ENERGY REGULATORS REGIONAL ASSOCIATION

Tariff and Pricing Committee

Issue Paper

ECONOMIC ISSUES RELATED TO TARIFF DEVELOPMENT

Prepared by

Pierce Atwood LLP

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1. Objective

Introduction

The objective of price regulation is to insert an administratively determined method of pricing a product for an industry where prices determined by the market will provide an economically inefficient and socially unacceptable outcome. These markets are uncompetitive and will not lead to a socially desirable allocation of resources when left to their own devices. Therefore, the development of tariffs is one of the most critical activities in the regulatory function.

The Energy Regulators Regional Association (ERRA) has retained Pierce Atwood to prepare an issue paper addressing electric power regulation. The principal objective of this paper is to provide a concise guiding document concerning tariff setting methodologies for ERRA members and staff.

Organization of Report

This report is organized as follows:

Chapter 2 discusses the Principles of Tariff Setting and Tariff Regulation.

Chapter 3 addresses the issue of Regulation as a Substitute for Competition.

Chapter 4 describes the Elements of the Revenue Requirement.

Chapter 5 provides the arguments of why a utility requires an adequate Rate of Return.

Chapter 6 provides a theoretical and practical discussion of Estimating the Rate of Return.

Chapter 7 discusses Pricing Design.

Chapter 8 speaks to the issue of Revenue Allocation.

Chapter 9 provides a discussion of Demand Forecasts and Load Research in the Electric Power Sector and its importance to the regulatory process.

Chapter 10 provides a discussion of Price and Rate Cap Regulation.

Chapter 11 describes the role of Demand Side Management Using Pricing Techniques.

Finally, **Chapter 12** provides a brief reference to Game Theory as a Tool for Regulators.

2. Principles of Tariff Setting and Tariff Regulation

The Goals of Regulation

The principles of establishing tariffs are rooted in the dual goals of: (1) Providing the regulated (monopoly) supplier with sufficient revenue stream to operate the utility in a safe and efficient manner; and (2) Providing service to customers at a level and quality of service which they desire at the lowest possible cost.

To provide a context for the goal of providing the utility with a revenue stream sufficient to operate in a safe and reliable manner it is helpful to understand the concept of an economic profit. An economic profit exists when the revenues received exceed the opportunity costs incurred. Opportunity costs are used in order to take into account any alternative uses of the investment. Therefore, an economic profit occurs when the return on a specific investment exceeds the market return for an investment with equivalent risk and term. An economic profit differs from an accounting profit in that the accounting profit does not take into account any alternative use of the investment. Therefore, it is typical for a firm to have an accounting profit while simultaneously having no economic profit or loss.

Under economic theory, customers are provided with the quantity and level of service they desire when the price is set at the marginal cost to provide that service. The price would include all costs associated with the production of the commodity, both private and social. If the price is set at marginal cost, customers will demand (i.e. purchase) the economically efficient quantity of that commodity.

In summary, the goals of regulation can be summarized as follows:

1) Encourage the management of the utility to operate the enterprise in an efficient manner;
2) Provide guidelines for the utility to provide for the safety of the customers and the employees of the utility;
3) Establish standards for a level of reliability that is desired by the community;
4) Charge different customer classes prices that are both economically and socially justified; and
5) Provide the utility with a return that is justified by the level of risk.

The Process of Regulation

In this paper significant discussion is devoted to approaches and methods used to design tariffs. These approaches and methods are presented in a manner that might suggest that regulation can be implemented as a mechanical process.

In fact, however, effective regulation is not the product of a “mechanical” process that follows a set of steps leading inexorably to a reasonable and effective solution. Virtually every step in the design of tariffs requires a significant amount of judgment and subjective consideration. Furthermore, many of the steps in the regulatory process are interdependent and cannot be evaluated in isolation.

However, the accuracy of the input data should also be considered when designing tariffs. Many of the individual processes used in tariff design are performed using data samples, “snap shots” of the of financial performance of the utility at a specific period in time, and, in the cases of developing economies, accounting records that may rely upon restatements and estimates. The regulator must consider that the outputs various analyses have different levels of accuracy.

Put another way, the formulas and other tools used by regulators in setting tariffs cannot entirely replace the exercise of sound judgment and experience. These tools are necessary but not in themselves sufficient guides for regulators in establishing tariff rates that will balance the legitimate interests of utilities and their customers.

3. Regulation as a Substitute for Competition

The principal objective of modern regulation is to emulate the behavior of competitive markets. A properly functioning competitive market provides the most efficient allocation of resources and the lowest cost to consumers.

Behavior of Competitive Markets

If a market is competitive price regulation is unnecessary. Any change in the allocation of resources in a competitive market will reduce economic efficiency. In a competitive market internal forces of supply and demand will provide the discipline to suppliers and customers that is required to ensure that a socially optimal quantity of a product will be produced at a price that is economically efficient.

Competitive Pricing and Consumer Welfare

Perfect competition is the benchmark of economic efficiency in a capitalist economy. Under a perfectly competitive market economic efficiency is maximized and no one seller or buyer has influence over the price of the commodity. In other words no market participant can make itself better off by altering its behavior (i.e. either produce more or less of a commodity). The marginal cost of the commodity desired exactly equals the marginal utility of the consumer.

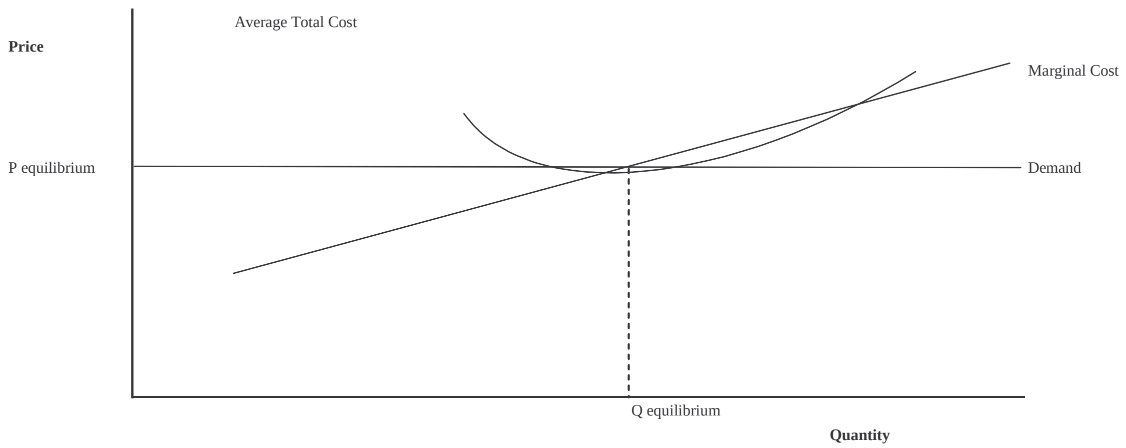

Figure 1 - Long-Run Equilibrium of a Firm in a Perfectly Competitive Market

Equilibrium in a competitive market contains the following attributes:

Any increase or decrease in the quantity will increase the Average Total Cost – The equilibrium quantity in a competitive market occurs where Average Total Cost (ATC) is minimized. Therefore, any increase or decrease in production will trigger an increase in ATC.

At Equilibrium Quantity Price = Marginal Cost = Marginal Revenue – At this point Marginal Cost equals Marginal Revenue. Any increase the quantity will produce a condition where the marginal costs exceed the revenues received from that increase in production thus reducing the profitability of the suppliers. Conversely, a decrease in the quantity will result in a decrease in revenue that exceeds the decrease in the costs incurred by the firms supplying the product and thus reducing profitability.

Behavior of a Monopolistic Market

Under a monopolistic market the quantity supplied by the monopolist is reduced because the monopolist is facing the demand curve for the market (downward sloping) and therefore will receive a lower price for every unit of output it produces. Therefore, the monopolist has an incentive to produce a socially inefficient level of output.

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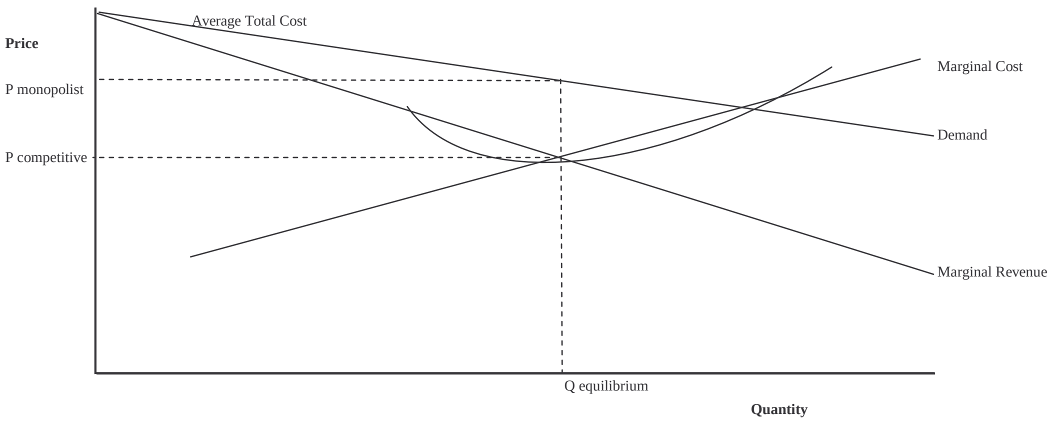

Figure 1 - Long-Run Equilibrium in a Monopolistic Market

The difference between the market faced by a monopolist and a competitive supplier is summarized below:

1) A competitive supplier faces the same prices regardless of the quantity supplied to the market, whereas the monopolist faces the demand curve for the entire market. The demand curve for the entire market (i.e. the demand curve faced by the monopolist) is generally downward sloping and thus the monopolist can influence the equilibrium price by changing the quantity supplied;
2) The Marginal Revenue of a monopolist will be downward sloping as opposed to the marginal revenue of a firm facing perfect competition, which is flat;
3) The monopolist has the ability to price discriminate between different customers or customer groups. In this context price discrimination means charging a difference price that is not cost or otherwise justified; and

4) The monopolist will produce a quantity where Marginal Cost equals Marginal Revenue like a competitive firm. However, that quantity will result in a price that exceeds Marginal Cost.

Natural Monopolies

A discussion of tariff design and regulation requires a discussion of natural monopoly. One of the primary arguments for price regulation is the existence of natural monopolies.

The Organization of Economic Co-operation and Development defines a natural monopoly as follows:

> A natural monopoly exists in a particular market if a single firm can serve that market at lower cost than any combination of two or more firms. Natural monopoly arises out of the properties of productive technology, often in association with market demand, and not from the activities of governments or rivals. Generally speaking, natural monopolies are characterized by steeply declining long-run average and marginal-cost curves such that there is room for only one firm to fully exploit available economies of scale and supply the market.[1]

Figure 3 illustrates the behavior of a natural monopoly.

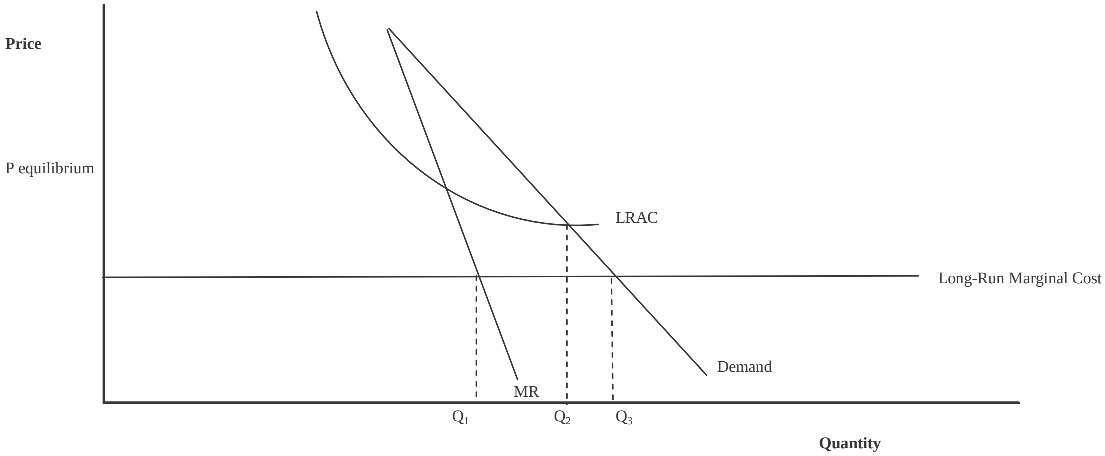

Figure 3 - Behavior of a Natural Monopoly

A natural monopoly is defined as an industry where a high ratio of fixed to variable costs exists. Significant economies of scope (i.e. it is cheaper to produce two commodities jointly as opposed to one commodity) and economies of scale (i.e. the average cost per unit decreases as the scale of output increases) exist.

[1] OECD, Glossary of Statistical Terms, http://stats.oecd.org/glossary/detail.asp?ID=3267

Figure 3 illustrates the specific behavior associated with a natural monopoly. If the natural monopoly produces a quantity that is normally considered socially efficient, where LRMC equals Price – Q3, it will be producing below that firm's average cost. This condition is clearly not sustainable because the firm would be sustaining a loss in the long-term. The monopolist has an incentive to produce where marginal revenues equal marginal costs at Q1. The objective of the regulator is to set prices that produce Q2, the price where the monopolist recovers its costs and earns a "normal" return.

