. Vectren proposed decoupling because of a decline in average use amongst its customers and stated an interest in applying its experience in DSM programs from Indiana and in responding to national and regional policies supporting enhanced DSM programs.

A stipulation led to the approval of a decoupling true up plan and also provided for gas DSM. The decoupling mechanism included residential and general service customers with each rate schedule having a separate basket. Actual base revenues would be weather normalized while allowed base revenue would be calculated as the order approved base revenue per customer multiplied by the actual number of customers. The difference would be calculated monthly, and the total difference in revenue each year would be recovered based on projected sales over the next year.

[100] IndEco Strategic Consulting (2005), *DSM Best Practices*, p. 13.

In approving the stipulation, the Commission stated that "the Commission continues to believe that it is in the public interest, in order to promote energy efficiency, to decouple the link between gas consumption with the company's ability to meet its revenue requirements."[101]

Vectren proposed a renewed decoupling mechanism that would gradually shift from the true up approach to the SFV approach but included true ups for at least two years. Vectren listed the benefits of SFV pricing over true ups as including administrative simplicity, a bill that would be more easily understood for customers, and bill stability.[102] The Commission ultimately approved the use of SFV pricing phased in two steps without the interim true up mechanism.[103] [104]

Duke Energy Ohio

In 2007, Duke Energy Ohio ("Duke"), a combined gas and electric utility serving Cincinnati, filed a rate case for its gas operations which included a proposal for a decoupling true up plan modeled on Vectren's approved plan. Duke had three purposes for revenue decoupling: to have a better opportunity to recover Commission approved base revenues, to remove Duke's disincentive to promote energy conservation, and to provide a clearer price signal to customers.[105]

In this case, Staff proposed SFV pricing as an alternative. In developing its position, Staff noted the long standing trend of declining average use of natural gas. It also stated that "SFV rate design recognizes the fact that a natural gas distribution utility's costs are predominantly fixed in nature."[106] Staff also discussed the potential for regulatory simplicity by avoiding annual true-ups.[107] In addressing the issue of customer incentives for conservation, Staff witness Puican stated

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[101] Public Utilities Commission of Ohio, *Supplemental Opinion and Order in Case 05-144-GA-UNC*. June 27, 2007, p.18.
[102] These rationales are presented in the direct testimony of H. Edwin Overcast in docket 07-1081-GA-ALT.
[103] This order also authorized $4 million of customer-funded energy efficiency programs and the establishment of a tracker mechanism for further energy efficiency expenditures.
[104] The phase in of SFV pricing is as follows: from $7.00 per month to $13.37 per month upon the approval of Vectren's tariffs. This will be followed by a revenue neutral change to $18.37 per month charge in February 2010. As of February 2010, there will be no volumetric charge.
[105] Direct Testimony of Donald Storck in Case 07-589-GA-AIR before the Ohio Public Utilities Commission.
[106] Prefiled Testimony of Stephen Puican on behalf of the Public Utilities Commission of Ohio in Case 07-590-GA-ALT. February 28, 2008, p. 5.
[107] Staff's commentary on this issue may be a subtle reference to Vectren's true ups. The issue of weather normalization methodology was a source of concern for Staff.

> When evaluating customer incentives to conserve, one needs to look at the total variable rate a customer faces and not just the distribution rate…. Whatever variable distribution rate is ultimately approved in this proceeding, it will be relatively small in comparison to the cost of the gas itself. Customers will always achieve the full value of the gas cost savings when they conserver regardless of the distribution rate…. Artificially inflating the volumetric rate beyond its true variable cost basis skews the analysis and will cause an over-investment in conservation…. The relatively small potential disincentive for customers to conserve due to the reduction in the volumetric rate is more that [*sic*] offset by the removal of the Company's disincentive to actively promote and fund energy efficiency.[108]

Ultimately, the Commission agreed with Staff's SFV rate design. In its order approving Duke's rate increase, it noted additional benefits to the Staff's proposal, including stable bills and being easier for consumers to understand. The Commission declared that a commitment to conservation initiatives will be an important consideration in approving future decoupling proposals. In terms of price signals incentivizing customer conservation, the Commission stated that

> a levelized rate design sends better price signals to consumers…. This commodity portion, the cost of the actually gas used, is the biggest driver of the amount of a customer's bill. Therefore, gas usage will still have the biggest influence on the price signals received by the customer when making gas conservation decisions, and customers will still receive the benefits of any conservation efforts in which they engage. While we acknowledge that there will be a modest increase in the payback period for customer-initiated energy conservation measures with a levelized rate design, the result is counterbalanced by the fact that the difference in the payback period is a direct result of inequities within the existing rate design that cause higher use customers to pay more of their fair share of the fixed costs than low-use customers.[109]

As a result of the Commission's decision, Duke's previous customer charge of $6 per month was escalated immediately to $15 per month through September 2008. For the period October 2008 through May 2009, the customer charge became $20.25 per month. In June 2009, the customer charge was set to be $25.33 per month. These changes in customer charge were revenue neutral and would correspond with simultaneous declines in the volumetric charge. Even in June 2009, there would be a volumetric charge that is above what is expected with full SFV pricing.

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[108] *Ibid*, p.6-7.
[109] Public Utilities Commission of Ohio. Opinion and Order for Case No. 07-590-GA-ALT. May 28, 2008, p.19.

SFV pricing was subsequently approved for both Dominion East Ohio Gas and Columbia Gas. Once Vectren's decoupling plan was replaced with SFV pricing, all of Ohio's major natural gas distributors had adopted SFV pricing. The Ohio Consumers Council and Ohio Partners for Affordable Energy appealed the commission's decisions for Duke and Dominion East Ohio to the Ohio Supreme Court on several grounds, including the issues of rate gradualism and whether it undermined state policy to encourage conservation. The court recently affirmed the Commission's decision, arguing in part that rate gradualism is not a factor that the Commission is required to apply in every rate design case.[110] The Supreme Court affirmed these decisions.

3.3 Performance Rankings

Before drawing some conclusions and observations about decoupling experience, we provide here some information on the approaches to decoupling in the states that are noted for a high level of CDM/DSM effort. We are especially interested to learn if large utility programs make particular use of one approach to decoupling, and whether decoupling true up plans are in fact used in states with large independently administered programs. Our commentary on these results is consolidated with other conclusions and observations in the following section.

Kushler, York, and Witte (2009) report on a study that ranks states in terms of the overall scale and effectiveness of EE programs.[111] This study identified the top 14 states in terms of electric utility sector EE performance. We present here their rankings, together with a characterization of their decoupling treatments.[112] States where most CDM/DSM programs are provided by independent agencies have a bolded font.

	State	Decoupling Treatment
1.	California	Decoupling true up plans & supplemental performance incentives
2.	Massachusetts	Performance incentives, just phasing in true up plans
3.	Connecticut	LRAMs, performance incentives, beginning true up plans
4.	**Vermont**	**Decoupling true up plans**

[110] *Ohio Consumers' Counsel v. Public Utility Commission*, Ohio Supreme Court Slip Opinion No. 2010-Ohio-134.

[111] Martin Kushler, Dan York, and Patti Witte, "Meeting Aggressive New State Goals for Utility-Sector Energy Efficiency: Examining Key Factors Associated With High Savings", ACEEE Report No. U091, March 2009.
[112] These comparisons are not intended to suggest causation.

5.	**Wisconsin**	**Performance incentives**
		1 of 4 large utilities now has decoupling true up plan
6.	**New York**	**Resuming decoupling true up plans after long hiatus**
7.	**Oregon**	**Decoupling true up plan for largest utility**
8.	Minnesota	Performance incentives
9.	**New Jersey**	
10.	Washington	
11.	Texas	
12.	Iowa	
13.	Rhode Island	Performance incentives
14.	Nevada	Performance incentives

Here is the analogous Kushler, York and Witte (2009) ranking for *natural gas* efficiency programs. States where most CDM/DSM programs are provided by independent agencies once again have a bolded font.

	<u>State</u>	<u>Decoupling Treatment</u>
1.	California	Decoupling true up plans for all utilities
2.	Massachusetts	LRAM, phasing in decoupling true up plans for all utilities
3.	**Vermont**	**Decoupling true up plan for largest utility**
4.	**Wisconsin**	**Performance incentives**
		Decoupling true up plans for 1 of 5 large utilities
5.	Minnesota	Performance incentives
		Just starting decoupling true up plan for largest utility
6.	**New York**	**LRAM, performance incentives**
		Phasing in decoupling true up plans for all utilities
7.	**Oregon**	**Decoupling true up plans**
8.	**New Jersey**	**Performance incentives**
		Decoupling true up plans for 2 of 3 largest utilities
9.	Connecticut	LRAM
10.	Washington	Decoupling true up plans for 1 large utility
11.	Iowa	
12.	Nevada	Performance incentives

13. Utah Decoupling true up plan for largest utility

The Canadian Energy Efficiency Alliance issues annual report cards on the emphasis placed on energy efficiency by Canada's federal and provincial jurisdictions. Jurisdictions are compared with regard to a wide range of indicators that includes energy efficiency budgets, building codes, appliance standards, and public outreach programs. A wide variation in emphasis on energy efficiency has been found. Two provinces (British Columbia and Manitoba) currently have A+ ratings and another two (Quebec and Ontario) have A ratings.

3.4 CONCLUSIONS AND OBSERVATIONS

Our review of decoupling experience permits us to draw some conclusions about revenue decoupling.

- Decoupling, using one of the three established approaches that we have discussed, is now practiced by the most American states with large-scale CDM/DSM programs.
- CDM/DSM performance incentives are also widespread.
- Utilities in most states are given flexibility in the design of a decoupling approach. It is not uncommon for states to use several approaches simultaneously.
- It is common in U.S. decoupling true up plans for some service classes to be excluded. These are typically classes where customers are especially sensitive to the terms of service. The great majority of approved plans use *revenue* cap rather than *price* cap approaches to RAM design.
- While by no means ubiquitous, true up plans are now the single most popular approach to decoupling for both the gas and electric power industries of the United States. Most US jurisdictions in which, as in Ontario, there is a pronounced emphasis on CDM/DSM now have at least one utility operating under a decoupling true up plan. Such plans are now mandated by law and/or commission policy for all utilities in three of these jurisdictions. In jurisdictions where there is only one such plan it is often recently implemented, suggesting that true up plans are gaining favor.

- There is no reason to think that the popularity of the true up approach is due to any superiority in removing disincentives for conventional utility CDM/DSM programs. After all, several states (*e.g.* Connecticut and Massachusetts) have only recently implemented decoupling true up plans, long *after* CDM/DSM programs reached a large scale. CDM/DSM performance incentives are associated with many of the largest programs, suggesting that these are a noteworthy driver. Moreover, decoupling true-up plans have been adopted for utilities in a number of states (including Hawaii, New York, New Jersey, Oregon, Vermont, and Wisconsin) in which most CDM/DSM programs are implemented by independent agencies. Decoupling true up plans, furthermore, have been adopted for gas utilities in a number of states that are not leaders in the promotion of energy efficiency.
- These facts suggest that the popularity of decoupling true up plans is due to the other reasons that we discussed in Section 2.4. They are an efficient means for compensating utilities for declining average use that results from external events such as an independently administered CDM/DSM programs. Like SFV pricing, they compensate utilities for lost margins at lower administrative cost than LRAMs, and this has been valued even by regulators who have just a few jurisdictional utilities. Decoupling true-ups and SFV pricing have the further advantage of removing disincentives for less conventional utility initiatives to encourage EE and customer-sited DG. This has been noted explicitly by several commissions.
- Decoupling true up plans are far more widely used than SFV pricing. The restrictiveness of SFV pricing is doubtless a reason for this. Regulators don't like the tendency of SFV pricing to encourage energy purchases. Many utilities operating under decoupling true up plans have introduced or maintained inverted block rates. Higher customer charges are also a concern of regulators, although we have shown that this is not an essential feature of SFV pricing. It should also be noted that most regulators in the United States do not have jurisdiction over a large number of energy utilities. The "best in class" administrative cost of SFV pricing therefore does not carry much weight.