The extreme example of natural monopolies was the telecommunications industry before mobile phones, Voice over Internet Protocol and other competitors. The cost to provide service to a specific market was largely fixed and the associated variable costs relatively small. The Average Total Cost of the commodity decreased rapidly as the quantity demanded increased.

When Can Regulation End for an Industry or Product?

In the past several decades the definition of what products in the utility industry should be regulated has changed. Traditionally the industry was vertically integrated and all products delivered or produced by the utility were regulated or government owned.

Over time a merchant market has been introduced for traditional utility products, and private ownership of portions of the energy infrastructure has increased. For example, in the electric power industry generation products are considered competitive products. The advent of Independent Power Producers (IPP) and the introduction of competitive retail generation suppliers have removed this product from the category of utility products that require regulatory oversight. The discipline of the market in effect "regulates" the pricing of generation products.

Some reasons for the change in what products are regulated and what products are not regulated are provided below:

1) Technological Change – changes in technology allow for some products of a vertically integrated utility to be unbundled and offered by competitive suppliers. The telecommunications industry is an excellent example of technological change that allowed certain products to escape from the definition of "natural monopoly;"
1) Innovations in Financial markets – financial markets have evolved significantly and are offering a wider variety of products to a larger group of customers. This has enabled the development of the IPP market through providing developers with a mechanism to finance new projects; and
2) Changes in Institutions – institutional change has enabled industries that were previously vertically integrated to separate into regulated and unregulated segments. For example, the introduction of open-access rules for the electric transmission function has enables the development of the merchant generation market. Lack of access to the "super-highway" of the electric power grid would hold these investments captive to the local utility.

4. Elements of Cost of Service Tariff Setting – the Revenue Requirement

The Goal of the Revenue Requirement

The goal of the revenue requirement is to provide the utility with the ability to earn a sufficient return in order to attract capital. The revenue requirement concept is entirely consistent with the economic concept that a utility should not earn an economic profit; recall that "economic profit" as used here refers to profit in excess of the return required for investment, or in excess of opportunity cost. Stated another way, a properly calculated revenue requirement will provide the utility with a zero economic profit.

Determining the Revenue Requirement

The utility revenue requirement is composed of the operating expenses and the return component. The revenue requirement equation is shown below:

Revenue Requirement = Operating Expenses + Return

The expenses of the utility will include the following:

1) Operations Expenses;
2) Maintenance Expenses;
3) Depreciation Expense;
4) Overhead Expenses (e.g. Administrative and General Expenses).

The equation defining the return of the utility is provided below:

Return = Rate Base * Rate of Return

The rate base is composed of the assets required to operate the utility in a safe and efficient manner. The components of rate base include Net Plant in Service, Net Intangible Assets and Working Capital.

Net Plant in Service – Net Plant in Service is the original book value of the utility long-term assets (i.e. plant and equipment) adjusted for Accumulated Depreciation.

Net Intangible Assets – Net Intangible Assets is the unamortized balance of Intangible Assets. Intangible Assets are assets such as a patent, goodwill, or a mining claim that has no physical properties.

Rate of Return – The Rate of Return (ROR) of the utility is the weighted average cost of capital. The ROR consists of the Debt Return and the Equity Return and is discussed in detail later in this paper.

The Role of Prudent and Reasonable Costs

When the revenue requirement is calculated the regulator often performs tests to determine if the components of the revenue requirement, both rate base and expenses, are reasonable. This is referred to as a prudency test. Only prudent costs are allowed into the revenue requirement calculation. Costs that are determined to be imprudent are excluded.

One approach to determining whether a component of rate base or an expense is prudent is to examine the decision making process behind the utility's action. The question that the regulator must examine is whether the decision making process was reasonable even if the outcome of the decision was detrimental to customers. For example, consider the example where the utility made a very significant investment in a pump storage hydroelectric project. The economic justification of this project was predicated upon a significant differential in market prices between on-peak and off-peak hours. However, due to events in the global energy market the actual prices of power plant fuels were significantly different from the forecasts used in the analysis and the investment in the pumped storage hydroelectric plant did not yield the savings predicted in the analysis the utility used to justify the investment to the regulator. In fact, the tariffs of the customer would have been lower in the long-run if the investment had not been made.

The outcome of this investment is clearly negative. In making a decision regarding the prudency of this investment the following questions must be answered:

1) Was the decision-making process used to justify the construction of the plant reasonable and professionally rigorous?
2) Did any significant flaws exist in either the analytical process or the mechanics to produce the analysis?
3) Did the utility have a vested interest in the outcome of the analysis?

If a negative response can be provided to the above questions the decision can generally be determined to be prudent. The underlying issue is not whether the outcome of the decision was beneficial or harmful to customers, but whether the process that led to the decision was reasonable. Put another way, the question is whether the decision by the utility a reasonable one for the utility to have made at the time, with the information available at the time.

The Rate of Depreciation

The rate of depreciation assigned to a utility's assets is an important but often a contentious issue in a utility rate case. The rate of depreciation impacts the revenue requirement in two ways:

1) The Depreciation Expense is a component of the expenses included in the revenue requirement. An increase/decrease in the Depreciation Expense typically increases/decreases the revenue requirement on a dollar-for dollar basis.
2) The Depreciation Expense of the utility directly impacts the Accumulated Depreciation. A rate of depreciation that is faster/slower than another approach will decrease/increase the Rate Base for a specific year thus impacting the return component.

The critical question becomes what is the proper level of depreciation of a certain asset or class of assets. The answer is tied to the physical or economic usefulness of that asset or class of assets. The rate of depreciation should be the periodic cost assigned for the reduction in usefulness and value of a long-term asset.

The utility will generally base its depreciation rates on studies of the economic or physical lives of the asset or group of assets. The regulator has the responsibility to ensure that these studies are accurate, and do not distort the depreciation rates in a way that would increase expenses (by using lives that are shorter than the economic of physical lives of the assets) or are too low to provide sufficient recovery of the cost of the asset to ensure that the utility has sufficient funds to replace the assets when required. As a practical matter, utilities are far more likely to ask for shorter lives in order to improve their cash flow.

Utilities and regulators may also use depreciation rates that are mandated or allowed by tax authorities. While this approach provides a degree of consistency and ease of accounting, there are circumstances where the use of tax depreciation rates does not provide a good match between the economic cost of providing service and the regulated price. For example, where the tax authority permits accelerated depreciation in order to stimulate investment (by lowering taxes in the early part of the life of an asset), it may be a better "match" between cost and price for regulatory purposes to use "straight line" depreciation.

Regulators may also be faced with issues relating to changes in technology and markets that alter the economic lives of assets after the initial determination of the lives has been made. For example, a new technology might accelerate the obsolescence of a group of assets. In that case, the regulator will need to consider the use of "remaining life" depreciation, in effect allowing recovery of the cost of the asset over the "remaining" time during which the asset will have economic value. Because the use of "remaining life" depreciation can lead to significant increase in depreciation expense, regulators must ensure that there is clear evidence supporting a change in the "useful life" of an asset.

5. The Rate of Return

The traditional form of price regulation addresses the Rate of Return of the utility. The goal of Rate of Return Regulation is to provide the utility with a return that is "normal" for a utility operating under the specific economic, technical and legal circumstances of the utility involved. Stated another way, the goal of regulation is to establish a level of profitability for the utility that provides no economic profit or loss.

While other forms of regulation have evolved since the introduction of Rate of Return Regulation many of the alternatives still require the calculation of a "normal" return as the foundation of the tariff setting process.

The Relationship Between the Opportunity for Cost Recovery and Investment

One of the goals of regulation is to establish an environment where a competently managed utility can attract the financial capital required to finance the investments that are required to operate the utility in a safe and efficient manner. A necessary condition of creating an environment where the utility has the opportunity to attract financial capital is to provide the utility with the ability to earn a fair rate of return. One definition of a fair rate of return was offered by U.S. Supreme Court Justice William O. Douglas in the seminal case Federal Power Commission v. Hope Natural Gas Company:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. …. By that standard the return to that equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[2]

While this is a case interpreting United States Constitutional law, the principles articulated there are the central principles applied to regulation throughout the world. In a sense, they are an articulation of the basic economic underpinning of the regulation of infrastructure industries. The keys issues Justice Douglas identified in the opinion in this case survive today and are critical to our thinking about establishing the rate of return for a utility are:

1) Capital investments require a return;
2) The return must compensate not only the debt of the firm but also the equity;
3) The equity return should be established at a level equal to investments on similar risk; and
4) The ultimate goal is to provide a return sufficient to attract capital and maintain the credit quality of the enterprise.

[2] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944) (Douglas, J.)

The Role of Financial Markets

Global financial markets have become increasingly competitive over time as the barriers for capital movement across international frontiers has been removed. For example, the evolution of the European Union from a tariff union to an integrated macroeconomic system has facilitated the movement of capital across international borders and reduced transaction cost. Therefore, a regulator can be relatively confident that the return demanded by the global financial market is reasonable when taking into account the conditions of the utility.

Competition between lenders and borrowers has become very competitive and sophisticated. It is therefore very critical that regulators provide a utility with a return that allows them to attract capital in competitive financial markets.

The return that the market requires for a specific utility receives is driven by the following factors:

1) The level of business risk;
2) Overall macroeconomic conditions; and
3) Specific characteristics associated with the market in which they exist.

You Can Invite, But Not Compel, Capital

Financial markets cannot be "compelled" into providing capital to utilities. Past initiatives that have attempted to do so have generally damaged the financial system of the country. The regulator has an important role in establishing an environment where a properly managed utility can attract capital in financial markets.

Certain key areas of a public utility's business environment can be influenced by the regulator. One area where a regulator can influence the business environment of the utility is to minimize regulatory risk and uncertainty. A regulatory policy that is unpredictable over time and inconsistent will be viewed by financial markets as being riskier and would therefore command a premium to the return. In contrast, the same utility facing a regulator that is consistent and predictable will face less risk and therefore require a lower return.

In stating that the regulator should be predictable over time we are not suggesting that a regulator should be "accommodating" to the utility, i.e. granting the utility everything it asks for or accepting all utility statements as true without verifying them. The goal of regulation is served by competence, reasonableness, and consistency, not accommodation. The utility, the customer and the financial community must be able to reasonably understand and anticipate the consequences of investment decisions.

Many factors associated with the business environment in which a utility operates are not controllable by the regulator. For example, a regulator has no impact on macroeconomic conditions or the behavior of international financial markets. These issues are driven by external forces. Within the regulatory body's sphere of influence, however, the regulator should do all it can to create the appropriate conditions to attract the necessary capital.

A Note on Capital Markets

The general consensus of modern thinking in finance is that capital markets are efficient. In this context efficiency means that the price of a security reflects all available information. The efficient market hypothesis has two implications for investors:[3]

> Because all information is reflected in the price of a security immediately the investor should only expect to receive a normal return.
>
> Firms should expect to receive the fair value of securities they sell.

A market becomes efficient through the transmission of information. If information is quickly available at little or no cost the arbitrage opportunities available to a security quickly disappear – in fact they may disappear instantaneously.

[3] Ross, Stephen A., Randooph Westerman and Jeremy Jaffe, Corporate Finance, p. 319

6. Estimating the Rate of Return

The Rate of Return (ROR) is the Weighted Average Cost of Capital (WACC) of the utility. Returning to earlier discussion, the WACC is the overall ROR of the utility that provides the utility with a return that is “normal” in an economic sense (i.e. the utility does not earn an economic profit or sustain an economic loss).

Typically the utility has two components to the weighted average cost of capital – debt and equity. Equation defining the ROR is provided below:

$$\mathbf{WACC = [(B / B+S) * r_B] + [(S / B+S) * r_S]}$$

Where

WACC is the Weighted Average Cost of Capital for the Utility
r_B is the cost of debt
r_S is the cost of equity
B is the value of the debt
S is the value of the equity

Estimating the Cost of Debt

The debt component is typically the weighted average cost of debt outstanding for the utility. Sometimes the market cost of debt is used in lieu of the weighted average cost of debt, especially if the utility is a newly privatized entity.
Approaches to Estimating the ROE

The equity return is the Return on Equity (ROE) estimated for the firm. These estimates are based upon the level of risk the firm faces compared to peer investments available in the financial market.

A number of theoretical approaches to estimating the ROE exist. The one element they have in common is they all require data from similar firms in order to estimate the market ROE for a firm with those characteristics. Therefore, regulators must be careful to examine data from a sample of firms that truly are representative of the utility being examined. If the sample includes firms that are significantly riskier than the utility in question the resulting ROE will be overstated and the utility tariffs will over-recover reasonable costs. Conversely, if the sample includes firms that are significantly safer the utility will under-recover costs and face challenges attracting capital.

There is a debate within the financial and economic community regarding what approach to estimating ROE is appropriate. A number of arguments can be made as to why different models may or may not be appropriate in a given situation but the most persuasive argument is that financial markets continually evolve. The evolution of financial markets will introduce new environments which in turn will promote new approaches to estimating the ROE of a firm. Therefore even where a regulator uses one method as the principal determinant of ROE, it should examine the results of other methods to help confirm the result as a basis for adjusting the result of the principal method.

The commonly used approaches to estimate ROE are discussed below.

Capital Asset Pricing Model

The Capital Asset Pricing Model (CAPM) defined as follows:

k = Rf + B(Rm-Rf)

where

k = The cost of equity capital
Rf = The risk-free rate of return
B = Beta, the relative correlation between the market and the security of the utility
Rm = The market return
(Rm-Rf) = The market return in excess of the risk-free rate.

For a utility, the investors' required rate of return is the risk-free rate plus the value of the non-diversifiable risk that investors assume by investing in the utility. Non-diversifiable risk is essentially the risk that is inherent in the marketplace. The beta coefficient measures the amount of this non-diversifiable risk, also called market risk, which investors are exposed to through their investment.

Implicit in the assumption behind the CAPM is the assumption that β is linear (i.e. the relationship between risk and return is perfectly linear).

Discounted Cash Flow

The DCF model is based on two fundamental financial principles:

(1) The current market price of a financial asset, such as a share of common stock or equity, is equal to the present value of all future cash flows that investors expect to receive from the asset. All cash flows to investors come from either future dividends or the sale of the stock. This means that the rate of return investors require for the risk they take in their investment is the rate at which the present value of all future cash flows from an asset are equivalent to the current market price of the asset; and
(2) The concept of the time value of money. In its most basic form, this principle provides that a dollar received today is more valuable than a dollar received at some point in the future. The present value of a dollar received today is higher because an investor could realize a return in future periods by investing that same dollar today. If the investor receives that dollar in the future, he or she will have missed the opportunity to invest today. Thus, the present value of the dollar received at some point further in the future is lower. The investor's required rate of return, or a company's cost of capital, is the rate of return that makes the present value of a dollar received today equal to the present value of a dollar received at some point in the future.

The equation for the DCF model is provided below:

k = D0(1+g)/ P0 + g

where

k = Investor's required "rate of return", or the "cost of equity capital"
D0 = The current dividend payment
P0 = The current stock price

$D0(1+g)/P0$ = The expected dividend yield
g = The expected sustainable growth rate

Risk Premium Approach[4]

The higher the perceived risk of an investment, the higher will be the return that investors require from that investment. If two investments offer the same expected return but have differing risks, investors will prefer the investment with lesser risk. Investors do so because they are said to be risk averse—***i.e.***, they prefer to take on less risk, rather than more risk, other things being equal.

It is nearly universally agreed that investors require a higher rate of return for an investment in the common equity for a particular company than they do in its debt. This is so for two important reasons. First, if an enterprise fails, debt holders have priority over equity holders as to the remaining assets of the company. Second, for an ongoing business, debt holders must be paid their contractual level of interest before equity holders can receive anything. Because of this basic fact, companies may reduce their dividend payments to equity holders when under financial strain. The cessation of payments to debt holders is a much rarer occurrence and will usually result in bankruptcy, unless corrected. In summary, debt is thought to be less risky than equity because debt holders have priority over equity holders as to: (1) distribution of assets in the case of dissolution of the company and (2) distribution of earnings in the case of everyday operations. Because equity holders "take second," they require a higher return than do debt holders. In order to be induced to choose a higher risk investment, an investor would have to be offered an expectation of some increment in return—a premium—for incurring additional risk. This incremental return is often known as the "risk premium" and it reflects the additional return that investors require to invest in common equity rather than debt.

The cost of equity is not directly observable, but must be estimated using inferences and judgment. In contrast, a bond yield is observable and if we know, or can estimate, the risk premium that common equity investors require to invest in common equity rather than debt, we can employ the risk premium approach to estimate the cost of common equity. As a general principal, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks and at the same time should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. A company therefore should be permitted to earn a return far enough above investments of lesser risk to be able to attract capital.

In general, the equity risk premium can be expressed in the following manner:

RP = Ke - Kd

The above equation implies that the equity risk premium is equal to the required return on equity (K_e) minus the required return on debt (K_d).

The issues that commonly face a regulator applying the risk premium method are the selection of the debt rate (i.e. what is the appropriate "risk free" rate), and how the level of the premium can best be measured (e.g. over what time period, and what equity returns should be examined).

[4] The description of Risk Premium is adapted from the public testimony of Robert Rosenberg in a utility proceeding in Maine, United States, submitted in 2007.

Capital Structures

The final variable in determining the ROR is the capital structure of the utility. The definition of capital structure is the mix of debt and equity used to finance the utility which was detailed previously in Equation 3.

In general, the more debt which is used to finance the utility the riskier the firm will be. Therefore, a firm that has a higher percentage of debt in the capital structure (higher leverage) will be riskier and require a higher overall return.

The seminal work on this topic was performed by Franco Modigliani and Merton Miller.[5] Modigliani and Miller addressed the issue of the choice between debt and equity and concluded the following:

Modigliani Miller Theory – No Income Taxes
A firm that exists in an economy without income taxes cannot change the value of its outstanding securities by changing the level of leverage in the capital structure. In other words, any capital structure for a specific firm will provide for the same weighted average cost of capital. The following formula provides this relationship:

$$\mathbf{r_S = r_0 + B/S(r_0 - r_B)}$$

where
r_B The Cost of Debt
r_S The Cost of Equity
B Is the value of debt
S Is the value of Equity
r_0 The Cost of Equity for an Unlevered Firm

The firm's ROE is a linear function of the debt to equity ratio. Therefore, the relationship between the capital structure and the cost of equity is illustrated in Figure 4 below:

[5] Modigliani, F. and M. Miller, "The Cost of Capital, Corporate Finance and the Theory of Investment", American Economic Review, June 1958.

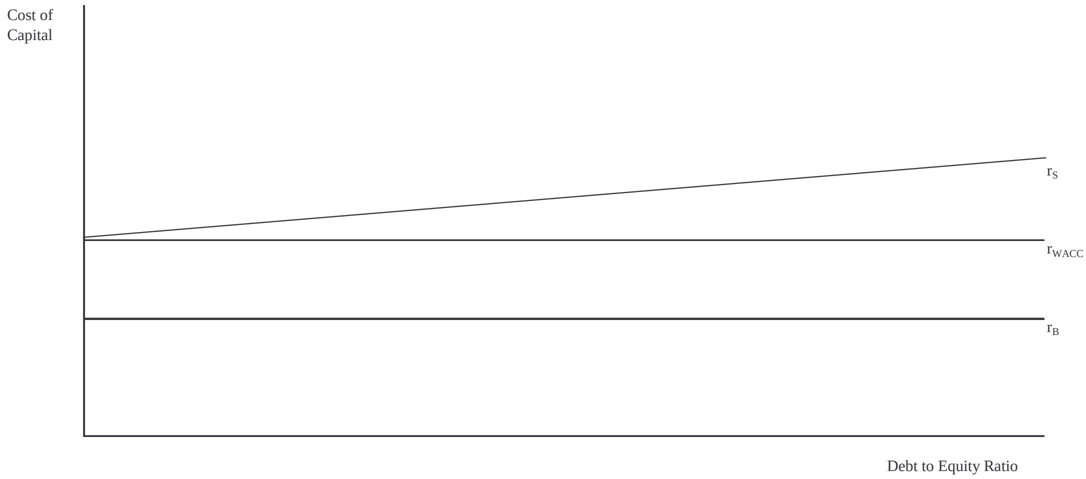

Figure 4 - Modigliani Miller Theory - No Taxes

In other words, as the leverage of the firm increases the cost of equity also increases resulting in a WACC that is constant.

Modigliani Miller Theory – With Income Taxes

A firm that exists in an economy with taxes (i.e. the interest expense from debt is a deduction from corporate income taxes) will find that a higher level of leverage will provide a lower WACC due to the income tax advantage provided to debt. The equation for calculating the WACC with income taxes is shown below:

$$\mathbf{VL = [EBIT * (1\text{-}T_C)/r_0] + T_C{}^r}$$

The implication is that although the level of debt used to finance the capital structure will trigger an increase in the ROE the tax shield provided to debt will provide the firm with a lower cost of capital.

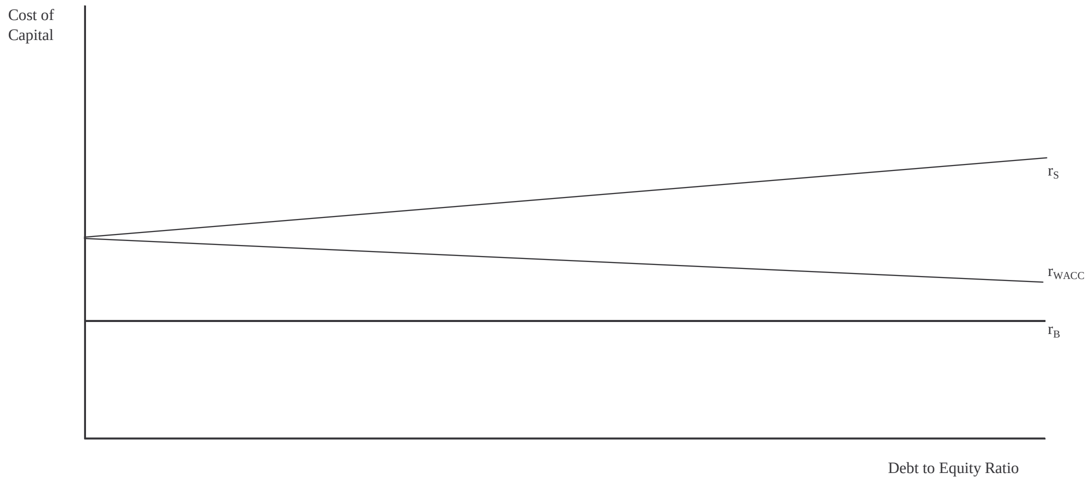

Figure 5 - The Effect of Adding Leverage Given the Impact of Income Taxes

Limits to the Use of Debt - The Costs of Financial Distress

An implication to Miller-Modigliani Theory when taxes are taken into account is that a firm has an incentive to continue increasing leverage, i.e. increasing the percentage of debt in its capital structure. However, a limit to the level of leverage that could exist with a firm exists because of the cost of Financial Distress.

Financial Distress costs are associated with bankruptcy, the threat of bankruptcy impairing the ability of the firm to conduct business and agency costs (i.e. conflicts between the interest of the shareholders and bondholders). The effect of Financial Distress costs is to provide a diminishing return to financial advantage of adding debt to the capital structure of a firm.

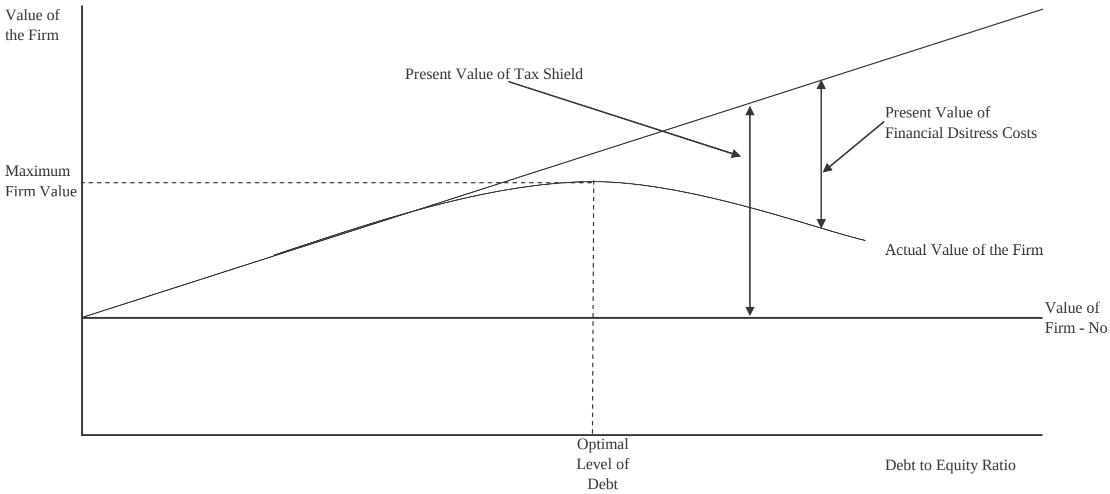

Figure 6 - The Optimal Amount of Debt and the Value of the Firm

In conclusion, an optimal capital structure for a firm exists and we can reject the notion that: (1) capital structures are irrelevant; (2) a firm can increase value by increasing the level of debt in the capital structure. As a practical matter, the evidence available to regulators in evaluating the debt ratio urged by a utility is likely to support a range of results. Regulators should strive to find a ratio as close as possible to the optimal (i.e. lowest cost) level, but should recognize that absolute precision is likely to be illusive. Benchmarking the proposed debt ratio against what is in place in other (non-utility) companies of comparable risk, and against the experience in other countries, is likely to be a useful exercise in this context.

For a case study on the estimation of the cost of capital, see Appendix 1.

7. Pricing Design

For most customers the only information they receive about a commodity is transmitted to them in the price signal they receive when they purchase the commodity. Therefore, the pricing function is critical in order to provide the customer with the proper information regarding the cost of that commodity to society and encourage an efficient allocation of societal resources.

General Pricing Principles

A strong argument was made earlier in this paper for setting prices equal to marginal costs. However, for a product such as electric power the actual design of the tariff is generally complicated for the following reasons:

1) Electric power cannot be economically stored. Therefore, product at any moment must equal demand. The lack of economic storage makes the price of electricity very volatile;
2) Electric power is actually composed of several components. The classic definition of electric power separates the product into generation, transmission and distribution. However, even within these functional definitions further delineation can occur; and
3) Different electric customers use different portions of the electric power system. For example, a household customer would use the 0.4 KV distribution system whereas an aluminum smelter would not.

It is therefore necessary to perform detailed studies which estimate the marginal cost of various components of the electric power grid

Adequacy of Data

Most tariff analysts feel that they do not have enough data. No matter what amount of data is available it is human nature to expand the frontier of what is offered by the utility as additional data becomes available which often triggers new ideas.