- In summary then, the popularity of decoupling true up plans may be traced primarily to their ability to provide attrition relief for slow volume growth due to a wide range of demand drivers, and to remove disincentives for a wide range of utility initiatives, at reasonable administrative cost and without high customer charges or counterproductively low usage charges.
- Despite these advantages, decoupling true up plans are not necessarily preferable to LRAMs and SFV pricing in all circumstances. LRAMs can still make sense where utilities provide most CDM/DSM programs; there are companion CDM/DSM performance incentive mechanisms that also require savings estimates; there is little interest in the social engineering of distribution rates and little scope for utilities to promote energy efficiency by other unconventional means; and where there are only a few utilities to regulate. SFV pricing can still make sense where there are numerous jurisdictional utilities, and/or regulators are not interested in socially engineered distribution rates.
- Changing circumstances can cause regulators to change their preferred decoupling approaches. Most obviously, decoupling true up plans and SFV pricing make more sense once the decision is made to entrust some or all CDM/DSM programs to an independent administrator. If the utility is the administrator, it has made more sense in some states to adopt decoupling true up plans once average use by small volume customers is declining.

4. REVENUE ADJUSTMENT MECHANISMS FOR DECOUPLING TRUE UP PLANS

RAMs are a critically important feature of the design of decoupling true up plans. We consider first how price cap indexes can be used for this purpose. There follows a discussion of the design of revenue caps. The discussion sheds a light on alternatives to fully index-based revenue caps that might have appeal to some Ontario power distributors. Some readers will prefer to pass over this somewhat arcane issue and proceed to the discussion of the Ontario situation in Chapter 5.

4.1 Price Cap Approaches to Attrition Relief

PEG's November 2007 report to the Board on gas IR provides an extensive discussion on the design of attrition relief mechanisms, for use in multiyear rate plans, that take account of declining average use. Assuming that a gross domestic product implicit price index ("GDPIPI") is used as the price cap index inflation measure, a price cap index with growth rate formula

Growth PCI = growth GDPIPI – X [2]

conforms to the index logic conventionally used in North America to design PCIs provided that the X factor can be decomposed into the following terms.

PD = Productivity Differential	The difference between the productivity trends of the relevant utility industry (*e.g.* power distribution) and the economy
IPD = Input Price Differential	The difference between the input price trends of the economy and the industry
AU = Average Use Factor	Adjustment for the differential impact of output growth on revenue and cost
Stretch = Stretch Factor	X factor component that shares with customers the financial impact of any expected acceleration of productivity growth.

In this breakdown, the productivity index of the industry involves an output index that measures the impact of output growth on *cost* rather than *revenue*. The impact of a specific output variable (*e.g.* the number of customers served) on cost can be measured by its cost *elasticity*. An output index involving *multiple* output measures would therefore have growth rates that are weighted by the *share* of each measure in the sum of the total cost elasticities.

The elasticity estimates could be drawn from econometric research on the drivers of utility cost. Such research has generally shown that, for gas and electric power distribution, the number of customers served is the dominant output-related cost driver. We could then, for simplicity, measure industry productivity growth using the number of customers as the output measure.

A decomposition of this kind had special usefulness in the regulation of Ontario's gas utilities at the time that IR plans were developed. The available data did not permit accurate measurement of the trend in their productivity. Data from similarly-situated utilities in the United States could be used for this purpose but these utilities could have different average use trends. The decomposition made it possible to set rates based on U.S. cost trends and Ontario-specific use per customer trends.

Suppose, now, that the X factor term of the price cap index excludes an average use term. A PCI of this kind would reflect only industry cost trend considerations. This kind of price cap index does not compensate utilities for any decline in average use that they experience. However, prices could, in principle, be subject to a further adjustment each year to account for any tendency of average use to decline. Moreover, this adjustment could be subject to a true up mechanism. This is the general approach to decoupling that is used in the Union Gas plan. One advantage of this approach is that the PCI applies to rates for all service classes, including those exempted from decoupling, and there is no need to allocate the updated revenue requirement each year by service class.

4.2 Revenue Caps

Index research has been used for more than twenty years to design formulas for utility rate and revenue requirement escalation. These provide the basis for formulaic and hybrid revenue caps and can also be used in the cost forecasts needed for stairstep revenue caps. We provide here a non-technical discussion of the use of indexing in revenue cap design. The discussion begins with consideration of some basic indexing concepts.

4.2.1 Basic Indexing Concepts

Price Indexes

Price indexes are widely used in today's economy to measure price trends. Indexes can summarize the trends in the prices of multiple products by taking weighted averages of these trends. Indexes of trends in the prices a utility pays for its inputs customarily use cost share weights because these weights capture the impact of input price growth on cost.

Productivity Indexes

Productivity (trend) indexes measure changes in the efficiency with which firms convert inputs to outputs. The growth trend of such an index is the difference between the trends in output and input quantity indexes.

$$trend\ Productivity = trend\ Output\ Quantities - trend\ Input\ Quantities \qquad [3]$$

An output quantity index for a firm or industry summarizes trends in the amount of work that is performed. An input quantity index summarizes trends in the amounts of production inputs used. Productivity indexes vary in the scope of inputs that are considered. A TFP index measures productivity in the use of all inputs. Indexes can also be designed to measure productivity in the use of OM&A inputs.

4.2.2 Use in Revenue Cap Design

Full Indexation

The full indexation approach to revenue cap design takes full advantage of the logic of economic indexes. The analysis begins by considering that the growth trend in the revenue requirement of a utility industry operating under cost of service regulation equals the growth trend of its corresponding cost:

$$trend\ Revenue = trend\ Cost. \qquad [4]$$

A basic result of index logic is that the trend in a utility's cost is the sum of the trends in appropriately specified industry input price and quantity indexes:

$$trend\ Cost = trend\ Input\ Prices + trend\ Input\ Quantities. \qquad [5]$$

Suppose, next, that we use the number of customers to measure the effect of output growth on cost. Then

$$\begin{aligned} trend\ Cost = {} & trend\ Input\ Prices \\ & - (trend\ Customers - trend\ Input\ Quantities) + trend\ Customers \end{aligned}$$

$$= \textit{trend Input Prices} - \textit{trend Productivity} + \textit{trend Customers.} \qquad [6]$$

The trend in cost decomposes into the trends in input price and productivity indexes and the number of customers served. In this formula, the number of customers is used as the output measure in the productivity index.

This is an important result for several reasons. One is that it demonstrates that a fully compensatory revenue cap should account for inflation, productivity, and customer growth. Another is that it provides the basis for a formulaic revenue cap that escalates revenue for local input price and customer growth and uses peer group data only to establish a productivity target. A full indexation formula is currently used in the revenue decoupling plan of Enbridge Gas Distribution and has previously been used by two large California utilities, Southern California Edison and Southern California Gas.

Relation [6] is one example of a full indexation formula for revenue cap design. An equivalent result can be obtained by escalating revenue per customer using the formula

$$\textit{trend Cost/Customer} = \textit{trend Input Prices} - \textit{trend Productivity} \qquad [7]$$

and then using a utility's latest customer numbers to establish the new revenue requirement. A revenue cap with a design based on this formula is sometimes called a revenue per customer index.

Inflation Only Revenue Caps

Special, more simplified formulas are sometimes used in revenue cap design. For example, if customer growth is assumed to equal the productivity growth target, relation [6] simplifies to

$$\textit{trend Cost} = \textit{trend Input Prices.} \qquad [8]$$

Relation [8] makes the most sense as a basis for revenue cap design when utilities are facing customer growth that is similar to a reasonable productivity growth target. However, it will tend to undercompensate companies with unusually *rapid* customer growth, and may *over*compensate utilities with unusually *slow* customer growth. This approach therefore does not make much sense for jurisdictions in which there are large differences between utilities in the pace of customer growth.

A few approved revenue caps feature inflation and productivity terms but not a customer growth allowance. An example is the CPI – 1% revenue cap approved in 2008 for the power distribution services of Central Vermont Public Service. Our analysis suggests that an escalation formula that accounts for inflation and productivity growth but not for customer growth will be uncompensatory.

Revenue Per Customer Freezes

Revenue per customer freezes were noted in Section 2.2.2 to be a common form of formulaic revenue cap. Relation [6] shows that an RPC freeze provides appropriate compensation for cost growth only when a company's input price growth is similar to a reasonable target for its productivity growth. This assumption is generally unreasonable because productivity growth as here defined is typically a good bit slower than input price inflation. Our research therefore suggests that RPC freezes are substantially uncompensatory as the primary basis for adjusting utility revenue requirements.

PEG Research has interviewed the staff of several utilities operating under RPC freezes. All of the respondents indicated that they did not expect these mechanisms to provide full attrition relief. All retained the right to file rate cases and several of the utilities that we contacted have done so.[113] For example, Idaho Power came in for a rate case in 2008, the second year of its decoupling plan. The fact that RPC freezes apply chiefly to gas distributors makes sense since these utilities are more likely to settle for an inadequate RAM in order to obtain some relief from the relatively pronounced problem of declining average use that they often face.

Revenue Cap Inflation Measures

Resolved that a fully compensatory revenue cap reflects input price inflation, other important design issues must still be addressed. One is whether it should be expressly designed to track *input* price inflation. There are numerous precedents for the use of industry-specific inflation measures in revenue cap, most notably in the indexation of OM&A expenses in hybrid revenue caps. However, some revenue caps instead feature measures of *macroeconomic* inflation, such as the CPI or GDPIPI, which measure inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products but also include government services and capital equipment.

[113] Moskovitz and Swofford note that "The RPC decoupling method is not designed to change the length of time between utility rate cases. The utility remains free to initiate a general rate case if its financial condition requires it." See David Moskovitz and Gary B. Swofford, "Revenue per Customer Decoupling" in Steven M. Nadel, Michael W. Reid and David R. Wolcott, eds. *Regulatory Incentives for Demand-Side Management*. Washington, D.C. and Berkeley CA, American Council for an Energy Efficient Economy, 1992.

Studies by PEG Research personnel have found over the years that inflation in the economy's final goods and service tends to be slower than inflation in utility input prices.

4.2.3 All Forecast Revenue Caps

Our discussion suggests that all forecast revenue caps for energy distributors should take account of inflation, productivity, and customer growth trends to be fully compensatory. All forecast revenue caps have several advantages in accomplishing this goal. One is that they can sidestep the complex issue of input price and productivity measurement. Complexity is especially great in the measurement of capital cost. Many participants in the regulatory arena are unfamiliar with the measurement of capital price and quantity trends. Another advantage of all forecast revenue caps stems from the fact that the full indexation revenue caps usually reflect a judgment concerning *long* run industry productivity trends. The resultant productivity targets are often unsuitable for funding the surges in maintenance expenses and/or major plant additions that utilities sometimes make.

The chief downside to using all forecast revenue caps is their rigidity. Inflation and other business conditions that effect utility cost do not always turn out as forecasted. The result can be windfall gains or losses for utilities and higher operating risk.

4.2.4 Hybrid Revenue Caps

The hybrid approach to revenue cap design was noted in Section 2.2.2 to use a mix of formulaic and forecasting methods. In North America, hybrid revenue caps have the following typical features.

- Budgets for non-energy OM&A expenses are escalated automatically during the decoupling period using formulas that reflect new information. These formulas usually involve an inflation measure and may also feature explicit adjustments for customer growth and a productivity growth target.
- Plant addition budgets are set using a mix of forecasting and indexation. The budget for each year is set in advance, in the dollars of the test year, but subject to adjustment in the attrition years of the plan for new information about construction cost inflation. Major plant additions are sometimes subject to a separate approval process.
- The future budget for the cost of plant ownership is otherwise forecasted using traditional cost of service methods. This is fairly straightforward inasmuch as the

depreciation and return on rate base that result from a set of older investments and predetermined plant additions is straightforward to calculate. The most unpredictable element, the cost of obtaining funds in capital markets, is sometimes subject to separate adjustments during the decoupling plans to reflect new information.

This general approach to revenue cap design has a number of advantages. Indexing is used where it is least controversial, in the escalation of OM&A expenses. There is no need for the complex calculations needed to measure input price and productivity trends for utility plant. The treatment of capital cost is flexible enough to accommodate surges in plant additions.