A special problem exists for developing economies. The books and records of the utility are often in “disrepair” and macroeconomic events such as inflations and currency changes make the existing books and records of the company at best suspect.

No easy single answer exists for this issue. Judgment must be exercised in order to achieve the best outcome given inadequate data.

The attributes of a tariff were best summarized by Bonbright.[6] Bonbright’s Criteria for a sound rate structure are:

1) Effectiveness in yielding total revenue requirements without any undesirable expansion of the rate base (i.e. Averch-Johnson Behavior) or socially undesirable level of product quality;
2) The tariffs would produce revenue that is stable and predictable;
3) The tariffs would be stable and predictable and maintain historical continuity;

[6] Bonbright, James c., Albert L. Danielsen and Davis R. Kamerschen Principles of Public Utility Rates pages 383-4.

4) The price signals sent to customers should discourage inefficient consumption of the utility service;
5) All costs – private and social – should be reflected in the prices of the tariffs;
6) The tariffs should apportion costs fairly between customers;
7) Tariffs should avoid undue discrimination between customer classes;
8) Tariffs should promote dynamic efficiency and innovation to changing supply and demand factors;
9) The tariffs should be simple, certain, understandable publicly acceptable and easy to administer; and
10) Finally, tariffs should be easy to interpret and unambiguous.

Bonbright's criteria suggest that a balance be established between the utility and the customer. The utility receives the financial return it requires to attract new capital, avoid undue volatility be provided with the ability to earn a reasonable return predicated upon reasonable performance. In exchange the customer should receive their service in a safe and reliable manner with a level of performance form the utility that is desired by the community.

Special Issues in Pricing Design

Provision for Vulnerable Customers

Under certain circumstances it is desirable to provide economically disadvantaged customers with a special tariff. The arguments for providing the special tariffs are generally not cost of service based. However, other non-economic arguments may exist which would include the following:

1) Economically disadvantaged customers have a reduced ability to pay utility bills;
2) Low income customers may have the ability to pay a lower cost tariff, but if facing a tariff at full cost of service may opt to simply stop paying any amount for utility service and increase commercial losses; and
3) Charging economically disadvantaged customers a full tariff rate could trigger adverse political and social repercussions.

The challenge of designing tariffs that offer a subsidy to vulnerable customers is that the regulator must be careful not to create an incentive for the vulnerable customer to over-consume the utility's output. A simple discount to the entire rate structure may have that effect. Potential solutions to this problem include the following:

1) Offer vulnerable customers an inverted block tariff design where the discount is applied to the usage charge of the fixed initial block. Usage in excess of the first block is priced at the normal tariff rate. The inverted block tariff design achieves the goal of providing a discount to the vulnerable customer but discourages wasteful usage at least in excess of the first (i.e. discounted usage block). Unfortunately, this approach also provides a discount to people who don't need it.

2) The discount can be applied to the customer charge if one exists. Discounting or eliminating the customer charge provides the vulnerable customer a discount while simultaneously not providing an incentive for wasteful consumption.

A common problem that exists in the vulnerable customer issue is identifying who is a vulnerable customer and who is not a vulnerable customer. The utility is typically not well-equipped to address this issue but often by default is forced to answer this question. To the extent regulators are asked to define the “vulnerable” population, it may be useful to rely on the customer’s eligibility for other social support programs.

Urban versus Rural Tariff Differentials

In many cases cost justification exists to differentiate the tariffs between urban and rural customers. These tariff differentials are driven by the following factors:

1) The differences in customer density between the two areas. For example, a rural area may require significant extensions in the distribution system to interconnect a very small number of customers;
2) The differences in construction technologies. Urban customers are more likely to be served by infrastructure that is more expensive to construct and maintain (e.g. underground distribution systems versus overhead distribution systems); and
3) Relative income level differentials between one group versus the other mat contribute to a higher level of commercial losses.

If it has been established that a tariff differential should exist between the two regions the regulator must face the policy choice of approving or rejecting two sets of tariffs for the separate customer groups. Non-economic tariff criteria that should be considered include the following:

1) Is the price differential permanent or transitory? In some cases the price differential between two geographic regions may not be permanent. If the price differential cannot be reasonably expected to continue into the long-term future establishing a policy of differentiating tariffs by geography is not advisable; and
2) Would an Increased Tariff for a Specific Geographic Group Impact Low Income Customers Adversely? If a cost justification exists for rural customers to pay a more expensive tariff and rural areas are populated by lower income customers such a policy may magnify the problems associated with vulnerable customers.

Inverted and Declining Block Tariff Designs

Inverted and declining block rate designs are applied when a significant differential exists between the average cost and marginal cost to provide service to a customer. The use of inverted/declining block tariff designs allows the customer to receive a marginal cost based price signal while simultaneously allowing the utility to receive the average cost (i.e. the revenue requirement).

Two situations commonly occur which justify an inverted/declining block tariff:

1) Earlier in this paper the topic of natural monopoly was discussed. A regulated natural monopoly will charge a price equal to average cost, which is above the marginal cost. In this case a declining block tariff is justified;
2) If a utility has not made significant capital investments in an extended time period and is facing making these investments in the future a situation could occur where average cost is less than marginal cost. In this situation an inverted block rate design is justified.

8. Revenue Allocation

"… blimey, this redistribution of wealth is trickier than I thought."

Monty Python[7]

To a great extent the allocation of the revenue requirement above or below the marginal cost of a utility is a redistribution of wealth. Like he assessment of a tax by a government the goal of recovering these costs should be focused upon an approach that meets societal goals and introduces the least distortion into the price signal.

Once the revenue requirement for the utility as a whole has been determined the next step in the rate case process is to determine the proper allocation of these costs to specific customers or customer classes. This process tends to be very contentious because every customer or customer class has an incentive to shift costs to another customer or customer class.

A paradox of regulation is that although the aim of regulation is to emulate competitive markets, which establish prices at marginal cost, regulation provides the utility with the opportunity to receive the average cost – the revenue requirement. Various approaches to setting tariffs mitigate the pricing issue at the margin. However, in most cases the revenues received by the utility setting prices equal to marginal costs will not equal the revenue requirement. Therefore, some approach to allocate the difference, positive or negative, must be approved by the regulator.

Cost Allocations, Competitive Threats and Economic Bypass

The threat of non-economic bypass must be considered whenever cost allocations increase prices over marginal costs. Non-economic bypass is defined as when a customer ceases to use commodity because an alternative to using the utility product exists even through the price of the alternative to the customers exceeds the marginal cost for the utility to provide that service.

Consider the following example. A commercial office building has installed electric spaceheating. The marginal cost of the utility to provide that service to the customer is 3¢/KWH and the price paid by the customer is 6¢/KWH. Furthermore, assume that the customer uses 100,000 KWH per year. The estimated profitability derived form this customer is detailed in Table 1 below:

[7] Monty Python, "The Ballad of Dennis Moore."

Item	Amount
Annual Customer Usage per Year (KWH)	100,000
Tariff Price of Electric Power – Cents/KWH	0.06
Marginal Cost – Cents/KWH	0.03
Total Revenue	6,000
Total Marginal Cost	3,000
Total Profitability to Utility	3,000

Table 1 - Calculation of the Profitability of Spaceheating

A seller of small generating units approaches the customer and offers to install a small internal combustion generating unit with a life-cycle cost of 4.5¢/KWH. The customer ceases to use the electric service form the local utility except during periods of outage after the backup generation is installed. The savings captured by the customer for bypassing the utility are detailed below in Table 2:

Item	Amount
Annual Customer Usage per Year (KWH)	100,000
Lifecycle Cost of IC Generation	0.045
Total Customer Cost of Selfgeneration	4,500
Tariff Cost of Electric Power	6,000
Customer Savings	1,500

Table 2 - Savings Experienced by the Customer from Bypass of the Utility

The net economic effect of this investment provides the customer with a savings of 1,500. The electric utility experiences a decrease of 3,000 in revenues for all usage that would have been sold to that customer and a decrease in profitability of 1,500. The decrease in profitability will eventually be captured by the other customers of the utility because they will be paying the remainder of the revenue requirement.

Assign Costs Directly if Possible

In some cases specific cost items can be directly assigned to certain customers or customer classes. For example, if a utility provides a special tariff for providing service to street lighting for a governmental customer the costs to maintain the lighting fixtures for these customers would be directly assigned to that class of service.

The ability to directly assign costs is to a specific tariff class is directly related to the quality of accounting operational data available to the analyst. In general, the higher quality and the more detailed the data used to produce the cost of service study the more likely the regulator will be able to make accurate direct assignment of costs.

Methods to Allocate Costs

In all but the rarest of cases the revenue average price (average requirement) of the utility will not equal marginal costs. Therefore, the regulator will be required to approve some approach to apportion the difference in between the utility revenue requirement and the marginal costs of the utility. Provided below are commonly used approaches to allocating these costs.

Equal Percentage of Marginal Costs

The Equal Percentage of Marginal Cost (EPMC) approach allocates the revenue requirement of the utility to each tariff class by the ratio of the Marginal Cost Revenue Study (MCRS) to the revenue requirement. If the MCRS exceeds the revenue requirement the resulting allocation will provide each tariff class with an assigned revenue requirement that will under-collect marginal costs. In this case tariff designs such as an inverted block (i.e. the tail-block has a higher price than the initial block) is advisable in order to avoid over-incenting customers to consume the utility service.

Table 3 below illustrates the EPMC approach:

	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Total Utility
Results of Marginal Cost Revenue Study	3,000,000	4,500,000	2,250,000	2,250,000	12,000,000
Total Utility Revenue Requirement					20,000,000
Allocation Percentages Based Upon the Results of the Marginal Cost Revenue Study	25%	38%	19%	19%	100%
Revenues Under Existing Tariffs	4,000,000	7,000,000	3,750,000	4,000,000	18,750,000
Revenue Requirement Allocation Based Upon Equal Percentage of Marginal Costs	5,000,000	7,500,000	3,750,000	3,750,000	20,000,000
Revenue Increase Supported by Equal Percentage of Marginal Cost Approach	1,000,000	500,000	-	(250,000)	1,250,000
Percentage Revenue Increase Supported by Equal Percentage of Marginal Cost Approach	25.0%	7.1%	0.0%	-6.3%	6.7%

Table 3 - Example of Equal Percentage of Marginal Cost Approach

A significant disadvantage of the EPMC approach is that it does not address a specific tariff class's price elasticity compared to the other tariff classes and thus may allow non-economic bypass.

Inverse Elasticity

The Inverse Elasticity approach to allocating the revenue requires adjusting the allocation of revenues to each tariff class based upon the relative price elasticity of each tariff class. This approach is superior to the EPMC approach because it explicitly accounts for price elasticity and is less likely to trigger a non-economic bypass of the utility.

	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Total Utility
Results of Marginal Cost Revenue Study	3,000,000	4,500,000	2,250,000	2,250,000	12,000,000
Total Utility Revenue Requirement					20,000,000
Allocation Percentages Based Upon the Results of the Marginal Cost Revenue Study	25%	38%	19%	19%	100%
Revenues Under Existing Tariffs	4,000,000	7,000,000	3,750,000	4,000,000	18,750,000
Energy Charge - $KWH	0.020	0.0300	0.0400	0.0500	
Energy Charge - KWH	150,000,000	210,000,000	46,875,000	12,000,000	418,875,000
Energy Charges	3,000,000	6,300,000	1,875,000	600,000	11,775,000
Customer Charge - $/Customer	10	20	30	40	
Customer Charge – Customers	100,000	35,000	62,5000	85,000	282,500
Customer Charges	1,000,000	700,000	1,875,000	3,400,000	6,975,000
Marginal Energy Cost - $/KWH	0.0210	0.0315	0.0420	0.0525	
Proposed Energy Charge - $/KWH	0.0210	0.0315	0.0420	0.0525	
Proposed Energy Charge Revenues	3,150,000	6,615,000	1,968,750	630,000	12,363,750
Proposed Customer Charge Revenues	4,266,667	7,466,667	4,000,000	4,266,667	7,636,250
Revenue Requirement Allocation Based Upon Equal Percentage of Marginal Costs	5,000,000	7,500,000	3,750,000	3,750,000	20,000,000
Revenue Increase Supported by Equal Percentage of Marginal Cost Approach	1,000,000	500,000	-	(250,000)	1,250,000
Percentage Revenue Increase Supported by Equal Percentage of Marginal Cost Approach	25.0%	7.1%	0.0%	-6.3%	6.7%

Table 4 - Example of the Inverse Elasticity Approach

The above example provides a simplified example of the application of the inverse elasticity rule. In this example the utility has a tariff structure composed of a customer and an energy charge. At the onset we will assume that the energy charge is more elastic than the customer. Furthermore, in all cases the energy charge is not recovering marginal energy costs. The application of the Inverse Elasticity Approach provides for: (1) The energy charge for all classes of service is set equal to marginal energy costs; and (2) Any residual tariff increases are recovered in the customer charge.

A shortcoming of the Inverse Elasticity approach is the availability of accurate price elasticity data. The price elasticity data for a specific utility is often not available. Furthermore, when the data is available it is often subject to controversy given the highly sophisticated analysis required to estimate the price elasticizes. Finally, because household customers may be the “least elastic” group, the use of this method may be politically unpopular because it places a higher proportion of costs on household customers.

Fully Allocated Cost

Fully Allocated Costs (FAC) use the average cost of utility service to allocate costs to each tariff class. This approach is appealing in that the allocated costs will be definition equal the revenue requirement. However, the theoretical economic support allocating costs in this manner is weak.

A recommended application of Fully Allocated Costs is when a functional separation of the utility operations is required. A functional separation would capture the proportional overheads as well as the direct costs for that function. An example of a functional separation would be a utility separating out the costs of an unregulated function.

9. Demand Forecasting and Load Research in the Electric Power Sector[8]

The forecasting of demand, and load research, often play a critical role in establishing price under regulation. It is not enough to understand what the costs and load were in a prior period; in order to set rates that will produce the proper level of revenues in the future, it is essential to estimate the demand, by product and customer class, for all of the utility's offerings. Moreover, because electricity has a different cost at different periods (summer v. winter, different times of day), it is important to study not only the total demand, but also the "shape" of the demand for each pricing element.

Class Demand Studies

Load Research (also known as "Class Demand Studies") are used in order to provide the cost analyst with estimates of demands for various tariff classes. Since the behavior of different varies Load Research data is a critical step in producing an accurate cost study to support the tariff design.

Design of a Load Research Study

Initially the data that is required to perform a cost of service must be specified. A list of information that is generally used in a Load Research programs to support electric cost of service analysis is provided below:

1) Coincident Peak Demand;
2) Class Noncoincident Demand;
3) Coincident Factor;
4) Diversity Factor;
5) On- and Off-peak usage; and
6) Load Factor.

Data Collection

Data collection is generally accomplished through the installation a number of meters with the ability to record data on an interval basis. The data is collected for a minimum of 1 year in order to capture any seasonal impacts on various tariff groups demand patterns.

It is also helpful if demographic data can be collected for the customers who are participating in the Load Research program. This demographic data may include the following:

1) How many people reside at a residence (if it is a household);
2) What appliances are used by the customer and what fuel is used to operate these appliances; and
3) If the customer is not a household, what business is operated at the customer site and what are the hours of operation.

[8] This chapter relied heavily upon the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual, Appendix A.

Estimation of Loads by Tariff Classification
After the sample adapt has been collected analysis is performed to provide estimates for tariff classes as a whole.

Use of Data
Applications of Load Research data for electric cost of service studies would include the following:

1) Determination of coincident peak loads at the generation voltage level in order to determine cost causality for generation costs;
2) Determination of the non-coincident peak loads at various distribution voltage levels in order to determine cost causality for distribution costs; and
3) Estimate the value of energy efficiency and DSM programs.

Load Forecasting

Load Forecasts are a challenge to the regulator. Inasmuch as they are critical to determining the revenue requirement of the utility they are also complex and require specialized knowledge to interpret and evaluate. Many examples exist where the load forecast was ignored in a proceeding resulting in an unexpected outcome for the utility.

The demand forecast a utility provides in a rate case can significantly alter the outcome of the proceeding. Inaccurate load forecasts (i.e. forecasts that overstate or understate sales) will impact the earnings of the utility. If the tariff prices of the utility are greater than the marginal cost to provide that service to customers the utility has a vested interest to understate sales because understated sales will understate the net income of the utility and thus generate a greater rate increase for the utility. Conversely, a customer group has the opposite motivation. Customers have a vested interest in overstating future sales because overstated sales will reduce the tariff prices they pay.

The following example illustrates how an inaccurate load forecast can influence the outcome of a regulatory proceeding. Assume the following:

1) A utility has a realistic forecast of 1,000,000 MWH in sales but in their request proposes that 900,000 MWH of sales;
2) The tariff price is 70 euros/MWH;
3) Operate Expenses are fixed at 50,000,000 euros;
4) The Regulatory Asset Base is 200,000,000; and
5) The authorized overall return is 8.00%.

Item	Accurate Sales Forecast	Sales Forecast as Filed by Utility
Sales of the Utility - MWH	1,000,000	900,000
Existing Tariff Price - Euros / MWH	70.00	70.00
Total Revenues at Existing Tariff Rates	70,000,000	63,000,000
Operating Expenses	50,000,000	50,000,000
Net Income	20,000,000	13,000,000
Regulatory Asset Base	200,000,000	200,000,000
Overall Rate of Return	10.00%	6.50%
Authorized Rate of Return	8.00%	8.00%
Difference - Actual vs. Authorized Return	2.00%	-1.50%
Increase / (Decrease) in Revenues	(4,000,000)	3,000,000
Total Revenues at Proposed Rates	66,000,000	66,000,000

Table 5 - Example of the Impacts of an Understatement in a Load Forecast to a Utility Rate Case

Table 5 provides a simple illustration of the impact of an inaccurate sales forecast. If the regulator was to accept the utility sponsored forecast understating sales the utility would receive in increase of 3,000,000 euros as opposed to a decrease in revenues of 4,000,000 euros.

Load Forecasting Models

A large number of models are available to provide forecasts of utility loads and sales. Two common approaches are briefly discussed below.

Econometric Models of Customer Usage and the Number of Customers – This forecasting approach develops for each tariff class separate forecasts of the number of customers and the average annual KWH usage per customer for a specific tariff classification. The product of the two resulting forecasts for a specific year is the forecast KWH usage for that tariff classification.

End-Use Models – An end-use model develops a forecast of energy usage through a detailed accounting of the number of end-uses by type in the service area. For example, a utility may have 100,000 customers with electric ovens. Engineering estimates are used to estimate the actual usage for each end-use.

For a case study on load forecasting, see Appendix 2

10. Elements of Price/Revenue Cap Regulation

Previous sections have discussed traditional Rate of Return regulation. This section reviews Alternative Regulation Schemes (Alt-Reg).

Goal of Price/Revenue Cap Regulation

Price or Revenue Cap regulation is sometimes referred to as Alternative-Regulation ("Alt-Reg") because it severs the direct tie between the revenue requirement and the utility tariffs. Instead of closely following the revenue requirement, Alt-Reg pegs the utility revenue to a base year revenue requirement and escalated that price based upon an inflation index less an adjustment for productivity.

The purported advantage of Alt-Reg is that it provides the utility with an incentive to maintain productivity equal to peer firms. A utility that is more productive than peer firms is able to attain higher earnings than a firm under traditional regulation. Conversely, an inefficient firm is unable to earn the ROE they would have been granted under regulation.

Price Cap versus Rate Cap

Price Cap and Rate Cap approaches are both intended to provide incentives for efficiency but differ in important respects.

Price Cap Regulation – Under price cap regulation the utility's prices are adjusted according to formula pegged to the rate of inflation less an estimate of the expected change in productivity. It uses the basic formula of "RPI-X," where "X" is the estimated change in productivity for each year of the price cap, and the formula is applied directly to prices.

Revenue Cap Regulation – Under revenue cap regulation, the utility's total revenues are adjusted according to the RPI-X formula; prices will change based on a combination of the allowed revenues and changes in demand.

Thus, the Revenue Cap approach adjusts the allowed revenues based upon the RPI-X approach. Any change in sales levels are implicitly captured in the adjustment. Conversely, the Price Cap approach adjusts prices but the total revenue change will also be influenced by the change in sales.

Implementing an Alt-Reg Mechanism

Alt-Reg is typically implemented as a multi-year mechanism (e.g. 3-5 years). The base line is the first year of the mechanism and proceeding years are adjusted based upon the RPI-X mechanism.

Base Line – index start (often based on Cost of Service case)
In general the implementation of Alt-Reg requires a starting point that provides the basis for the initial revenue requirement. Given that the escalation is applied to a level of revenue or the existing tariff prices it is important that the revenue requirement produced in the base year be somewhat close to what is required to operate the utility in a safe and reliable manner.

It is often difficult, especially when the utility industry is in transition, to establish the base line at a realistic level. If the base line reflects an industry standard that is very inefficient, such as occurred in the UK when their initial privatization occurred, the utility will experience windfall profits. Conversely, if the base line reflects a significant under-recovery of a traditional revenue requirement, the RPI-X mechanism will perpetuate the financial distress of the utility because the available level of productivity improvement will not provide the opportunity for the utility to earn a fair return.

Time Periods after the First Year

After the first year of the Alt-Reg mechanism has been established the prices or revenues are adjusted upward by the RPI-X mechanism.

A description of the underlying structure and logic of the use of an RPI-X approach to regulation is given in the following excerpt from testimony presented in a recent regulatory case in the United States:

> The logic of economic indexes yields results that are useful in designing rate adjustment indexes. One important principle is that if an industry earns, in the long run, a competitive rate of return the trend in the prices that it charges equals the trend in its unit costs. It is then sensible to calibrate a PCI [Price Change Index] for a power distributor by adjusting the X factor to track the unit cost trend of the power distribution industry. The unit cost of a firm can be calculated by taking the difference between the trends in its input prices and total factor productivity ("TFP"). A "stretch factor" may be added to X to facilitate the sharing, between the utility and its customers, of any benefits of stronger performance incentives that are expected under the ARP.
> …
> It is customary to break the PCI calibration exercise down into two terms. One is the productivity differential: i.e. the difference between the TFP trends of the industry and the economy. The other is the input price differential, the difference between the input price trends of the economy and the industry.[9]

Determination of the "X-Factor"

Two approaches exist for estimation of the X-Factor. These approaches are:

Data Envelope Analysis – An approach that uses linear programming an empirical production technology frontier.

Modified Ordinary Least Squares – An econometric approach to estimating the X-Factor.

This topic is extensive and technical and cannot be reasonably addressed in a short section of this paper. We suggest the following reference Efficiency Factor's Determination (X-Factor) submitted by KEMA to the ERRA.

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[9] Testimony of Mark N. Lowry in Maine Public Utilities Commission Docket No. 2007-215, May 1, 2007, at pp. 3-4.

Service Quality and Alt-Reg

An important issue with any type of regulation involving caps is to ensure that service quality does not deteriorate under the cap mechanism. The ultimate goal is to reward the utility for increasing productivity, not reducing service quality.

A common solution to this problem is to establish quality of service standards in the Alt-Reg mechanism. The utility is economically rewarded / penalized for outcomes outside of quality of service bandwidths. Examples of areas for establishing bandwidths are provided below:

1) System average interruption frequency index (SAIFI);
2) Customer average interruption duration index (CAIDI);
3) Power Quality: adequate voltage levels;
4) Customer care/billing;
5) Losses (technical and commercial): index improvements;
6) Average wait time for a customer service inquiry to be answered but a utility representative;
7) A maximum number of consumer complaints to the regulatory authority; and
8) A bandwidth for safety issues with the utility (e.g. the number of lost time accidents).[10]

Penalties and Incentives

After service quality standards have been established the penalty and incentive mechanisms for the various performance measures need to be established. The purpose of the penalties and incentives is generally not to reward increased/decreased productivity but to maintain a standard of service to the customers, though where there is a particular need for improvement over existing service levels, positive incentives can be incorporated into the mechanisms. As an example of the latter, a utility might be eligible for an incentive award if it achieves exceptional performance in reducing technical or non-technical losses.

In general the intention when establishing specific penalties and incentives is to equate the costs to decreased/increased cost to the customers for the change in performance. However, this is often difficult to quantify and therefore very subjective.

Auditing and Verification

The regulator must be able to verify that the performance of the utility meets the standards of the Alt-Reg mechanism in order to quantify the penalties or bonuses. It is therefore necessary that the Alt-Reg mechanism include an auditable reporting mechanism for key utility performance indicators.

For a case study on alternative regulatory mechanisms, see Appendix 3

[10] For a detailed discussion of service quality measures, see “Service Quality Regulation in Electricity Distribution and Retail (Power Systems),” E. Fumagalli, et al (2007).

11. Demand Side Management Using Pricing Techniques

Justification for Demand Side Management

The intuitive response from a layman when they hear about a utility Demand Side Management (DSM) program is "why would you pay someone to not use your product? The answer to this question is straight-forward. A regulated utility has an obligation to serve all customers and it generally not possible to dynamically price utility service (i.e. charge the price of the commodity at that specific point in time). Therefore, it is economically rationale to provide an incentive for a customer to not use the product during certain time periods where the tariff price is exceeded by the marginal cost to serve the customer.

Another description of DSM is to view the utility tariff as a property right of the customer. The customer has a legal right to consume as much of the commodity whenever they desire regardless of the cost to the utility. The utility may only adjust the price of the commodity with the permission of the regulator – generally a process that cannot occur instantaneously. The utility faces the dilemma of providing an incentive to a customer to not use the commodity during high cost periods or incur a reduced return.

Finally, providing DSM to customers may address the problem of negative social costs associated with the production of the commodity. If a negative social cost (i.e. externality) exists the utility tariff will not reflect the full cost to society of the product. Those members of society who are burdened by the existence of the externality are bearing part of the cost of utility production. The DSM program is intended to address this issue by reducing consumption and therefore reducing the external costs transferred to third parties.

Revenue Recovery

Once a DSM program is established a question that often arises is how does the utility recover the revenues from lost sales? The answer to this question often involves delving into the justification behind the creation of the DSM program.

Programs Which Have Established a Threshold of Reducing Revenue Requirements

The first example is a DSM program which has been established to make investments or implement programs that will reduce the revenue requirement of the utility. Although it may seem intuitive that such a program would increase the profitability of the utility and not reduce profitability it also must be understood that many of these programs extend for several years. Impacts in the early years of a specific program may be offset in later years.

Programs that are designed to attack the problem of an externality will often increase the revenue requirement of the utility. The increased revenue requirement occurs because the utility is not paying to abate a private cost that was previously not absorbed by the customer base.