4.2.5 Revenue Cap Design Precedents

Regarding the popular forms of revenue cap design, Table 1 shows that the RPC freeze approach was first employed by Puget Sound and Central Maine Power in the early 1990s. RPC freezes are currently used by many utilities outside California. Most are gas utilities, but this approach has also recently been adopted by electric utilities in the District of Columbia, Idaho, Maryland, and Wisconsin.

The hybrid approach was noted above to have been the most common to revenue cap design in California over the years. Inflation only and full indexing revenue caps have also been used, and most California utilities currently operate under all-forecast revenue caps. Revenue per customer freezes have not been used, because California utilities are required to use multiyear rate plans and RPC freezes are uncompensatory in this context. Outside of California, all-forecast revenue caps have been the norm over the years in New York. In New York, all forecast revenue caps have been facilitated by a forward test year tradition and a longstanding commission aversion to the use of formulaic rate and revenue caps.

Despite the popularity of RPC freezes in the gas industry, the great majority of revenue caps that have been approved around the world and over time are designed to provide automatic attrition relief for inflation as well as customer growth. All forecast and hybrid revenue caps have been the principle means of providing such relief. Their popularity may be attributed to the flexibility with which they can provide relief for inflation and customer growth, under a variety of operating conditions, without capital cost index research.

5. APPLICATION TO ONTARIO

In this chapter of the report we apply the analytical framework developed in Chapter Two and the lessons learned from decoupling experience in Chapter Three to appraise the decoupling approaches currently used by the OEB for gas and electric power distribution and consider whether reforms in these approaches may be warranted. We begin in Section 5.1 with a quick review of key considerations that indicate the need for some form of decoupling and might point to the desirability of a particular approach. We then examine these key considerations for the Ontario gas utility industry in Section 5.2 and draw some policy conclusions. The power distribution industry is considered in Section 5.3.

5.1 KEY BUSINESS CONDITIONS

Our discussion in Section 2.3 suggested that revenue decoupling in some form is a sensible addition to the regulatory system to the extent that some combination of the following conditions hold.

- policymakers place a high priority on CDM/DSM goals;
- utilities administer conventional CDM/DSM programs and/or can promote CDM/DSM in other ways
- average use of the distribution system by small volume customers is, for whatever reason, expected to decline;
- production and consumption of gas, and production of power in central generating stations, causes significant environmental damage that is not reflected in the prices of energy commodities;
- demand forecasts are a time consuming focus of rate rebasings;
- regulators favor multiyear rate plans; and
- rate rebasings use historic test years so that rates when implemented do not reflect declines in average use between the rate year and the test year,

The particular approach to decoupling that makes the most sense in a particular jurisdiction depends on additional circumstances. The following questions have a central role in the analysis.

- Is average use declining for reasons other than utility CDM/DSM programs?
- Do utilities have ways to encourage CDM/DSM goals other than conventional CDM/DSM programs?
- Do existing rate designs have high usage charges and low customer charges, or would regulators like to move in this direction?
- Is the number of utilities in the jurisdiction large enough that economies in the regulatory process are an especially important consideration?
- Are regulators open to RAMs that reduce the frequency of rate cases?

We turn now to a consideration of these and other conditions in Ontario

5.2 Appraising the Need for Revenue Decoupling: Gas Sector

5.2.1 Gas Distribution Utilities

Most gas distribution service is provided in Ontario by two utilities, Enbridge Gas Distribution and Union Gas. Both companies operate large distribution systems and Union additionally operates a sizable transmission system.[114] The transmission system traverses southern Ontario and at its eastern terminus competes with TransCanada Pipelines and U.S. carriers to deliver gas to the Toronto/Niagara market.[115] Union's ex franchise transmission services and its T&D services to the many large industrial customers in its service territory require flexible terms of service in order to respond to changing and often competitive market conditions.

5.2.2 Provincial Commitment to DSM

The government of Ontario has encouraged improved energy efficiency by provincial gas users. Both gas utilities have maintained sizable DSM programs for many years, as we

[114] Both utilities also have sizable gas storage operations.
[115] Both companies also operate sizable storage facilities under terms that are subject to light handed regulation.

discuss further in Section 5.2.4. Enbridge and Union were operating large gas DSM programs in 2007, before the start of their incentive regulation plans.[116] [117] Numerous recent provincial policies designed to encourage CDM will also encourage natural gas conservation and these are discussed in section 5.3.2.[118]

5.2.3 Average Use Trends

Declines in average use of gas by small-volume customers were noted in Section 3.1 to be a chronic problem for many North American gas distributors. Information on the average use trends experienced by Ontario gas distributors are provided in Table 3. PEG Research performed the weather normalization calculations. Inspecting the results, it can be seen that the weather normalized average use by residential customers of Enbridge and Union declined by 1.43% on average in the years 2004-2008.

Over the same years, average use by general service customers of the companies grew by 0.43% annually on average. However, it is especially hard to draw conclusions about trends in general service use per customer from such data. Energy use by businesses is, after all, sensitive to fluctuations in the demand for their services as well as to temperature and energy commodity prices. Average use is also sensitive to change in the composition of customers due, in part, to moves between service classes. For example, average use in a given service class can increase if customers in the class have diverse delivery volumes and the number of users with comparatively high usage increases disproportionately.

5.2.4 Regulatory System

General Features of Ontario Regulation

Some general features of Ontario regulation merit discussion at this juncture. Rate cases for Ontario gas distributors typically involve a recent historic year (typically a year ending a few months before the filing), a bridge year (the year of the filing), and a forward test year (typically the year after the filing). This means that rate cases produce rates that are reflective of recent average use trends.

[116] IndEco Strategic Consulting *Canadian Natural Gas Distribution Utilities' Best Practices in Demand Side Management: Study Update*, 2007. p. 19.
[117] However, it should be noted that Manitoba Hydro has the highest ratio of DSM expenditures to total utility revenues, followed by Enbridge and Union.
[118] The most notable effect will be from provincial building code updates.

Table 3

Trends in Average Use of Small Volume Customers of Enbridge and Union

	Residential		Small Business	
Year	Actual [1]	Normalized [1]	Actual [2]	Normalized [2]
1992	2.50%	2.95%	3.20%	3.66%
1993	-0.91%	-0.46%	-0.29%	0.18%
1994	-1.43%	-0.98%	0.29%	0.76%
1995	-2.86%	-2.40%	-0.77%	-0.30%
1996	2.50%	2.96%	4.50%	4.97%
1997	-3.73%	-3.27%	-4.61%	-4.13%
1998	-21.91%	-21.44%	-18.95%	-18.46%
1999	4.40%	4.87%	5.33%	5.81%
2000	9.54%	10.01%	6.77%	7.26%
2001	-9.38%	-8.90%	-8.43%	-7.94%
2002	4.32%	4.80%	5.77%	6.27%
2003	3.94%	4.42%	3.80%	4.29%
2004	-5.67%	-5.19%	-5.41%	-4.91%
2005	-2.94%	-2.45%	-1.16%	-0.65%
2006	-11.56%	-11.07%	-9.49%	-8.99%
2007	7.90%	8.40%	9.52%	10.03%
2008	2.66%	3.16%	6.18%	6.69%
Averages				
1991-2008	**-1.33%**	**-0.86%**	**-0.22%**	**0.27%**
2000-2008	**-1.34%**	**-0.86%**	**0.10%**	**0.60%**
2003-2008	**-1.92%**	**-1.43%**	**-0.07%**	**0.43%**

[1] These are average growth rates in actual and weather normalized deliveries per customer of Enbridge's revenue class 20, and Union's residential revenue classes 01 and M2.

[2] These are average growth rates in actual and weather normalized deliveries per customer of Enbridge's revenue class 48, and Union's small business revenue classes 01, M2 and 10.

In 2004, the OEB convened a Natural Gas Forum that considered new approaches to the regulation of jurisdictional gas utilities.[119] In its final report on the Forum, the Board found that its goals for the regulation of gas utility base rates are best served by multiyear incentive regulation ("IR") plans with annual rate adjustment mechanisms designed with the aid of index research.[120]

In 2006, a consultation process began on the development of gas IR plans. Pacific Economics Group ("PEG") advised Board Staff in this proceeding. The company's November 2007 report explained why declines in the average use of gas merit explicit consideration when designing the rate escalation provisions of IR plans.[121] Both companies were found to face material average use declines by the small volume customers that account for the bulk of their distribution base rate revenue requirement.[122] The report identified several means to address the average use problem, including a decoupling true up plan with a revenue cap of the revenue per customer index form.[123]

Utility DSM Programs

Ontario gas utilities have been engaged in DSM for more than a decade. The Board established a framework for regulating DSM in 1993. Enbridge and Union have been filing DSM plans since 1995.[124]

A common framework for the regulation of these companies' DSM programs was approved in 2006.[125] A stated reason for this initiative was that "the Board has been required to frequently make decisions on similar DSM issues for the two large gas utilities…This has lead to increased regulatory burden for all parties and inconsistent practices for the two utilities".[126] Under the framework, the companies must file and gain approval for multiyear DSM plans every three years. The budgets provided for in the plans are required minimums. The initial 2007 budgets of the utilities involved substantial increases (*e.g.* 16% for Enbridge

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[119] We use the word "utility" rather than "distributor" in this Section since Union Gas operates a sizable transmission system and its regulation is addressed in the same proceeding as the company's distribution system.
[120] OEB, *Natural Gas Regulation in Ontario*: *A Renewed Policy Framework*, March 2005.
[121] See Mark Newton Lowry *et al*, *Rate Adjustment Indexes for Ontario's Natural Gas Utilities*, Pacific Economics Group, 2007. The declining average use issue is discussed at pp. ix, 8, 16, 49-52, and 95-96.
[122] *Ibid* pp. 49-52.
[123] *Ibid*, pp. 16-18 and 70-71.
[124] OEB, *Report of the Board*, EBO-169-III, June 1993.
[125] OEB, *Decision With Reasons*, EB-20060021, August 2006.
[126] *Ibid* p. 4.

and 22% for Union) from previous levels. Budgets in the two out years of the plan are required to rise formulaically (5% annually for Enbridge and 10% for Union). Utilities file Evaluation Reports on their DSM activities annually. These reports require the assistance of one or more independent auditors, who are paid by the utility.[127]

A Demand Side Management Variance Account ("DSMVA") is used to true up the variance between actual DSM spending and the budget incorporated in rates. Spending in excess of budgets is capped at 15% and requires a showing that incremental benefits were realized. The DSMVA recovers the revenue variances in a given class from the customers in that class.

An LRAM adjusts base rates annually for any variance, in the prior year, between actual lost margins from each company's DSM programs and the lost margins that are included in the base rate revenue requirement. Base rates therefore rise when DSM programs are more successful than expected and fall when they are less successful. The LRAM recovers the lost revenue from each service class from the customers in that class.

The companies are subject, additionally, to supplemental incentives to pursue DSM vigorously and effectively. There are separate incentive mechanisms for conventional DSM programs and "market transformation programs". With regard to the former, a shared savings mechanism provides compensation for how close the utility comes to achieving the total resource cost ("TRC") target. This requires estimates of DSM program savings. The compensation is provided on a sliding scale, with the company receiving greater awards for incremental improvements that exceed the target. A Shared Savings Variance Account records the actual amount of the shareholder incentive earned by the company as a result of its DSM programs.

Market transformation programs are programs intended to make a permanent change in the energy market, are not necessarily measured by the number of participants, and have a long term horizon. Rewards for market transformation programs are considered on a case-by-case basis and are capped at low levels. Estimates of energy savings from such programs can be difficult to make accurately.

[127] The auditor must provide opinions on proposed DSMVA, SSM, and LRAM amounts, which are discussed further below.

Current Rate Plan: Union Gas

Union now operates under a "multiyear ratemaking framework" that was established by the Board in its decision on EB-2007-0606.[128] The framework involves a price cap plan with a term of five years (2008-2012). Rates for all services are escalated annually by a price cap index with a growth GDPIPI – X formula. Since the 1.82% X factor excludes an average use adjustment it is essentially a "cost only" price cap index as discussed in Section 4.1 above.