If a program is reducing sales revenues by a greater value than it is reducing costs for the utility it is reasonable and proper that the utility be allowed to adjust the revenue requirements and tariffs to recover these costs.

One issue often faced by regulators with respect to tariff adjustments designed to address utility revenues lost due to DSM programs is how to separate revenues lost due to DSM from revenues lost due to other causes, such as economic recession or increased technical or non-technical losses.

12. Game Theory as a Tool for Regulators

Game Theory is a conceptual and mathematical tool that provides a framework for analyzing what choices rational individuals will make, when the outcome ("payoff") depends on both their choice and the choices of other "players." The application of Game Theory in regulation is in the very early stages, and the analytical tools are very complex. Readers who are interested in this topic should consult the following references.

Roth, A. (1999), *Game Theory as a Tool for Market Design* (1999).

See, also, website maintained by A. Roth at http://kuznets.fas.harvard.edu/~aroth/alroth.html

R. Axelrod (1997), **The Complexity of Cooperation: Agent-Based Models of Conflict and Cooperation**, Princeton University Press, Princeton, NJ.

Ken Binmore and Nir Vulkan (1997), **"Applying Game Theory to Automated Negotiation,"** DIMACS Workshop on Economics, Game Theory, and the Internet, Rutgers University, New Brunswick, April.

Russell W. Cooper (1999), **Coordination Games: Complementarities and Macroeconomics,** Cambridge University Press, Cambridge, UK.

Robert Gibbons (1997), **"An Introduction to Applicable Game Theory,"** *Journal of Economic Perspectives*, Vol. 11, pp. 127-149.

Herbert Gintis (2000), **Game Theory Evolving: A Problem-Centered Introduction to Modeling Strategic Interaction**, Princeton University Press, Princeton, NJ.

David Kreps (1990), **Game Theory and Economic modeling**, Clarendon Press, Oxford, ISBN: 0-19-828381-4 (paperback).

Appendix 1

Case Study: The Approach to Calculating Cost of Capital in the Albanian Regulatory Statement

Background:

The government of Albania is seeking to privatize the electricity distribution elements of its electricity company (KESH). In the context of that effort, prospective investors indicated that it would help their assessment of the investment opportunity if they had a statement from the Albanian Regulatory Body (ERE) concerning the returns that would be allowed by the ERE and used for establishing tariff levels for distribution services. In response to this request, the ERE prepared a draft "Regulatory Statement," outlining how ERE would, for the initial period following privatization, apply the various tariff methodologies. Included in the draft Regulatory Statement was the ERE's summary of how it arrived at the return on equity it would allow for the distribution company.

The portion of the draft Regulatory Statement dealing with the allowed return on equity is reproduced below:

<u>Begin Regulatory Statement Excerpt</u>

From Appendix 2 to the July, 2008 ERE Regulatory Statement

Return on Equity

Different models exist for estimating the required return on equity, but given its common usage, we have selected CAPM model. The respective formula used is:

$$r_e = r_f + \beta * (r_m - r_f)$$

where

β	*equity beta – covariance of return on stock market and return on individual share (β = 1 means the stock market and share have the same volatility and therefore non-diversifiable risk)*
r_m	*Return on the stock market as a whole*
$r_m - r_f$	*Equity risk premium*

Risk free rate

Government bonds are usually used as a proxy – as the lowest risk investment possible. A long term provision does not exist for the Albanian treasury bonds.

Table 2 shows the yield for a number of bonds issued by governments with below – investments grade credit ratings.

Table 2[11]

Country	*Redemption Date*	*Rating (Standard & Poors)*	*Nominal Yield*	*Forecast Inflation*	*Real Yield*[a]
US$-denominated					
Ukraine	Jun 2013	BB-	7.12%	2.4%	4.6%
Brazil	Mar 2015	BB	7.38%	2.4%	4.9%
Turkey	Mar 2015	BB-	7.33%	2.4%	4.8%
Peru	May 2016	BB	7.16%	2.4%	4.6%
Philippines	Jan 2019	BB-	7.67%	2.4%	5.1%
Colombia	Feb 2020	BB	7.87%	2.4%	5.3%
Venezuela	Sep 2027	BB-	7.46%	2.4%	4.9%
Ecuador	Aug 2030	CCC+	10.26%	2.4%	7.7%
Argentina	Dec 2033	B	8.95%	2.4%	6.4%
€-denominated					
Brazil	Feb 2010	BB	4.69%	2.0%	2.6%
Turkey	Feb 2017	BB-	5.87%	2.0%	3.8%
Range (all countries)					**2.6-7.7%**
Average (all countries)					**5.0%**
Average (Ukraine and Turkey only)					**4.4%**

Source: *Financial Times (22 May 2006). Only bonds with a credit rating of below investment grade are shown. US and Eurozone inflation are forecast change in CPI for 2007 as reported in the Economist (20 May 2006).*

a *(1 + nominal yield) / (1 + forecast inflation)*

It seems reasonable to expect that Albania would be rated above the average of Ukraine and Turkey, therefore to assume a real risk free rate of 5% - equal to the average of all countries.

Equity risk premium (ERP)

ERP represents the additional risk involved in holding equity (shares), rather than a risk less asset. It is usually proxied by the difference between returns on government bonds and e stock market index.

In the absence of a stock market in Albania, any estimation of the ERP (and other components of CAPM model), needs to be based on international proxies.

Recent regulatory decisions, as illustrated in Table 3, range from 3.5 – 7 % with a mean of 5.2% and median 5.0 %. This suggests that regulators have settled on a lower ERP than historic levels.

[11] Table 1 is in an earlier part of the regulatory statement.

Table 3: International regulatory decisions on ERP (post-2000)

Country	*Regulator*	*Industry*	*Range of ERP Estimates*		*Most Recent Decision*	
			Min	*Max*	*Date*	*ERP*[a]
Australia	ACCC	Electricity TSO	6.0%	6.0%	2005	6.0%
	ESC	Electricity DSO	6.0%	6.0%	2005	6.0%
Belgium	CREG	Gas DSO	3.5%	3.5%	2006	3.5%
Finland	Ficora	Mobile telecoms	4.0%	6.0%	2005	5.0%
	EMA	Gas TSO	5.0%	5.0%	2004[b]	5.0%
		Electricity TSO	5.0%	5.0%	2004[b]	5.0%
Ireland	CER	Electricity Generation	5.25%	5.25%	2005	5.25%
		Electricity TSO / DSO	5.25%	5.25%	2005	5.25%
Netherlands	Dte	Electricity TSO	4.0%	6.0%	2005	5.0%
		Electricity DSO	4.0%	7.0%	2005	5.0%
		Gas DSO	4.0%	6.0%	2005	5.0%
	Opta	Post	6.0%	6.0%	2002	6.0%
New Zealand	Commerce Commission	Gas DSO	7.0%	7.0%	2004	7.0%
		Electricity DSO	7.0%	7.0%	2005	7.0%
UK	Ofgem	Electricity DSO	3.25%	4.8%	2004	4.8%
	Ofwat	Water	3.0%	4.0%	2004	4.5%
	Ofcom	Telecoms – wires	4.5%	4.5%	2005	4.5%
		Telecoms – retail	4.5%	4.5%	2005	4.5%
	Postcomm	Post	4.0%	5.0%	2005	4.5%
	CAA	Airports	3.5%	4.5%	2005	4.0%

Source: PricewaterhouseCoopers (May 2006). *TenneT TSO: Comparison study of the WACC.* Final Report (downloadable from http://www.dte.nl/images/Comparison%20study%20of%20the%20WACC-%20Mei%202006_tcm7-87013.pdf) and ECA research

We use an assumed ERP of 7.0 % in the estimation of WACC, based on historic levels and not on recent regulatory decisions in EU countries.

Beta - β

It is clearly not possible to estimate β –s directly for DSO, therefore we have relied largely on recent regulatory decisions from other countries, as shown in Table 4.

Table 4: International regulatory decisions on equity betas (post-2000)

Country	*Regulator*	*Industry*	*Range of Beta Estimates*		*Most Recent Decision*	
			Min	*Max*	*Date*	*Beta*[a]
Australia	ACCC	Electricity TSO	1.00	1.00	2005	1.00
	ESC	Electricity DSO	1.00	1.00	2005	1.00
Belgium	CREG	Gas DSO	1.00	1.00	2006	1.00
Finland	Ficora	Mobile telecoms	1.40	1.43	2005	1.415
	EMA	Gas TSO	0.35	0.35	2004[b]	0.35
		Electricity TSO	0.44	0.44	2004[b]	0.44
Ireland	CER	Electricity Generation	1.00	1.50	2005	1.22
		Electricity TSO / DSO	0.60	1.00	2005	0.80
Netherlands	Dte	Electricity TSO	0.27	0.58	2005	0.58
		Electricity DSO	0.45	0.85	2005	0.605
		Gas DSO	0.43	0.59	2005	0.51
	Opta	Post	0.76	0.76	2002	0.76
New Zealand	Commerce Commission	Gas DSO	0.60	0.60	2004	0.60
		Electricity DSO	0.58	0.58	2005	0.58
UK	Ofgem	Electricity DSO	1.00	1.00	2004	1.00
	Ofwat	Water	0.70	1.00	2004	1.00
	Ofcom	Telecoms – wires	0.80	0.90	2005	0.85
		Telecoms – retail	1.10	1.20	2005	1.15
	Postcomm	Post	0.81	0.94	2005	0.875
	CAA	Airports	0.80	0.80	2005	0.80

Source: PricewaterhouseCoopers (May 2006), *TenneT TSO: Comparison study of the WACC*, Final Report (downloadable from http://www.dte.nl/images/Comparison%20study%20of%20the%20WACC-%20Final%202006_tcm7-87013.pdf) and ECA research.

From the table, it appears that those businesses operating in more competitive markets are considered to have a higher equity β.
For calculation of return on equity purposes we have assumed a β = 0.80, considering the midpoint of maximum estimated beta.

Estimated after tax return on equity

Considering a profit tax rate of 10 % in Albania, making the tax wedge = 1/(1-0.10) = 1.11.
The return on Equity calculation is

The calculation of the RoE is given below:

Component		
real risk free rate	r_f	5.00%
ERP (equity risk premium)	$r_m - r_f$	7.00%
Equity β	β	0.80
Cost of equity	$r_e = r_f + \beta *(r_m - r_f)$	**10.60%**
Tax Wedge	$1/(1-t_c)$	1.11
pre-tax cost of equity	$r_{e\ pretax} = 1/(1-t_c)*\ r_e$	**11.78%**

End of Regulatory Statement Excerpt

Questions and Comments

On its face, the Regulatory Statement appears to reflect a straightforward application of the CAPM methodology for estimating the return on equity to be allowed. The details of the Statement, however, raise a number of important questions with respect to each element in the calculation.

1. Risk Free Rate

Is there data available concerning the risk free rate in the subject jurisdiction? If not, what proxies can be used? Are those proxies sufficiently representative of the subject jurisdiction?

The ERE's approach to estimating the risk free return for Albania adopted a methodology of examining the returns of government bonds for "peer" economies as shown in Table 2. A risk inherent in the ERE's approach is the complexity added when comparing bond yields in economies using different currencies. The differences in the bond yields can be explained not only by different levels of risk but also market expectations for changes in the exchange rates of the different currencies.[12] This relationship can be observed in the sample of countries used in their analysis. The countries using US dollar denominated currencies have significantly higher yields than economies using Euro denominated currencies. In this case the reason the yields were higher for US dollar denominated currencies is because the dollar was expected to devalue compared to the Euro. This information in the tables used by ER reflect market conditions on 22 May 2006 and an exchange rate between the Euro and US dollar of 1.2582 Euros/US dollar. The current exchange rate is 1.5409 Euros/US dollar. The degradation in the value of the US dollar contributed to the higher yields for the bonds in countries that are denominated to the US dollar versus the Euro.

[12] Economics textbooks refer to this behavior as the Interest Rate Parity Theory.

An alternative approach to estimating the risk free interest rate for Albania that would avoid this concern would be to adopt the yield for debt issued by the Government of Albania and assume that rate is the risk free interest rate for that country. A second approach is to adopt the risk free interest rate from a major European country and add in the country risk premium for Albania. The country risk premium is published by major banks and rating agencies.

The risk free rate can often be observed directly in mature markets. In the United States, for example, U.S. Treasury Bonds are considered to be risk free, and their return can be directly observed. Where comparable securities are available, the question for regulators in applying the CAPM is what maturity to select; because equities have no maturity, regulators generally use relatively long term bonds as the benchmark for the risk free rate. In developing markets, however, it may be difficult to identify a genuinely risk free security, and proxies are necessary. In the draft Albania Regulatory Statement, the ERE has selected a number of debt instruments from nearby jurisdictions as a basis for estimating the risk free rate. Issues that may arise with respect to the selection of these instruments as proxies include: Has the risk free rate been overstated by the use of below-investment grade securities as proxies? On the other hand, has the rate been understated by the inclusion of securities in markets that are more developed than Albania (e.g. Brazil)?

2. Risk Premium

What is the basis for choosing the jurisdictions from which the risk premium will be derived? Are those jurisdictions reasonably comparable to the subject jurisdiction (in this case Albania)? What is the basis for establishing the difference between equity and debt returns? Are the equity returns actual returns or allowed returns? What is the basis for choosing a particular point in the range of data?

In general, care should be taken to ensure that, to the extent possible, the data used to estimate the risk premium is as comparable as possible to the subject jurisdiction, and that market data, rather than regulatory decisions, form the basis for the calculation. The first is important because there may be a substantial difference between the risk premium in a mature market with well established financial markets and stable legal and regulatory structures and the risk premium in developing markets and economies. The second is important because using the decisions of other regulators, while those decisions may provide a useful benchmark in some contexts, may be influenced by many factors unrelated to what investors require. Again, this element is especially important in developing markets and structures, where there may be little history of how investors respond to particular decisions.

The factors used to estimate the risk premium in the draft Albania Regulatory Statement might, therefore, be challenged on the grounds that it uses data from more developed markets in the EU. On the other hand, the Regulatory Statement uses the high point from the data (i.e. 7.0% risk premium) in recognition that the Albania market is less developed and thus is likely to be viewed as having a higher risk. In the absence of data from more closely comparable markets, this approach may be viewed by investors as reasonable.

3. Beta

What is the basis for selecting the sample of jurisdictions for estimating Beta? What is the basis for determining the risk of the subject utility relative to the firms represented in the data?

The selection of Beta in the CAPM formula can have a very significant impact on the allowed equity return. At the same time, it can be very difficult to estimate, because it most often cannot be observed directly – there usually no available history, for example, for the Beta for the subject utilities. It is, therefore, important to use data from companies that are as close, both in their own character and in the maturity of the market in which they operate, to the subject utility.

The draft Albania Regulatory Statement again uses jurisdictions with more mature markets for comparison, raising the issue of whether data from those jurisdictions can fairly be applied to the Albania distribution company. The observation that competitive companies have higher Betas is clearly correct, but that does not provide a direct answer to where the Beta should be set for a newly privatized distribution company in a developing market. Some might argue, for example, that the Beta for such a company could be higher than the market average, because the risks for the new company, even though it is not in a "competitive market," are very significant. In particular, it might be difficult to justify selecting a Beta of 0.80 (below average risk) for the Albania distribution company when the Beta found in the UK for the electricity distribution company was 1.00 (average risk).

Appendix 2

Case Study: Load Forecasts in the context of Price Cap Regulation

Background:

In Maine, in the United States, the major electric distribution company has been subject to price cap regulation since the mid-1990s. At the conclusion of the second price cap plan, which began in 2000 and extended through 2007, the Maine regulatory body (Maine Public Utilities Commission, or "MPUC") examined whether a new price cap plan should be implemented, and if so under what terms.

One of the central issues in the MPUC consideration of the proposed new price cap plan was the likely level of revenues – and thus profitability – of the utility (in this case Central Maine Power, or "CMP") over the course of the proposed plan. In order to estimate the profitability under the proposed rate level, and with the application of the RPI-X formula proposed in the case, the MPUC had to develop a record concerning the expected load during the period that the rates would be in effect. The overall case itself was concluded when the parties reached agreement on the terms of the new price cap plan; while the MPUC never explicitly resolved the issues raised concerning the load forecast, the settlement was based on a forecast that showed higher growth than suggested by CMP's testimony but lower than that suggested by the MPUC staff.

Estimating Load over a Price Cap period

Attached as part of this case study are the "pre-filed written testimony" submitted by the utility (CMP) (Attachment 1) and by the MPUC staff (Attachment 2) concerning the forecast load. As reflected in the testimony, load forecasts are both vital and complex, and require the exercise of judgment as well as the application of econometric tools. A sample of the techniques and issues that arose during the case is presented below:

* The relationship between the forecasts used in the litigation and forecasts used by the utility to plan its business. Forecasts used for business planning may be considered more "reliable" by the regulator, because the utility has an incentive to be as accurate as possible and not distort its forecast for the purpose of obtaining a higher rate.

* Different estimating techniques may be required for the different customer classes. For example, for the largest customers, the utility discussed the likely future level of usage directly with each customer. For household customers, the utility proposed a mix of econometric modeling and trend analysis. In modeling future household usage, many factors are likely to be relevant, including changes in income, changes in the efficiency and use of electric appliances, and response to price changes.

* Forecasts should be adjusted to reflect "normal" weather. Because electricity consumption may be highly variable with temperatures, for example, data from past periods may not present a good basis for estimating future load unless the differences between the weather in the past periods and "normal" weather is taken into account.

* A regulatory body should compare the actual data from past periods with the projections previously made by the utility. In other words, if the utility's estimating methods

consistently underestimate load, it may not be reasonable to rely on the utility's current estimates.

* For classes where future load is estimated based on econometric modeling, it is important to take into account both changes in usage per customer or household, and changes in the number of customers.

* The challenges to the utility's forecast (in these materials reflected in the "Bench Analysis" prepared by the MPUC staff) can be based on benchmarking, for example how does the utility's forecast or the data upon which that forecast is based compare with other utilities, or differences in methodology, for example whether the appropriate "variables" have been incorporated into the forecasting models.

Summary and Conclusions

As the body of the paper observes, load forecasts play a critical role in developing rates. As indicated in the attached materials, forecasts of load can be central in a regulatory body's consideration not only of rates for a single year, but also of the implementation of a price cap plan, because some estimation of revenues may be an important consideration in developing the exact terms of the plan. As the materials reflect, load estimation can be complex and requires a good understanding of what factors are likely to influence future load growth, always recognizing that, as with any prediction about future events, there will inevitably be a significant range of uncertainty, and that uncertainty increases the farther into the future the projections are made.

Another issue that may arise in the context of load forecasting is whether some special provision should be made for changes in load due to specific government policies that could alter the load expected in the forecasts in a material way. For example, new conservation programs might result in reductions in load not contemplated in the load forecasts used to set the rate trajectory in the price cap plan. In such circumstances, it may be appropriate to included, as an annual rate adjustment factor, an allowance for the decline in load (and the resulting decline in revenues) attributable to the new program. Care must be taken, however, to ensure that the impact of the program is isolated from the effects of changes in the general economy or of business cycles, as the risks associated with those changes are placed on the utility as part of the price cap approach.

Appendix 2 - Attachment 1

Davulis basic sales
forecast A...

Appendix 2 - Attachment 2

VARIABLES IN CMP'S RESIDENTIAL SALES EQUATION

Introduction

In this section we describe our analysis of CMP's residential sales forecast. We have evaluated the economic theory underlying CMP's regression equations and whether alternative mathematical specifications of relationships between economic factors and sales – different variable definitions, mathematical transformations and autocorrelation adjustments – are appropriate. We have also analyzed each of the variables that CMP uses in its regression analysis – price levels, aggregate income, air conditioning saturation, and weather. The next section addresses variables that CMP did not include in its regression analysis including historic DSM, space heat usage and the final section presents our final baseline forecast and sensitivity analysis of the forecast.

The discussion of CMP's regression equation is organized by first explaining our process for benchmarking to the CMP forecast of use per customer and the number of customers. Next, we describe our analysis of the factors used in CMP's analysis beginning with the customer growth analysis and then moving to the income variable, the price variable and variables intended to reflect the effect of weather on sales.

Benchmarking to CMP

The first step of our analysis was to use the data provided by CMP and then to replicate their regression equations and their forecasts. This part of the analysis is important both because it confirms that CMP's statistical analysis is valid and because it assures that when we change a variable in the analysis, that our adjustment to the forecast is indeed the result of that change and not the result of a different underlying statistical procedure. We have benchmarked both CMP's residential use per customer equation and the equation for customer growth equation. Matching the CMP equations is made somewhat complicated because of the presence of autocorrelation in the data. This means one cannot simply use the CMP data and plug it into a regression package, but that the method for adjusting the data to correct for autocorrelation must also be factored in.

In constructing our benchmarking analysis we attempted to match CMP's autocorrelation adjustments and its forecasts as well as the coefficients in the regression equations. When using CMP's autocorrelation factor, we were able to closely match both the coefficients ant the t-statistics that the Company presented in its testimony as shown in the table below.

Benchmarking of CMP Residential Equations

	CMP		Replication	
Variable	Coefficient	t-Stat	Coefficient	t-Stat
LogRPOE	(0.27026)	-5.19	(0.27026)	-5.28
LogRYP_YRCUST	0.25586	2.32	0.25586	2.41
HDD	0.00009	9.20	0.00009	9.29
THICDD	0.00015	2.42	0.00015	2.44
LogACTREND	0.06640	1.79	0.06640	2.05
ICESTORM	(0.04620)	-3.13	(0.04620)	-3.15
DUMMY3	0.32478	2.27	0.32479	3.62
_CONST	5.14563	9.69	5.12970	
_AUTO	0.94152	36.47	0.94152	

When we made a forecast with the above parameters, our forecast was virtually identical to CMP's forecast which confirms that our comparisons below are not distorted by different statistical techniques. When we computed the autocorrelation factor from the regression equation residuals rather than entering the value used by CMP, we developed a slightly different factor (.9021 versus .9415.) The small difference in the autocorrelation estimate had a minimal effect on the ultimate regression forecast. In replicating the CMP results, we did confirm that CMP's equation in fact closely fit the historic data.

CMP uses a separate regression analysis to forecast the number of customers and we have attempted to match that equation as well as the use per customer equation. As with the customer use equation, the coefficients and our forecasting results were very close to the results presented by the Company. (In the case of the customer equation, we replicated the CMP autocorrelation factor.) The comparison of regression coefficients is shown on the table below.

Benchark of Customer Equation					
	CMP			Replication	
	Coefficient	t-Statistic		Coefficient	t-Statistic
Gains -1	0.796	21.762		0.796	21.92
Starts	0.172	6.015		0.172	6.07
Const	0.239	1.761		0 239	1.771
Auto - 4	(0.413)	(3.552)		(0.409)	(3.564)

Income Variable in the Residential Use per Customer Forecast

We begin the discussion of how we have investigated alternative variables by describing the income variable in CMP's analysis. In analyzing CMP's approach to modeling income we have done the following:

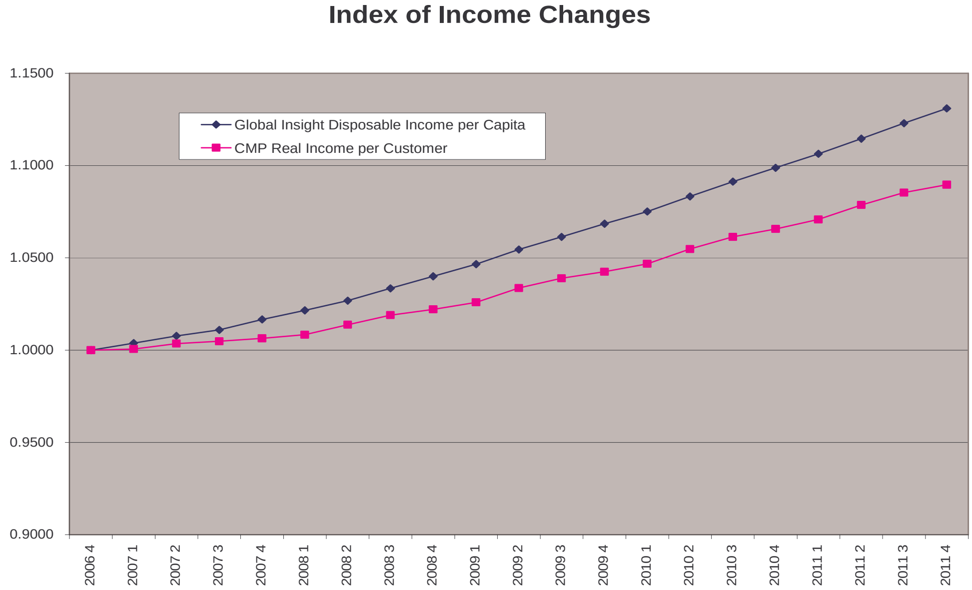
- Reviewed how CMP incorporates income in the forecasting analysis;
- Compared CMP's approach with the method used by some other utility companies;
- Recommended an alternative approach to incorporating income in the regression analysis which directly uses the Global Insight disposable income per capita rather than the manipulated variable that CMP creates.

CMP Approach to Modeling the Effects of Income

CMP gauges the effect of changes in housing size, size of appliances and many other factors on residential sales through including a variable that measures how much income the average customer earns for each period. The ultimate source of the historic income per customer and the projected income per customer data that CMP uses is disposable income in Maine published by Global Insight.[13] Although CMP discusses the Global Insight income projection, the Company in fact does not directly use the Global Insight data for Maine disposable income per capita in its regression analysis. Instead, the Company adjusts the Global Insight data to derive a variable which it names real income per customer. The graph below shows that CMP's income variable ultimately produces a lower forecast of income than the Global Insight per capita income. The graph demonstrates that from the first forecast year of 2007 through the year 2011,

[13] CMP defends the use of Global Insight as a source for measuring income through comparing it to three other forecasts. However, CMP makes the comparison in nominal terms rather than real terms. In real terms, the Global Insight forecast is lower than the forecast of the State Planning Office by .92% in 2007 and 2008.

CMP's income variable grows by somewhat less than 15% if the Global Insight disposable income per capita is used while it grows by about 10% if the CMP adjusted variable is used.