Rates for services M1 and M2 (small and large volume general services, respectively, in the southern operations area), and 01 and 10 (small and larger volume general services, respectively, in the northern and eastern operations area) are subject, additionally, to an average use adjustment. These four services account for about 81% of the in-franchise delivery and storage base revenue requirement in Union's draft Rate Order for 2010. The IR settlement states that "The parties agree that it is appropriate during the IR term to adjust rates to reflect the impact of changes in average use per general service customer on a class-by-class basis."[129]

The average use adjustment for these service classes has two components. One component is an adjustment, to the volume used to compute the volumetric charge, for a forecast of the change in average use. The forecasted change is calculated as the average of the three most recent year's changes in the actual weather normalized volume use per customer in the rate class. The settlement states in Section 4.1 that "this methodology is similar to how the volume losses associated with DSM are handled when rates are determined." The second component of the adjustment uses an Average Use Per Customer deferral account to record as a debit (credit) the margin variance resulting from the difference between the actual and forecasted change in *weather normalized* use-per-customer. This is a partial decoupling true up plan. Actual and forecasted rates of decline in use-per-customer exclude the impacts attributable to Union's DSM program, which are captured separately by the LRAM. For 2010, the adjustments to volumes for declining average use are 0.6% reductions for Rates M1 and M2, 0% change for Rate 1, and a 6.5% *increase* for Rate 10.

[128] OEB, EB-2007-0606, January 2008.
[129] OEB, EB-2007-0606, Settlement Agreement filed January 3, 2008, p. 13.

Current Rate Design: Union Gas

Rate design was noted in Section 2.1 to have a major effect on the sensitivity of utility earnings to slowing growth in average use. The rate designs for small volume customers that Union Gas proposes in its draft rate order for 2010 are provided in Table 4.[130] For Rate 01 there is a monthly customer charge of $19.00 and five tiers of declining block volumetric rates for delivery service. The customer charge accounts for a substantial 50% of the Rate 01 revenue requirement. For Rate 10 there is a monthly customer charge of $70.00 and five tiers of declining block volumetric rates for delivery service. The customer charge accounts for only about 11% of the Rate 10 revenue requirement. For Rate M1 there is a monthly customer charge of $19.00 and three tiers of declining block volumetric rates for delivery service. The customer charge accounts for a substantial 66% of the revenue requirement. For Rate M2 there is a monthly customer charge of $70.00 and four tiers of declining block volumetric rates for delivery service. The customer charge accounts for only about 13% of the revenue requirement.

The rate plan provides for customer charges for rate classes 01 and M1 to rise by $1 annually over each of the remaining years of the IR plan, with corresponding and revenue neutral reductions in volumetric charges. The customer charges for Rates 10 and M2 are fixed for the duration of the plan.

Tables 4a-4f also show the hypothetical results that would be obtained with SFV pricing in the same rate year. For Union, the monthly customer charge for Rate 01 would roughly double to about $38. The monthly customer charge for Rate M1 would rise from $19.00 to about $29. The monthly customer charge for Union's Rate 10 would rise from $70 to about $637. The monthly customer charge from Union's Rate M2 would rise from $70 to about $530.

Current Rate Plan: Enbridge Gas Distribution

Enbridge now operates under an IR plan that was detailed in a settlement approved by the Board in its EB-2007-0615 decision.[131] The plan involves an indexed revenue per

[130] EB-2009-0275
[131] OEB, EB-2007-0615, February 2008.

Table 4a

Rates For Small-Volume Customers of Ontario Gas Distributors

Union Gas Rate 01 - Proposed Rates Effective 1/1/2010

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	67,413	3,548,064	**$**	**19.000**	**49.80%**
Volumetric Charge	10^3m^3	First 100 m^3	$	17,058	199,627	**$**	**0.085**	
		Next 200 m^3	$	22,302	279,154	**$**	**0.080**	
		Next 200 m^3	$	10,152	133,683	**$**	**0.076**	
		Next 500 m^3	$	9,211	127,377	**$**	**0.072**	
		Over 1,000 m^3	$	9,237	133,246	**$**	**0.069**	
		Total Volumetric Charge	$	67,959				**50.20%**
Total Revenue			**$**	**135,372**				**100.00%**

Hypothetical SFV Pricing Scenario

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	135,372	3,548,064	**$**	**38.154**	**100.00%**
Volumetric Charge	10^3m^3	First 100 m^3	$	-	199,627	**$**	**-**	
		Next 200 m^3	$	-	279,154	**$**	**-**	
		Next 200 m^3	$	-	133,683	**$**	**-**	
		Next 500 m^3	$	-	127,377	**$**	**-**	
		Over 1,000 m^3	$	-	133,246	**$**	**-**	
		Total Volumetric Charge	$	-				**0.00%**
Total Revenue			**$**	**135,372**				**100.00%**
Change in Monthly Customer Charge						**$**	**19.154**	

Source: EB-2009-0275, Union Gas Draft Rate Order Working Papers, Schedule 4.

Table 4b

Rates For Small-Volume Customers of Ontario Gas Distributors

Union Gas Rate 10 - Proposed Rates Effective 1/1/2010

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	2,488	35,539	**$**	**70.000**	**10.99%**
Volumetric Charge	10^3m^3	First 1,000 m^3	$	1,788	24,575	**$**	**0.073**	
		Next 9,000 m^3	$	8,811	152,137	**$**	**0.058**	
		Next 20,000 m^3	$	5,296	107,108	**$**	**0.049**	
		Next 70,000 m^3	$	3,238	73,556	**$**	**0.044**	
		Over 100,000 m^3	$	1,009	43,006	**$**	**0.023**	
		Total Volumetric Charge	$	20,142				**89.01%**
Total Revenue			**$**	**22,630**				**100.00%**

Hypothetical SFV Pricing Scenario

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	22,630	35,539	**$**	**636.757**	**100.00%**
Volumetric Charge	10^3m^3	First 1,000 m^3	$	-	24,575	**$**	**-**	
		Next 9,000 m^3	$	-	152,137	**$**	**-**	
		Next 20,000 m^3	$	-	107,108	**$**	**-**	
		Next 70,000 m^3	$	-	73,556	**$**	**-**	
		Over 100,000 m^3	$	-	43,006	**$**	**-**	
		Total Volumetric Charge	$	-				**0.00%**
Total Revenue			**$**	**22,630**				**100.00%**
Change in Monthly Customer Charge						**$**	**566.757**	

Source: EB-2009-0275, Union Gas Draft Rate Order Working Papers, Schedule 4.

Table 4c

Rates For Small-Volume Customers of Ontario Gas Distributors

Union Gas Rate M1 - Proposed Rates Effective 1/1/2010

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	223,459	11,761,016	**$**	**19.000**	**66.39%**
Volumetric Charge	10^3m^3	First 100 m^3	$	40,600	910,401	**$**	**0.045**	
		Next 150 m^3	$	32,175	760,599	**$**	**0.042**	
		Over 250 m^3	$	40,355	1,094,409	**$**	**0.037**	
		Total Volumetric Charge	$	113,130				**33.61%**
Total Revenue			**$**	**336,590**				**100.00%**

Hypothetical SFV Pricing Scenario

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	336,590	11,761,016	**$**	**28.619**	**100.00%**
Volumetric Charge	10^3m^3	First 100 m^3	$	-	910,401	**$**	**-**	
		Next 150 m^3	$	-	760,599	**$**	**-**	
		Over 250 m^3	$	-	1,094,409	**$**	**-**	
		Total Volumetric Charge	$	-				**0.00%**
Total Revenue			**$**	**336,590**				**100.00%**
Change in Monthly Customer Charge						**$**	**9.619**	

Source: EB-2009-0275, Union Gas Draft Rate Order Working Papers, Schedule 4.

Table 4d

Rates For Small-Volume Customers of Ontario Gas Distributors

Union Gas Rate M2 - Proposed Rates Effective 1/1/2010

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	5,862	83,737	**$**	**70.000**	**13.20%**
Volumetric Charge	10^3m^3	First 1,000 m^3	$	2,914	75,271	**$**	**0.039**	
		Next 6,000 m^3	$	13,895	365,867	**$**	**0.038**	
		Next 13,000 m^3	$	10,757	300,762	**$**	**0.036**	
		Over 1,000 m^3	$	10,971	331,298	**$**	**0.033**	
		Total Volumetric Charge	$	38,537				**86.80%**
Total Revenue			**$**	**44,399**				**100.00%**

Hypothetical SFV Pricing Scenario

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	44,399	83,737	**$**	**530.219**	**100.00%**
Volumetric Charge	10^3m^3	First 1,000 m^3	$	-	75,271	**$**	**-**	
		Next 6,000 m^3	$	-	365,867	**$**	**-**	
		Next 13,000 m^3	$	-	300,762	**$**	**-**	
		Over 1,000 m^3	$	-	331,298	**$**	**-**	
		Total Volumetric Charge	$	-				**0.00%**
Total Revenue			**$**	**44,399**				**100.00%**
Change in Monthly Customer Charge						**$**	**460.22**	

Source: EB-2009-0275, Union Gas Draft Rate Order Working Papers, Schedule 4.

Table 4e

Rates For Small-Volume Customers of Ontario Gas Distributors

Enbridge Gas Rate 1 (residential) - Rates Effective for 2009

	Billing Unit	Rate		Revenue Requirement ($000's)	Unites		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	335,442	20,965,129	**$**	**16.000**	**48.5%**
Volumetric Charge	m^3	First 30 m^3	$	51,808	596,244	**$**	**0.087**	
		Next 55 m^3	$	70,346	865,328	**$**	**0.081**	
		Next 85 m^3	$	72,524	942,995	**$**	**0.077**	
		Over 170 m^3	$	161,791	2,196,992	**$**	**0.074**	
		Total Volumetric Charge	$	356,468				**51.5%**
Total Revenue			**$**	**691,910**				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	691,910	20,965,129	**$**	**33.003**	**100.0%**
Volumetric Charge	m^3	First 30 m^3	$	-	596,244	**$**	**-**	
		Next 55 m^3	$	-	865,328	**$**	**-**	
		Next 85 m^3	$	-	942,995	**$**	**-**	
		Over 170 m^3	$	-	2,196,992	**$**	**-**	
		Total Volumetric Charge	$	-				**0.0%**
Total Revenue			**$**	**691,910**				**100.0%**
Change in Monthly Customer Charge						**$**	**17.003**	

Source: EB-2008-0219, Enbridge Exhibit B, Tab 3, Schedule 8.

Table 4f

Rates For Small-Volume Customers of Ontario Gas Distributors

Enbridge Gas Rate 6 (general service) - Rates Effective for 2009

	Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	104,786	1,905,194	**$**	**55.000**	**33.9%**
Volumetric Charge	m^3	First 500 m^3	$	40,671	538,315	**$**	**0.076**	
		Next 1050 m^3	$	37,082	642,051	**$**	**0.058**	
		Next 4500 m^3	$	52,348	1,155,669	**$**	**0.045**	
		Next 7000 m^3	$	26,481	710,156	**$**	**0.037**	
		Next 15250 m^3	$	20,916	620,099	**$**	**0.034**	
		Over 28300 m^3	$	26,689	812,698	**$**	**0.033**	
		Total Volumetric Charge	$	204,187				**66.1%**
Total Revenue			**$**	**308,972**				**100.0%**

Hypothetical SFV Pricing Scenario

	Unit	Rate		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	NA	$	308,972	1,905,194	**$**	**162.174**	**100.0%**
Volumetric Charge	m^3	First 500 m^3	$	-	538,315	**$**	**-**	
		Next 1050 m^3	$	-	642,051	**$**	**-**	
		Next 4500 m^3	$	-	1,155,669	**$**	**-**	
		Next 7000 m^3	$	-	710,156	**$**	**-**	
		Next 15250 m^3	$	-	620,099	**$**	**-**	
		Over 28300 m^3	$	-	812,698	**$**	**-**	
		Total Volumetric Charge	$	-				**0.0%**
Total Revenue			**$**	**308,972**				**100.0%**
Change in Monthly Customer Charge						**$**	**107.174**	

Source: EB-2008-0219, Enbridge Exhibit B, Tab 3, Schedule 8.

customer cap and has a five year term (2008-2012). In each of the plan's four attrition years the base revenue requirement is, effectively, escalated for GDPIPI inflation and the forecasted growth in the total number of customers served less an implicit X factor that takes the form of an "inflation coefficient".

With regard to declining average use, the settlement states that "the Parties agree that the revenue per customer cap methodology incorporates the forecast impact of changes in average use on an annual forecast basis."[132] Each year, the total revenue requirement resulting from the RAM must be allocated between rate classes. The updated revenue requirement for each class is then converted to rates using a new forecast of the billing determinants for that class. The volume forecasts involve forecasts of customer growth, heating degree days, and use per customer that employ sophisticated econometric models. There is a further adjustment for the expected impact of company DSM programs.

An Average Use Variance Account ("AUTUVA") has been established for Rate 1 (residential) and Rate 6 (general service) that captures the revenue impact of all variances between the forecasted and actual weather normalized use per customer. Rates 1 and 6 accounted for about 66% and 30%, respectively, (for a total of 96%) of Enbridge's 2009 distribution revenue requirement.[133] The volume variances exclude, by agreement, the volumetric impact of company DSM programs. This, too, is a partial decoupling true up plan. Rates are adjusted each year to fully draw down the AUTUVA balance. Thus, there is no cap on the decoupling true ups.

Current Rate Design: Enbridge

With regard to rate design, Tables 4e and 4f show that for Rate 1 there was in 2009 a monthly customer charge of $16.00 and four tiers of declining block volumetric rates for delivery service.[134] The customer charge accounted for a substantial 49% of the Rate 1 2009 revenue requirement. For Rate 6 there was a monthly customer charge of $55.00 and six tiers of declining block volumetric rates. The customer charge accounted for about 34% of the 2009 distribution revenue requirement. Under SFV pricing the monthly customer charge

[132] EB-2007-0615 Exhibit N1 Tab 1 Schedule 1 p. 15.
[133] OEB Rate Order, EB-2008-0219 Exhibit B Tab 3 Schedule 4 Page 1, filed 2008-08-26.
[134] Rate data are drawn from OEB Rate Order, EB-2008-0219 Exhibit B Tab 3 Schedule 8 Page 1, filed 2008-08-26.

for Rate 1 would roughly double to about $33. The monthly customer charge for Rate 6 would rise from $55.00 to about $162.

The IR plan permits customer charges for Rates 1 and 6 to escalate by $1 and $5 respectively in each remaining year of the plan. Offsetting and revenue neutral reductions in volumetric charges are required. For other rate classes, fixed and variable charges must increase by an equal percentage.

5.2.5 Appraisal

Gas utilities in Ontario have been subject for some time to declining average use by the residential customers that account for the bulk of their distribution revenues. Utilities undertake most DSM programs, and these programs are sizable. Since, additionally, the Board prefers multiyear rate plans for gas utilities, there is a need for some form of decoupling between rate cases.

Both utilities already have substantial protection from the financial attrition that results from declining average use. Forward test years are used to set rates, and there are high and rising fixed charges for residential customers. The IR plans of Enbridge and Union contain LRAMs and partial decoupling true up mechanisms. Each company's mechanism has creative features that enrich the growing body of decoupling precedents.

With regard to the best form of decoupling, the declines in average use are due to external trends in business conditions as well as to utility DSM programs. Utilities can promote DSM goals by means other than conventional DSM programs. These include rate designs with higher volumetric charges and market transformation programs. There are few large gas utilities in the province. Each utility has a shared savings incentive mechanism that requires the regular calculation of DSM savings.

Our review of decoupling options suggests that the current decoupling arrangements are reasonable under these conditions. LRAMs make some sense given the small number of utilities and the simultaneous use of the Shared Savings Mechanisms that require estimates of DSM savings. The partial decoupling true up plans are an appropriate supplement to the LRAMs, although the need for them is reduced by the high customer charges. However, small refinements to the established approaches merit consideration in the next round of IRs.

1. LRAMs could be eliminated, with the partial decoupling true up mechanisms used to address the lost margins from utility DSM plans and other sources. The economy in

regulatory procedure from this step would not be large, however, unless the role of savings calculations in the shared savings mechanisms is scaled back or eliminated.

2. Revenue can be decoupled, additionally, from weather fluctuations. This would provide a further small simplification to regulation by reducing the role of weather normalization calculations in the decoupling true up mechanism. More important, perhaps, is its ability to foster experimentation with alternative rate designs that more effectively promote DSM goals. Customer charges can be lowered, and volumetric charges raised. The resultant increase in rate volatility can be contained by soft caps on rate adjustments without weakening performance incentives. A full decoupling true up plan would also achieve a further reduction in operating risk that reduces financing cost, and any gains can be shared with customers.

5.3 Appraising the Need for Decoupling: Power Distributors

5.3.1 Power Distribution Utilities

Power distribution service is currently provided in Ontario by more than eighty separate local distribution companies with varying capabilities. The larger distributors include Hydro One Networks, Toronto Hydro Electric, Powerstream, Hydro Ottawa, and Enersource Hydro Mississauga. None of distributors own an appreciable amount of generating plant and nearly all transmission services in Ontario are provided by Hydro One.[135]

5.3.2 Provincial Commitment to CDM

In recent years, the Ontario government has intensified its efforts to promote conservation and alternative energy sources. This is a sharp change from the previous policy where most electricity CDM was eliminated in Ontario between the middle 1990s and 2004 due to sufficient electricity supply and a general trend away from CDM among North American jurisdictions where industry restructuring took place.

The need for an enhanced electricity CDM policy became apparent after the Canadian government agreed to the Kyoto Protocol, especially as Ontario's government committed itself to phase out coal fired power plants.[136] These plants comprised over ¼ of Ontario's generating capacity, while much of its nuclear fleet was nearing the end of its useful

[135] Great Lakes Power also provides transmission services.
[136] This phase-out is required to be complete in 2014.

operating life. This situation required decisions on whether to build, refurbish, or renew nearly 25,000 MW of Ontario's electricity capacity.

In 2004 remarks by Ontario's premier to the Legislative Assembly, the government's commitment to conservation was made clear.

> We have to slow the endless spiral of increasing demand. It's simply not sustainable. So we're asking Ontarians to stop the spiral of demand --- and we will give Ontarians the information and tools they need to save money on their bills, as they save electricity. When it comes to electricity, Mr. Speaker, it's much cheaper for our province to conserve it, than to generate it…and it's much cheaper for our consumers to save it than to pay more for it…. Our government is taking bold action to help make Ontario a North American leader in conservation…. I'm talking about nothing less than creating a profound shift in the culture of this province.[137]

To fulfill these goals, numerous policies and programs were approved including programs from the Ontario Ministry of Energy and Infrastructure ("MEI"), the Ontario Power Authority ("OPA"), and building codes established by the Ontario Ministry of Municipal Affairs and Housing ("MMAH").

The MEI has the leading role in developing conservation policy and related legislation, including laws and regulations affecting major players in the industry such as the OEB and the OPA. As an early act to kickstart CDM in Ontario, the Energy Minister wrote to all distributors in 2004 to encourage them to offer CDM programs.[138] It has run numerous advertisements on television, radio and in newspapers. The MEI also administers the Home Energy Savings Program. This program, which matches federal government grants from its ecoEnergy initiatives, provides a rebate for half of an energy audit and if the recommendations of the audit are followed within 18 months of the audit, rebates of up to $10,000 are available.

The OPA was established to ensure that Ontario's long-term electricity needs are met. A key part of this mission is to enhance opportunities for conservation and energy efficiency to ensure the success of the government's electricity mandates. A July 2006 directive from the MEI ordered the OPA to assume responsibility for organizing the delivery and funding of

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[137] Remarks by Premier Dalton McGuinty, Premier of Ontario on Building a Culture of Conservation: Statement to the Legislative Assembly.

[138] A June 2003 directive of the Energy Minister ordered the OEB to investigate CDM options and the role distributors should play in CDM activities. A May 24, 2004 letter by the Minister of Energy authorized distributors to defer expenses for CDM activities pending a prudence review of the OEB.

CDM programs through distributors in Ontario.[139] [140] The OPA was also directed to support the Ontario Energy Board in its continuing efforts to reduce barriers to CDM including decreases in revenues due to distributors' conservation programs.[141] A second key responsibility of the OPA is to develop an Integrated Power System Plan, a 20 year plan designed to enable Ontario to meet its electricity demand through a variety of sources and includes conservation programs to reduce peak demand in line with government mandated targets.

The OPA has also managed numerous Demand Response programs. In addition to these responsibilities, the OPA is home to the Conservation Bureau, the Technology Development Fund, and the Conservation Fund. The Conservation Bureau was the Ontario government's conservation advocate, promoting conservation through public and media activities and annual reports.[142] The Technology Development Fund and Conservation Fund are designed to grant money to new technologies and adding to the conservation capabilities in the marketplace.

Changes in Ontario law required the MMAH to place an emphasis on energy efficiency in building code updates. The latest approved enhancements to minimum energy efficiency standards phased in between 2006 and 2012 include more energy efficient windows, higher insulation levels for ceilings, walls, and foundation walls, and greater efficiency for gas and propane-fired furnaces. These standards exceed those of the federal government. When fully effective in 2012, these changes are expected to cause energy savings of 35% for new home construction and will harmonize with the Natural Resources Canada's EnerGuide 80 requirements which take effect in 2012. The EnerGuide 80 rating is considered excellent and is near to the perfect score of 100, which is a house that is well insulated, sufficiently ventilated, and requires no purchased energy on an annual basis.

In 2008, Ontario joined the Western Climate Initiative ("WCI"). The WCI is an international block devoted to reducing greenhouse gas emissions and participants include the states of California, Oregon, Washington, Utah, Montana, Arizona, and New Mexico and

[139] Duncan, D., *July 13, 2006 Directive of the Minister of Energy*, p.2.
[140] This will be discussed further in Section 5.3.4
[141] *Ibid.*p.2.
[142] This position was recently abolished as a result of the *Green Energy Act.*

the provinces of British Columbia, Manitoba, Ontario, and Quebec.[143] The WCI has the goal of reducing greenhouse gases 15% below 2005 levels by 2020.[144] As a tool to reach its goal, the WCI has proposed a cap and trade system which will begin operating in 2012. To harmonize with WCI's cap and trade system, the Ontario government adopted Bill 185, which clarified the regulation of emissions credits or instruments designed to fulfill a similar purpose.[145] Once the WCI cap and trade system begins operating, energy commodity prices will reflect, however imperfectly, the environmental cost of fossil-fueled central generating stations.

In the spring of 2009, the government of Ontario passed the *Green Energy and Green Economy Act, 2009* (the "Green Energy Act"). The Green Energy Act requires that energy audits be conducted and revealed to potential buyers before the sale of homes and buildings, that feed in tariffs ("FITs") be developed and implemented, that appliances meet certain energy efficiency requirements to be sold in Ontario, and that connection of distributed generation by transmission and distribution companies be made easier.[146] Schedule D of the Green Energy Act amends the Ontario Energy Board Act to allow the Energy Minister to order the OEB to set conservation targets for electricity distributors and to pass the costs of the programs administered by the MEI to ratepayers, incenting utilities to provide funding for energy efficiency upgrades that do not pay for themselves as quickly.

In December 2009, the MEI increased funding for the OPA's CDM programs by $50 million for 2010. The OPA is also revising its Integrated Power Systems Plan to reflect the changed electricity needs due to the Green Energy Act. The OPA expects conservation savings to increase by more than 40% by 2012.[147]

The FITs permitted by the *Green Energy Act* have been remarkably popular. There are two FIT programs: the microFIT program which includes renewable projects of 10 kW or less and the regular FIT which includes all other programs. The microFIT program resulted in more than 1,200 applications and 700 approvals to date, mostly projects that allow solar

[143] Numerous other US states, the provinces of Saskatchewan and Nova Scotia, and six northern Mexican states are observers of the WCI.
[144] Western Climate Initiative (2007). *Statement of Regional Goal*.
[145] Bill 185, Section 2.
[146] FITs are designed to stimulate buildout by providing the developer/owner a steady stream of income which is not solely based on the marginal costs of electricity generation.
[147] Ontario Power Authority (2009), 2010-2012 Business Plan. p. 14.

panels to be added to roof tops.[148] The FIT program has received approximately 1,000 applications for FIT contracts in two months.

Additional CDM policies are in the pipeline and will affect future CDM throughout Ontario. First, a revision to the building codes is underway which will continue the emphasis that exists on energy efficiency. Second, the Ontario government has proposed rebates for the purchase of electric vehicles of up to $10,000. The program would start in July 2010.[149] This policy would not lead to increased electricity conservation in Ontario and would slow the decline in average use, but would help Ontario reduce its greenhouse gas emissions. Third, the OPA is developing financial incentive programs that will encourage energy savings among large industrial consumers.

5.3.3 Use per Customer Trends

Volume per customer trends are provided in Table 5 for the aggregation of Ontario power distributors. Data are presented separately for residential customers and general service customers. The full sample period is 2002 to 2008. The volumes are not weather normalized. This, combined with the shortness of the sample, suggests that it is difficult to draw conclusions about the trends with much certainty.

Inspecting the results, it can be seen that average deliveries of power to residential customers of all power distributors declined by 2.58% annually from 2005 to 2008. Numbers for individual utilities deviate considerably from the industry trend and some utilities have increasing average residential customer use. Declines for the ten largest distributors in 2008 --- which accounted for more than 70% of all customers served in the province, --- are somewhat higher, averaging 2.68% per annum. The decline in the average residential customer use of the other utilities averaged 2.31% per annum. The discrepancy may reflect in part a tendency for larger distributors to pursue CDM more aggressively. For both groups of distributors, a considerable acceleration of the trend is evident in the later years of the sample period, but this could be due more to the factors and not an uptick in CDM.

Table 5 also shows that the delivery volume per *general service* customer in the distribution industry averaged a slight 0.16% average annual growth since 2005. Once again, growth in volume per customer was slower for the ten largest utilities, averaging a 0.37%

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[148] The total capacity for the microFIT applications is over 8 MW. The OPA estimates that this would power about 1,000 homes.
[149] The goal is to have 1 in 20 vehicles in Ontario be electric by 2020.

Table 5

Trends in Volume Per Customer of Ontario Power Distibutors

(kWh/Customer)

	All Companies				Ten Largest Companies				Other Companies			
	Residential		General Service		Residential		General Service		Residential		General Service	
Year	**Level**	**Growth Rate**	**Level**	**Growth Rate**	**Level**	**Growth Rate**	**Level**	**Growth Rate**	**Level**	**Growth Rate**	**Level**	**Growth Rate**
2002	10,276		137,899		10,503		141,685		9,726		129,519	
2003	10,445	1.64%	140,350	1.76%	10,225	-2.68%	144,662	2.08%	10,975	12.08%	130,702	0.91%
2004	10,073	-3.63%	141,279	0.66%	10,275	0.49%	144,964	0.21%	9,589	-13.50%	133,129	1.84%
2005	10,403	3.22%	145,919	3.23%	10,586	2.99%	153,441	5.68%	9,966	3.86%	129,500	-2.76%
2006	9,780	-6.18%	144,035	-1.30%	9,959	-6.11%	149,865	-2.36%	9,356	-6.32%	131,180	1.29%
2007	9,882	1.04%	149,678	3.84%	10,045	0.86%	155,856	3.92%	9,495	1.48%	136,139	3.71%
2008	9,629	-2.59%	146,642	-2.05%	9,768	-2.79%	151,727	-2.69%	9,297	-2.10%	135,456	-0.50%
Average Annual Growth Rates												
2002-2008		**-1.08%**		**1.02%**		**-1.21%**		**1.14%**		**-0.75%**		**0.75%**
2005-2008		**-2.58%**		**0.16%**		**-2.68%**		**-0.37%**		**-2.31%**		**1.50%**

Source: Tabulated by PEG Research from OEB data annual *decline* since 2005. The other utilities averaged 1.5% average annual *growth* in deliveries per customer. We are reluctant to draw firm conclusions from these data that there is a rising or falling trend in average delivery volumes to general service customers. Volume per customer is a crude metric in the general service sector as mentioned in Section 5.2.3 above.

To obtain supplemental evidence on volume/customer trends we perused some of the recent rate filings of larger distributors. We found that, from 2004 to 2008, Toronto Hydro averaged a 1.2% decline in the *weather-normalized* volume per customer of the residential class and a 2.9% decline in the volume per customer of the GS < 50 class.[150]

The numbers suggest that average use trends are already a potential source of earnings attrition for many Ontario power distributors between rate cases. Average use is declining in the class that typically accounts for the bulk of distribution base rate revenue. The decline in average use by residential customers is already comparable to that experienced by natural gas distributors. While there is no evidence of a *declining* trend for general service customers, an absence of any trend would mean that these customers provide no growth in average system use that can help distributors offset the impact on unit cost growth of the decline in average residential use.

5.3.4 Regulatory System

<u>General Features</u>

The OEB regulates electricity transmission and distribution companies using a combination of IR and periodic rate cases. The terms of distribution service are the chief focus of OEB distribution regulation. Recovery of transmission and power supply costs is ensured via variance accounts.

<u>Incentive Regulation</u>

Ontario implemented its first comprehensive price cap IR plan for electricity distributors in 2000. The plan had a three year term, from 2000 to 2002. However, before the plan could run its course, the Provincial government imposed a cap on overall retail electric prices. This cap effectively eliminated any further formula-based distribution price adjustments for distribution services and thus ended the plan.

[150] Toronto Hydro Electric System 2010 Revenue Requirements Application in OEB Case EB-2009-0139, Exhibit K1, Tab 3, Schedule 1 and Tab 6, Schedule 1.

In its 2005-06 business plan the Board announced a multi-year regulatory plan for the Ontario electricity distribution sector. As part of that plan in 2006 most electricity distributors had rates reset based on a review of their historical costs. In 2007 the Board approved a new incentive regulation plan (2nd generation IR) with a rate adjustment mechanism. That mechanism, which involves a price cap index, will be in effect over the period 2007 to 2010. Beginning in 2008, the Board divided distributor rate re-basing reviews into tranches to await rate rebasing. Distributors not rebased in any given year would have their rates adjusted by the second generation IR rate mechanism.

Building incrementally on the 2nd generation IR plan the 3rd generation IR plan, in effect over the period 2009 to 2013, is a price cap based on empirical research. Revenue decoupling was considered as an alternative but Staff recommended reliance on the current LRAM framework pending completion of the EB-2007-0031 consultation on power distribution rate design.

The basic structure of 3rd generation IR is a "core plan" and "modules". The core plan is a price cap plan and applies to all distributors. The X factor terms of each price cap index has two components, a "productivity factor" and a stretch factor.[151] [152] A 0.72% productivity factor was approved for all companies. This was the power distribution TFP trend, over the 1988-2006 period, of a large sample of U.S. electric utilities.[153] The TFP index used in this calculation featured an output index with multiple output measures weighted by cost elasticity shares. This approach to productivity measurement is discussed in Section 4.1 above and is noted there to focus on cost efficiency. Since, additionally, there is no separate provision in IRM3 for average use adjustments, the framework takes no account of the average use trends.

Productivity stretch factors vary by company. The sector is divided into three different efficiency cohorts based on OM&A benchmarking studies, with lower stretch factors for more efficient firms.[154] This tailors the X factor to reflect differences in

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[151] OEB, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673, September 2008.
[152] No adjustment was deemed warranted for the fact that the GDPIPI is an output price index that reflects the productivity trend of the Canadian economy.
[153] Lawrence Kaufmann *et al*, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Pacific Economics Group, February 2008, p. 56
[154] Efficiency was determined using benchmarking methods developed by PEG personnel

productive efficiency, while providing a foundation for more comprehensive (*i.e.* total cost) benchmarking in the future.

The “modules” are options that distributors can use, under some circumstances, and which can address their particular circumstances which may not be dealt with in the core plan. This basic structure attempts to balance application of sound incentive regulation principles and practicality so that the overall IR framework is rigorous and well-grounded, and yet flexible enough to accommodate differences in company circumstances.

The core IR mechanism creates incentives to control all costs, including capital expenditures, but the capital module can permit some additional capital expenditures because of differences in investment cycles, etc. However, the capital module: 1) only recovers expenditures the Board deems to be prudent, so efficiency is still promoted; and 2) only recovers expenditures in excess of a threshold designed to eliminate double counting of capex thru the core IR mechanism and the module. The design of this mechanism is unique and focused on ensuring that different regulatory objectives are promoted in a single IR plan and that different regulatory mechanisms work together effectively.

Distributors retain the right to file rate cases outside of the IR cycle and several have done so. These include large distributors like Toronto Hydro and Hydro One. This phenomenon reduces risk but raises regulatory cost and weakens utility performance incentives.

Rate Rebasings

Many distributors have used historic test years in their rate rebasing filings. Subsequent filings will in almost all cases involve forward test years. Load and revenue forecasts play an important role in FTY rate cases. As outlined in Chapter 2 of the Board’s Filing Requirements for Transmission and Distribution Applications, an applicant must provide its volume and revenue forecast, weather normalization methodology, and other sources of revenue in an exhibit. It must also provide an explanation of the causes, assumptions, and adjustments for the volume forecast. All economic assumptions and sources used in the preparation of the load and customer count forecast should be included (*e.g*. Housing Outlook & Forecasts, relative energy prices and other variables used in forecasting volumes).

The applicant must also provide an explanation of the weather normalization methodology and its application. The Board recognizes that an important aspect of any case is the uniqueness of the transmitter or distributor and the circumstances in which it operates. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather, and economies of each utility's market.

Two types of load forecasting models have generally been filed with the Board in cost of service applications. These are Multifactor Regression and Normalized Average use per Customer (NAC) models. Applicants are not restricted to filing one of these two models. Regardless of the model used by the applicant, the Board has identified in its guidelines certain information in relation to the applicant's model that is required by the Board.

Forecasting methodologies are perforce idiosyncratic since the drivers of volume growth vary substantially across the province. For example, heating degree days are a far more important volume driver for distributors in northern and western Ontario than in the south. Due in part to the recessionary conditions in the province, a number of distributors have recently refiled their volume forecasts during rate cases. Utilities have an incentive to underestimate volume per customer growth that is amplified by the multiyear price cap plans. Intervenors have the incentive to overstate volumes.

Utility CDM Activities

Some Ontario power distributors were involved in Ontario Hydro's CDM programs in the 1990s. CDM then took a back seat to the industry restructuring initiative for several years until distributor involvement in CDM was reauthorized by the *Electricity Restructuring Act, 2004.* Distributor CDM programs recommenced in 2005 and have continued to the present.

Over the period 2005 to 2007 distributors administered most "standard" CDM programs in Ontario. Since 2007 the OPA has, additionally, directly administered a number of province-wide CDM programs. Distributor programs that are not funded by the OPA may, with Board oversight, be funded by distribution rates.

Participation in CDM is still voluntary, and distributors have varied levels of involvement. The Green Energy Act authorizes the Energy Minister to set CDM targets for distributors. However, this provision of the Act has not yet been implemented.

The standard programs that distributors take the lead on administering in principle include consumer awareness and education programs, market capacity building, and market transformation programs. However, there has been little emphasis on market transformation to date, due in part to the limited impact that the many smaller distributors can have on CDM markets.

Increased distributor involvement in CDM raised a host of regulatory issues for the Board. In March 2007, the Board issued a Framework Report on its regulation of power distributor CDM.[155] Guidelines for distributor CDM filings were issued in March 2008.[156]

In its Framework Report, the Board enunciated certain principles guiding its regulation of CDM, including the following.

1. **Implementation of government policy should be facilitated.** Government policy includes … identifying and developing innovative strategies to accelerate the implementation of conservation, energy efficiency and demand management measures, including strategies to encourage and facilitate competitive market-based responses.
2. **Regulatory certainty and predictability should be provided.**
3. **Confusion in the CDM marketplace should be minimized.** The framework should ensure that the respective roles of all CDM … participants… are clearly defined…
4. **Administrative efficiency should be attained to minimize the regulatory burden to distributors, and costs to ratepayers, while maintaining transparency and thoroughness in regulatory process.** The framework should provide for processes that are as streamlined as possible.[157]

The Board considered in the framework proceeding a range of ideas for dealing with the financial effects of the slowdown in volume growth that would result from CDM. John Todd wrote a paper on behalf of the Electricity Distributors Association that recommended a revenue stabilization adjustment mechanism that broadly resembled the revenue true up mechanism of the same name that has been used for many years by Terasen Gas.[158] In this proceeding, the OPA stated that decoupling true up plans

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155 OEB, *Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2008 and Beyond*", March 2007.
156 OEB, *Guidelines for Electricity Distributor Conservation and Demand Management*, EB-2008-0037, March 2008.
157 OEB *op cit* p. 2.
158 John Todd, *Designing an Appropriate Lost Revenue Adjustment Mechanism* (*LRAM*) *for Electricity CDM Programs in Ontario*, Elenchus Research Associates, August 2006.

> [have] the benefit of removing any motivation for LDCs to be a barrier to CDM efforts in which they are not directly involved. There is a natural reluctance for LDCs to support activities that might have even a minimal financial cost. Risk-avoidance behavior by LDCs can become a barrier to all conservation efforts including, for example, naturally occurring conservation and those initiatives of retailers and other providers of CDM products and services.[159]

In its deferral of the revenue stabilization adjustment mechanism proposal, the OEB stated in its 2007 Framework Report that it

> has seen no evidence to date that distributors are experiencing any undue hardship due to revenue erosion. To date, the Board has received only one application for LRAM recovery. In addition, if distributors believe that the effects of third party CDM efforts have been inaccurately factored into their current distribution rates, distributors have the option of applying for early rebasing.[160]

The Board implemented an approach to decoupling that is similar to that used by Ontario gas distributors prior to their adoption of partial decoupling true up plans. LRAMs adjust base rates for any variance in the prior year between actual lost margins, resulting from energy savings produced by each distributors' CDM programs, and the lost margins that are reflected in base rates. The LRAM covers distributor programs funded by the OPA as well as those funded by distributor rates. The covered programs include those delivered for the distributor by a third party, as well as programs undertaken in partnership with other entities, such as natural gas utilities or community agencies. However, the utility shares credit for the outcomes of programs for which it cannot claim full attribution. Lost revenue from each service class is recovered from the customers in that class.

For CDM programs initiated in 2007 and later years, distributors are expected to provide an independent third party evaluation of program results when filing LRAM claims. For OPA funded programs, the scope of these evaluations should be limited to confirming that the participation level in the distributor service area is accurate and that energy savings

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[159] OPA Comments on the EDA Proposal for a Revenue Stabilization Mechanism for Local Electricity Distributors, 2006. OEB Docket EB-2006-0267. p.2

[160] OEB, *op cit* p. 10.

assumptions used in the calculation of the lost revenue amount are consistent with those used by the OPA.[161] CDM programs must pass a total resource cost ("TRC") test. The TRC test measures benefits and costs from a societal perspective but these calculations do not include the cost of environmental damage from power production and delivery. Distributors may file for plans of up to three years but this too is not mandatory.

Most Ontario distributors have not to date filed LRAM claims. The inherent difficulty of accurately quantifying the impact of CDM may be one reason.[162] Another is the cost of an LRAM filing. Many smaller Ontario distributors do not have a CDM specialist on staff, and an LRAM filing also requires a submission by an independent expert.[163] The expert can do all of the work but the charge for this service can be sizable for the smallest companies. Note, finally, that other features of Ontario distribution regulation reduce the immediate need for LRAM claims. These features include the use of forward test years in rate cases and the option to file a rate case or a Z factor claim.

LRAM claims that have been filed have focused almost exclusively on standard CDM programs. No company has to date filed a claim requesting lost margins from market transformation. There have been few requests for lost margins from jointly administered programs that do not qualify for 100% recovery by satisfying the centrality principle.

A supplemental incentive mechanism, called the shared savings mechanism ("SSM") is available for distributor CDM initiatives that are funded through distribution rates rather than the OPA. The distributor may recover 5% of the net benefits resulting from its CDM programs, where net benefits are calculated using the TRC test. For programs funded in 2007 and later years, distributors are expected to provide program evaluations that include results concerning program effects and cost effectiveness that have been reviewed by a third

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[161] Third party evaluation requirements relative to programs funded by distribution rates in 2007 and after are as follows: an opinion on the cost effectiveness results that are material to the LRAM amounts proposed; confirmation of the participation levels; confirmation that the energy savings assumptions used are those posted on the Board's website; the reasonableness of any savings assumptions used where they differ from those endorsed by the Board; recommendations on any forward looking evaluation work; and, recommendations for any improvements to the program regarding design, performance and customer participation."

[162] This is discussed in the OEB's Decisions with Reasons in Case EB-2007-0681, p.9.

[163] This requirement applies for distribution rate funded programs that commenced in 2007 or later. For LRAMs related to distribution rate funded programs prior to 2007 no third party review is required; for programs funded by the OPA, the OPA or its designate is considered an independent third party for the purposes of the filing. Some utilities may be following a strategy of filing LRAM claims less frequently than every year to accumulate savings to the point where the cost of a filing is warranted.

party.[164] Any supplemental compensation for performance under OPA contracts is the responsibility of that agency.

Rate Design

In 2007, the Board consulted with stakeholders on electricity distribution rate design. This review was intended to consider the need for, and approaches to, changes to distribution rate design in light of industry changes and emerging issues. The industry changes included the commercialization of electricity distributors and developments in metering, CDM, and LDG activities. In 2009, the Board decided to defer completion of the rate design project while staff conducts more research and expands the ability to model rate impacts. This may be for the best inasmuch as it is not yet clear how distribution rate design might best exploit the availability of the advanced metering infrastructure that is becoming available.

Rate designs for the small volume customers of some of the larger Ontario power distributors are provided in Tables 6 a through c. In 2008, the rate design for Hydro One's residential rate R1 featured a customer charge of about $18 and a flat 2.6 cent/kWh volumetric charge.[165] The customer charge accounted for a substantial 42% of the distribution revenue requirement. The rate design for Hydro One's general service rate GSe features a monthly customer charge of about $30 and a flat volumetric charge of about 3 cents. The customer charge accounted for about 32% of the revenue requirement.

In 2009, the rate design for Toronto Hydro residential service features a $16.85 customer charge and a flat 1.4 cent/kWh volumetric charge. The customer charge accounted for almost 62% of the distribution revenue requirement. The rate design for Toronto Hydro's small volume (<50 kW) commercial service features a $21.44 monthly customer charge and a flat 2.0 cent/kWh volumetric charge. The customer charge accounted for only about 26% of the revenue requirement.

[164] For distributor funded programs prior to 2007, no third party review is required.
[165] The customer charge for residential rate R2 was about $48.

Table 6a

Rates For Small-Volume Customers of Ontario Power Distributors

Hydro One Networks Residential Rate UR - Rates Effective for 2009

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	26,798	162,058	**$**	**13.780**	**44.8%**
Volumetric Charge	kWh	$	33,017	1,494,000,000	**$**	**0.022**	**55.2%**
Total Revenue		***$***	***59,815***				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	59,815	162,058	**$**	**30.758**	**100.0%**
Volumetric Charge	kWh	$	-	1,494,000,000	**$**	**-**	**0.0%**
Total Revenue		**$**	**59,815**				**100.0%**
Change in Monthly Customer Charge					**$**	**16.978**	

Hydro One Networks Residential Rate R1 - Rates Effective for 2008

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	82,754	376,430	**$**	**18.320**	**42.3%**
Volumetric Charge	kWh	$	112,819	4,407,000,000	**$**	**0.026**	**57.7%**
Total Revenue		**$**	**195,574**				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	195,574	376,430	**$**	**43.296**	**100.0%**
Volumetric Charge	kWh	$	-	4,407,000,000	**$**	**-**	**0.0%**
Total Revenue		**$**	**195,574**				**100.0%**
Change in Monthly Customer Charge					**$**	**24.976**	

Hydro One Networks Residential Rate R2 - Rates Effective for 2008

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	210,248	364,938	**$**	**48.010**	**55.6%**
Volumetric Charge	kWh	$	167,595	5,624,000,000	**$**	**0.030**	**44.4%**
Total Revenue		***$***	***377,843***				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	377,843	364,938	**$**	**86.280**	**100.0%**
Volumetric Charge	kWh	$	-	5,624,000,000	**$**	**-**	**0.0%**
Total Revenue		**$**	**377,843**				**100.0%**
Change in Monthly Customer Charge					**$**	**38.270**	

Difference between italicized number and Hydro One's number is due to rounding of volumes.

Source: EB-2008-0187, Hydro One Exhibit B2, Tab 1, Schedule 1

Table 6b

Rates For Small-Volume Customers of Ontario Power Distributors (cont'd)

Hydro One Networks General Service Rate GSe - Rates Effective for 2008

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	34,677	97,005	**$**	**29.790**	**31.6%**
Volumetric Charge	kWh	$	74,947	2,299,000,000	**$**	**0.033**	**68.4%**
Total Revenue		**$**	**109,625**				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	109,625	97,005	**$**	**94.174**	**100.0%**
Volumetric Charge	kWh	$	-	2,299,000,000	**$**	**-**	**0.0%**
Total Revenue		**$**	**109,625**				**100.0%**
Change in Monthly Customer Charge					**$**	**64.384**	

Hydro One Networks General Service Rate UGe - Rates Effective for 2008

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	1,814	12,744	**$**	**11.860**	**17.5%**
Volumetric Charge	kWh	$	8,522	424,000,000	**$**	**0.020**	**82.5%**
Total Revenue		**$**	**10,336**				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	10,336	12,744	**$**	**67.588**	**100.0%**
Volumetric Charge	kWh	$	-	424,000,000	**$**	**-**	**0.0%**
Total Revenue		**$**	**10,336**				**100.0%**
Change in Monthly Customer Charge					**$**	**55.728**	

Source: EB-2008-0187, Hydro One Exhibit B2, Tab 1, Schedule 1

Table 6c

Rates For Small-Volume Customers of Ontario Power Distributors (cont'd)

Toronto Hydro Electric System Residential - 2009 Board Approved Rates

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	*$*	*125,426*	611,808	**$**	**16.850**	**61.9%**
Volumetric Charge	kWh	$	77,145	5,387,207,866	**$**	**0.014**	**38.1%**
Total Revenue		**$**	**202,571**				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	202,571	611,808	**$**	**27.214**	**100.0%**
Volumetric Charge	kWh	$	-	5,387,207,866	**$**	**-**	**0.0%**
Total Revenue		**$**	**202,571**				**100.0%**
Change in Monthly Customer Charge					**$**	**10.364**	

Number in italics is $41 lower than applicable table due to rounding.

Toronto Hydro Electric System General Service <50 kW - 2009 Board Approved Rates

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	*$*	*17,193*	65,911	**$**	**21.440**	**25.5%**
Volumetric Charge	kWh	$	50,282	2,545,941,999	**$**	**0.020**	**74.5%**
Total Revenue		**$**	**67,475**				**100.0%**

Hypothetical SFV Pricing Scenario

	Billing Unit		Revenue Requirement ($000's)	Units		Price per Unit	Share of Revenue Requirement
Customer Charge	bills	$	67,475	65,911	**$**	**84.143**	**100.0%**
Volumetric Charge	kWh	$	-	2,545,941,999	**$**	**-**	**0.0%**
Total Revenue		**$**	**67,475**				**100.0%**
Change in Monthly Customer Charge					**$**	**62.703**	

Number in italics is $2 lower than applicable table due to rounding.

Source: EB-2009-0139, Toronto Hydro Electric System Exhibit K1, Tabs 1 - 6 and Exhibit O1, Tab 1, Schedule 1

Tables 6a-6c also show the hypothetical results that would be obtained with SFV pricing in the same rate years. For Hydro One, the monthly customer charge for residential rate R1 would rise from $18 to around $43. The monthly customer charge for general service rate GSe would rise from about $30 to about $94. For Toronto Hydro, the monthly customer charge for residential customers would rise from $16.85 to $27.21. The monthly customer charge for small general service customers would rise from about $21 to about $84.

5.3.5 Appraisal

Power distributors in Ontario appear to be facing business conditions that increasingly resemble those that faced provincial gas distributors several years ago. The government of Ontario is strongly committed to CDM. Distributors administer most CDM programs in the province. For many distributors, including some of the largest in the province, average use by residential customers appears to be declining materially and the trend in the average delivery volumes to general service customers does not appear to provide much if any counterbalancing relief. Expected changes in Ontario CDM policies are apt to cause these conditions to continue or intensify after the volume "bump" that will likely follow the end of the recession. The Board prefers multiyear rate plans for power distribution, but the price cap indexes are not designed to compensate distributors for declining average use. Since these plans involve annual rate adjustments for *cost* attrition, decoupling true up plans need not increase the frequency of rate adjustments if adjustments are made annually.

The current regulatory system can provide power distributors with considerable relief from the earnings attrition that can result from a worsening average use problem. LRAMs can compensate distributors for the demonstrated lost margins that result from their CDM programs. Some distributors have fairly high fixed charges for residential customers. Forward test years are now used in distribution rate rebasings. The shared savings mechanism provides additional compensation for CDM programs. Distributors can obtain supplemental relief from Z factor filings or new rate cases.[166]

[166] It may also be noted that revenue for recovery of the cost of transmission services purchased from Hydro One is already fully decoupled.

At issue is whether other approaches to decoupling make *more* sense for power distributors then this sensible system going forward. One salient alternative is partial decoupling true up plans, an approach now used by Ontario's gas utilities. The other salient alternatives are full decoupling and SFV pricing.

In reviewing the conditions that our analysis suggests matter most in choosing a decoupling approach, we find that they are similar to those facing Ontario gas utilities in many respects but also differ in some respects.

- As on the gas side, some of the slowdown in average use will likely be due to circumstances other than distributor CDM programs. These include CDM programs directly administered by the MEI and OPA and changes in federal and provincial building codes and appliance standards. LRAMs do not compensate the utilities for attrition from these conditions. However, it is not clear that these supplemental sources of declining average use are as powerful as the conditions (*e.g.* improved furnace efficiency) that have been prevalent in the gas industry.
- There are means, other than the conventional CDM programs that are the focus of LRAMs, by which power distributors can promote CDM goals. These include distribution rate designs with higher usage charges, market transformation initiatives, and joint ventures with gas utilities and other CDM service providers. The evidentiary guidelines for the LRAM may discourage claims of lost margins from initiatives like these. The high administrative cost of LRAMs is reflected in the fact that most distributors have not to date filed LRAM claims.
- With regard to rate design, we have noted that some of the larger power distributors have fixed charges that are fairly high and usage charges for residential customers that are correspondingly low. Ontario's bulk power market, like its gas market, has meanwhile not yet internalized the cost of environmental damage from commodity production and use. On the other hand, Ontario is moving much more aggressively than most states and provinces in North America to reduce its reliance on coal-fired generation. Participation in a cap and trade program may begin as early as 2012. These circumstances in principle reduces the need for "socially engineered" distribution rates. Moreover, some uses of energy, such as electric vehicles, involve net reductions in environmental damage

and a surge in electric vehicle demand could be a boon to Ontario's auto industry. High night time usage charges would discourage electric vehicle use.

Note also that AMI will soon be available for all customers in Ontario. There is therefore no need to use inverted block rates to simulate peak load pricing. On the other hand, AMI creates opportunities to experiment with peak load pricing of distribution (as well as transmission) services. This would be an aid in load management that should be welcome in Ontario but involves a risk of fixed cost recovery that is not well understood.

- There are far more power distributors in the province of Ontario than gas distributors. Any regulatory cost advantage that one approach to decoupling has over others should therefore carry considerable weight in choosing a decoupling strategy. We have seen that decoupling trueups and SFV pricing do have material regulatory cost advantages over LRAMs. On the other hand, some distributors have made use of the shared savings CDM incentive mechanisms that the Board permits. These have to date used energy savings calculations, although the role of such calculations may diminish in the future.
- The regulatory community of Ontario has the experience and technical expertise to design RAMs that provide sufficient relief from cost attrition between rate cases. This removes the concern that decoupling true up plans might, if applied to companies experiencing *growth* in average use, actually increase their earnings attrition and drive them in for more frequent rate rebasings. Furthermore, it is as straightforward to design a decoupling true up plan that can provide the basis for multiyear year rate plans as it is a price cap plan.

After considering these conditions, our analysis of decoupling in Chapter 2 and the discussion of experience in Section 3, it is our view that the Board should give strong consideration to moving beyond LRAMs to some form of decoupling true up plan or SFV pricing. Both of these alternatives would better advance the Board's principles, enunciated in its CDM Framework Report, that it facilitate government CDM policy, provide regulatory certainty and stability, and achieve administrative simplicity. Decoupling using either approach would be more effective and administrative cost would be lower than with LRAMs, although in both cases the gains may not be remarkably large.

- Distributors would have diminished disincentives to encourage CDM in ways that are not credited, only partially credited, and/or are only credited with difficulty under current LRAMs.
- Rate plans would provide more complete relief for earnings attrition between rate rebasings. This would encourage more distributors to operate under the third generation incentive ratemaking plan, reduce the likelihood of Z factor filings for declining average use, and permit the maintenance or extension of the long intervals between rate cases in future IR plans. The cost of distribution regulation in Ontario would be reduced thereby and distributors would have stronger cost containment incentives.
- The regulatory process can be simplified in other ways as well. LRAMs can be eliminated, and volume forecasts can play a reduced role in rate rebasings. By removing an important source of unit cost growth between an historic test year and the rate year, which provides much of the rationale for forward test years, it might be possible for some utilities to file rate cases using historic test years if the Board would value the resultant regulatory economy.
- Operating risk from the slowdown in volume growth, and possibly also from year to year demand fluctuations, would be reduced. The benefit of any reduction in capital cost could be shared with customers.

With respect to the best alternative approach, SFV pricing has the lowest administrative cost, and this is a major consideration in the regulation of about eighty power distributors. Distribution rates and bills would be more stable than under decoupling true up plans. Electric vehicle use would be easier to encourage. Fixed charges that vary in some rough fashion with historic customer use can avoid sharp increases in fixed charges for small volume customers.

On the other hand, SFV pricing restricts rate design in a way that encourages power purchases, including purchases in peak demand hours, and discourages LDG. The capability of AMI to achieve peak load pricing for distribution service would go unused. This attribute of SFV pricing seems inconsistent with the Board's commitment to do everything possible to facilitate provincial energy efficiency goals.

Between the two kinds of decoupling true up plans, we note that partial true up plans have the advantage of being already established in Ontario. Full decoupling plans have lower administrative costs since they don't require weather normalization and reduce the importance of volume forecasts in Ontario's forward-looking rate rebasings. On the other hand, full decoupling involves more rate destabilization.

The desirability of full decoupling in Ontario is greatly enhanced if the Board is interested in exploring the use of distribution rate designs to further CDM goals. Partial true ups reduce but do not fully remove the disincentive for rate design experimentation because distributors would still be vulnerable to weather-related demand fluctuations. However, weather-related demand fluctuations probably have less impact on the earnings of many Ontario power distributors than they do on those of Ontario gas utilities.

Our suggestions in the gas section regarding possible refinements to the partial decoupling true up plans used for gas utilities pertain to power distribution as well. LRAMs could be eliminated, with the true up mechanism relied on exclusively to address the lost margins from utility CDM initiatives. The simpler approach to volume forecasting in the Union plan is appealing given the larger number of power distributors. The Enbridge and Union approaches to RAM design are both workable.

The need to agree on a multiyear RAM was noted in Section 2.2.2 to be a significant barrier to the diffusion of decoupling true up plans in the States. This may be less of a problem in Ontario given the Board's commitment to incentive regulation and the accumulating experience of the provincial regulatory community with the design of multiyear rate plans. Redesign of the attrition relief mechanism --- currently a price cap index --- may be necessary but should not involve much controversy or additional work.

Consider, by way of illustration, the conversion of the present 3rd Generation price cap index to use as a RAM. As we noted in Section 5.3.4, the PCI in the 3rd Generation plan has a productivity factor that reflects only the cost efficiency trend of U.S. distributors. It is suitable, then, for use in the Union Gas approach to RAM design without modification. Should a revenue per customer index like the RAM of Enbridge be desired, only a small adjustment is needed to the productivity offset so that the number of customers served is the only output metric used in the productivity trend calculation. Since customer growth for the US power distribution sample used in the Kaufmann study averaged 1.61% over the full

1988-2006 sample period that the Board preferred, PEG Research estimates that the revised productivity offset would be approximately 1.61% (the *customer* growth trend) - 1.04% (the input quantity index trend) or 0.57%.[167][168] Reliance in a fourth generation IR plan on productivity trends of Ontario power distributors should not pose a problem for this general approach since, if anything, it would be simpler to use the number of customers served as the output index in such a study. For utilities that desire a more flexible approach to RAM design that accommodates their need for a capital spending surge, the stair step and hybrid approaches to revenue cap design that have been popular over the years in the States merit consideration.[169]

Should the Board decide to move in the direction of decoupling true up plans there are some issues that will merit further consideration. One is whether the approach should apply to all distributors or be a voluntary option. Mandatory decoupling would remove the CDM lost margin disincentive for all utilities. On the other hand, "pilot" decoupling plans for a few utilities would be a sensible first step. These would presumably involve utilities experiencing an especially pronounced slowdown in average use and/or those having a particular interest in experimental distribution rate designs and other kinds of unconventional CDM. If these decoupling plans are successful, more widespread implementation could be undertaken at the time that the fourth generation IR plan is developed.

Experimentation with decoupling true up plans would also require Board decisions on a host of design issues. These include the following.

- Scope of the decoupling plan (all customers, or just small volume customers?)
- Choice of baskets (one big basket, or separate baskets for residential and business customers?)
- Rate adjustment caps (hard caps, soft caps or no caps?)
- RAM design
    - Revenue cap or a Union Gas style price cap index?
    - If a revenue cap, an Enbridge-style revenue per customer index or hybrids that give distributors greater capital spending flexibility?

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[167] See Tables 9 and 10 in the Kaufmann *et al* report for details.
[168] OEB, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 2008, p. 12.
[169] This could result in multiple approaches to RAM design, but there may be multiple approaches to *price* cap design on the horizon should the Board wish to keep all distributors on IR plans.

APPENDIX: CREDENTIALS OF PEG RESEARCH

PEG Research LLC is a company in the Pacific Economics Group consortium which is active in the fields of alternative regulation ("Altreg") and statistical research on utility performance. Our practice is international in scope and has to date included projects in eleven countries. Work for a mix of utilities, regulators, and public agencies has given us a reputation for objectivity and dedication to economic science.

Senior Author Mark Newton Lowry is the President of PEG Research LLC. His duties in that capacity include the management of the company, the design of Altreg plans, supervision of statistical research, and expert witness testimony. He has testified numerous times on Altreg and utility performance issues. Venues for his testimony have included California, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New York, Vermont, Alberta, British Columbia, Ontario, and Quebec.

Revenue decoupling is one of Dr. Lowry's specialties. He has provided relevant testimony in proceedings leading to the approval of fourteen decoupling plans, including plans for BC Gas (d/b/a Terasen Gas), Central Vermont Public Service, Enbridge Gas Distribution, the Hawaiian Electric Companies, San Diego Gas and Electric, and Southern California Gas. He has published four articles that address decoupling issues.

Earlier in his career, Dr. Lowry worked for eight years at Christensen Associates, first as a senior economist and later as a Vice President. His career has also included work as an academic economist. He was an Assistant Professor of Mineral Economics at the Pennsylvania State University and a visiting professor at l'Ecole des Hautes Etudes Commerciales in Montreal.

In total, he has twenty nine years of experience as a practicing economist, spending the last twenty one years addressing utility issues. He holds a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin. He has served as a referee for several scholarly journals and has an extensive record of professional publications and public appearances.