Modeling of Income by Other Utility Companies

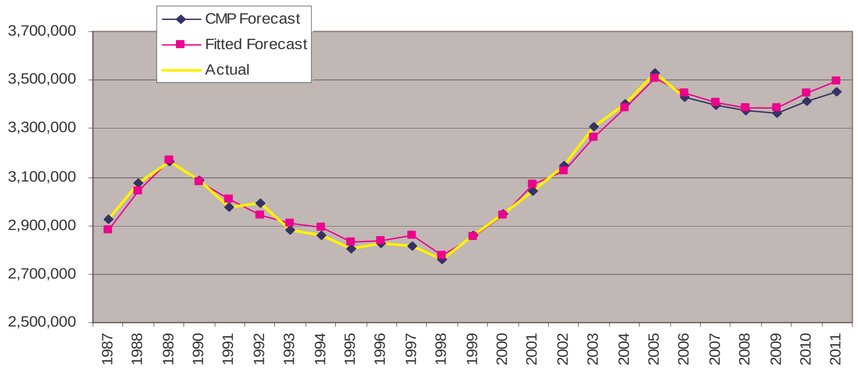
In evaluating whether CMP's approach of adjusting disposable income per capita is appropriate we have reviewed some information with respect to sales forecasting techniques used by other utility companies. In their recent case, Bangor Hydro used real per capita income projected Moodys.com and did not manipulate the data further. CMP's approach is also not consistent with forecasting techniques used by New York electric utilities that are subsidiaries of Energy East. According to a data request response provided by CMP, the New York electric companies use Moodys.com as does Bangor Hydro and the documents did not describe any adjustments to the income variable (the New York gas companies do not use an income variable.)

Recommended Approach to Modeling Income

We recommend directly using the Global Insight income per capita variable rather than the variable manipulated by CMP. It is not logical that the income divided by customers should grow at a significantly different rate than income per customer. Even if a justification could be made for CMP's approach on a prospective basis, the use of income per capita to establish relationships between use per customer and income would account for any historic difference. At best, CMP's approach does not add anything to the quality of the forecast. At worst, manipulation of the income variable biases the forecast.

Directly using the Global Insight income per capital variable produces a higher forecast than an equation which uses CMP's income definition. This is illustrated in the graph below. The graph uses all of the CMP variables and econometric techniques except for the income variable. When the Global Insight income per capita is directly used, the income elasticity increases, the t-statistic on the income variable changes and the R-squared of the regression increases.

Forecast Log Use per Customer
Versus Log Price Lag 4 and Log of Global Insight and others



When the Global Insight variable is substituted for the CMP variable, the forecast of use per customer increases as shown on the right part of the graph above. Relative to the CMP forecast, use of the alternative variable increases the forecast by 0.21%, 0.46%, 0.72%, .95% and 1.21% for the years 2007, 2008, 2009, 2010 and 2011.

Price Variable in Residential Use per Customer Forecast

The manner in which price elasticity is reflected in the residential forecast is an important issue in this case because of the sharp increases in energy prices that occurred in the past couple of years. When lagged prices are used in the regression equation to compute price elasticity, sales forecasts are reduced because the increases in 2006 price effect the forecast in 2007. We address many of the theoretical issues with respect to price elasticity in the appendix. The discussion in this section below focuses on the following practical issues:

- A review of CMP’s approach.
- A discussion of the approach to computing price elasticity used by other utilities and BHE.
- A description of statistical problems with price elasticity measurement that occur because the level of historic sales affects prices.
- A summary of our recommendation with respect to price elasticity.

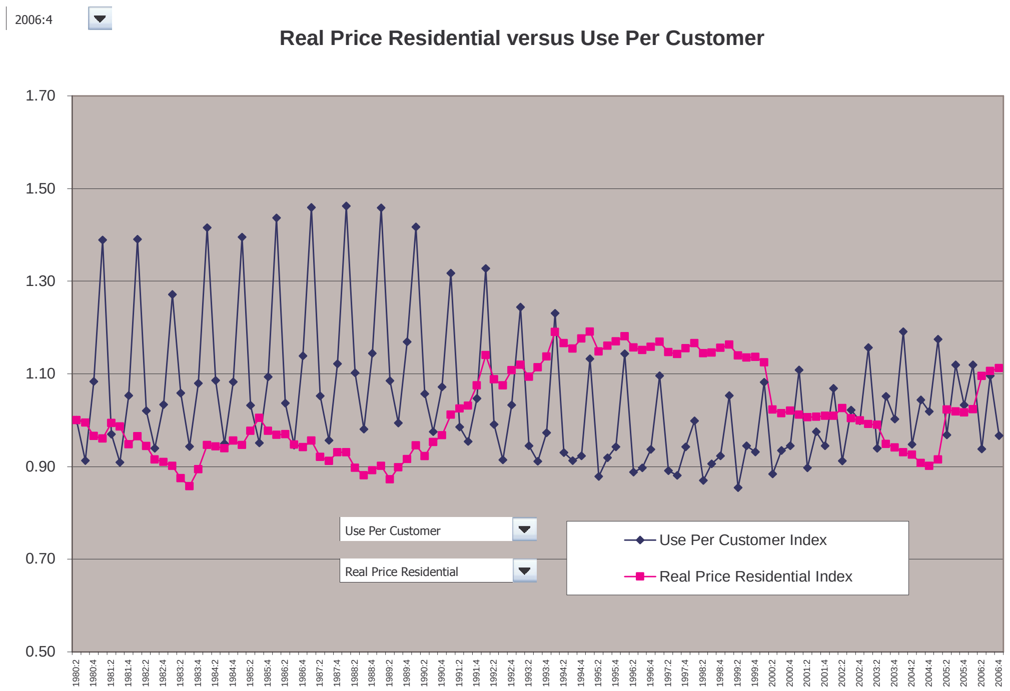
Review of CMP’s Price Elasticity Approach

CMP uses the historic relationship between sales and lagged prices to conclude that the price elasticity is -.27. This means the when the real price increases by 10%, sales will decline by 2.7%. Given that prices increased in 2006 and CMP uses lagged prices in modeling price elasticity, a high price elasticity parameter aggrivates the effect. The high value of the price elasticity parameter combined with the high 2006 prices implies that alternative techniques for modeling price elasticity can have a large effect on the sales forecast. The table below shows that CMP’s price elasticity parameter is higher than its price elasticity parameter in prior cases and is higher than the average price elasticity tabulated in a survey of electricity utility companies.

Alternative Residential Price Elasticity Parameters	
CMP Price Elasticity Estimate	-0.270
CMP Price Elasticty Forecast in 2005 Equation	-0.174
CMP Price Elasticty Forecast in 2004 Equation	-0.269
Average Price Elasticity in Utility Survey	-0.150

The theory underlying price elasticity is that there is some inherent true parameter which measures the manner in which consumers change their consumption when prices change. If this theory is valid and such a true parameter exists, then a robust regression equation would not result in a price elasticity parameter of -.27 this year and a parameter of -.174 last year.

The graph below illustrates why the price elasticity parameter measured by CMP is quite high as prices increased along with the decreased sales in the mid 1990's and then sales increased after the prices declined around the year 2000. The price increases shown on the right hand side of the graph are important for the forecast. By assuming that sales are a function of lagged prices, those 2006 price increases shown at the end of the graph cause sales to decline in 2007.



Although the graph does show that sales generally when down when prices increased and that sales increased with lower prices, the graph does not prove cause and effect. Before deregulation, a decline in sales would cause revenue per kWh to increase to the extent that revenue requirements were fixed. This implies that sales changes could cause price changes rather than price changes causing sales variation. Further it is possible the sales changes happened to occur when prices changed and the effect could be random.

Price Elasticity Techniques Used by Other Utility Companies

CMP's approach to modeling price elasticity by assuming that consumers will wait one year when reacting to prices is not consistent with the manner in which other utilities construct econometric equations for forecasting sales. This is confirmed by the following:

- CMP provided a survey of the techniques used by utility companies in making price forecasts. In this survey, there were a series of questions regarding price elasticity and lags. The questions addressed whether utilities used current prices, prices with a one month lag or the moving average of prices. There was no survey question that addressed the possibility of using only a full year lag and no current price variable.
- In the survey provided by CMP, most of utility companies in the U.S. that responded used either current prices that are not lagged or prices lagged by one month.
- The sales forecast developed by BHE applies average prices in the past four quarters rather than lagged prices.
- In the information CMP provided about other Energy East companies, there was no indication that the companies used a lag of one year in computing price elasticity.

Statistical Issues in Measuring Price Elasticity

A basic assumption when constructing an econometric model is that independent variables such as price change because of changes in the dependent variable (residential energy use). As stated above, in the case of residential energy sales, when sales decline, the revenue requirement formula causes average price increases putting into question the cause and effect that is a basic proposition when developing regression analysis. This problem which is known as simultaneity causes the price elasticity parameter to be biased. We do not suggest eliminating the price variable from the regression equation or developing an alternative statistical approach. However, the statistical problem means that one should be cautious in interpreting the price elasticity parameter.

Residential Price Forecast

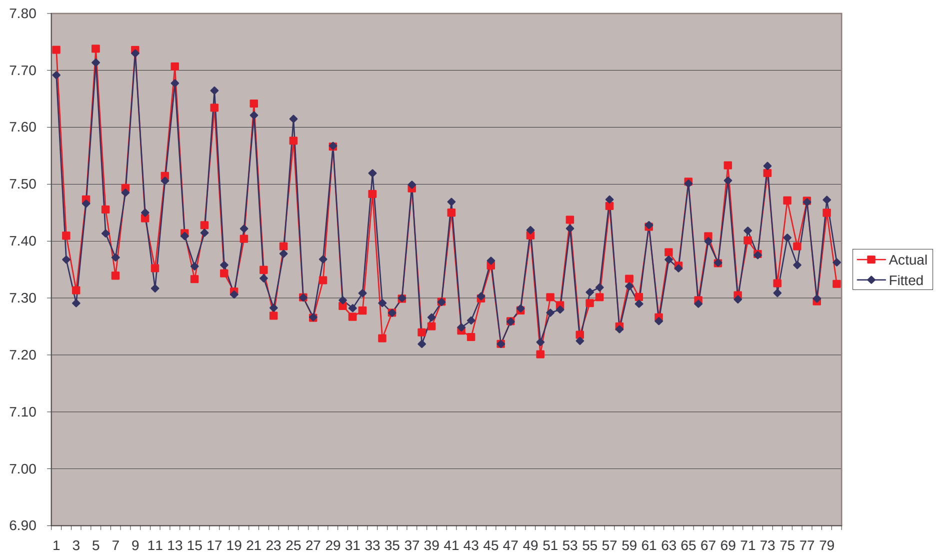
The effect of prices on sales projections depends on assumptions about the future price of electricity as well as the price elasticity parameter. CMP projects the real residential price to decline mainly because stranded investment charges are reduced (from 2007 through 2011 stranded investment charges are projected to decline by 75%.) The decline in stranded investment charges is tempered by an increase in transmission rates which are projected to increase by 25% over the 2007 through 2011 period. Distribution prices are projected not to change from a revision in baseline rates and then to change from inflation assumptions and the .5% proposed productivity offset. Finally, supply charges are projected to increase by 2.7% derived from forward prices published by NYMEX.

We have evaluated CMP's prices and with the exception of distribution prices we find their assumptions reasonable. In the case of distribution prices, we have assumed a 10% reduction in baseline rates and then a 1.75% productivity factor. This reduces overall prices by as much as 4% relative to the CMP projections.

Recommended Approach to Incorporate Price Elasticity in the Sales Forecast

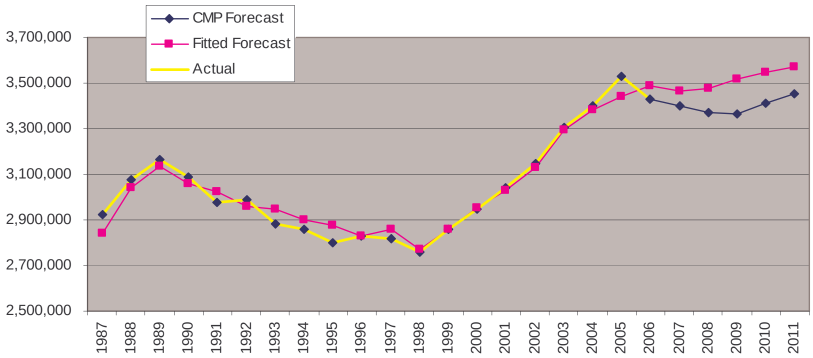
Given the discussion above we recommend that the price elasticity parameter and the sales forecast use current prices rather than lagged prices. When current prices are used rather than lagged prices, the elasticity coefficient declines from the -.27 to -.114. Further, the R-squared of the regression declines and the actual data are somewhat above the fitted data for the year 2005 as shown in the graph below. The fact that a somewhat better fit to historic data occurs through use of a four quarter lag does not justify use of a variable that is not logical. The section below includes a detailed discussion of why CMP's approach of searching for variables that fit historic data is inappropriate even if it results in a slightly higher t-statistic and R-squared.

Fitted and Actual After Four Lag Autocorrelation Adjustment



Keeping all variables except price the same as those proposed by CMP and replacing the lagged price variable with the current price results in sales that increase relative to CMP's forecast by 1.98%, 3.02%, 4.22%, 3.41%, and 2.92% for 2007, 2008, 2009, 2010 and 2011. When the alternative distribution prices as well as the elasticity are incorporated in the analysis, the sales forecast is 1.98%, 3.20%, 4.61%, 3.85% and 3.43% above the CMP forecast for the years 2007 to 2011. The effect of using current prices rather than lagged prices on fitted data and the forecast is shown on the graph below.

Forecast Log Use per Customer
Versus Log Alt Real Price and Log of CMP Income per Customer and others



Weather Variables in Residential Use per Customer Forecast

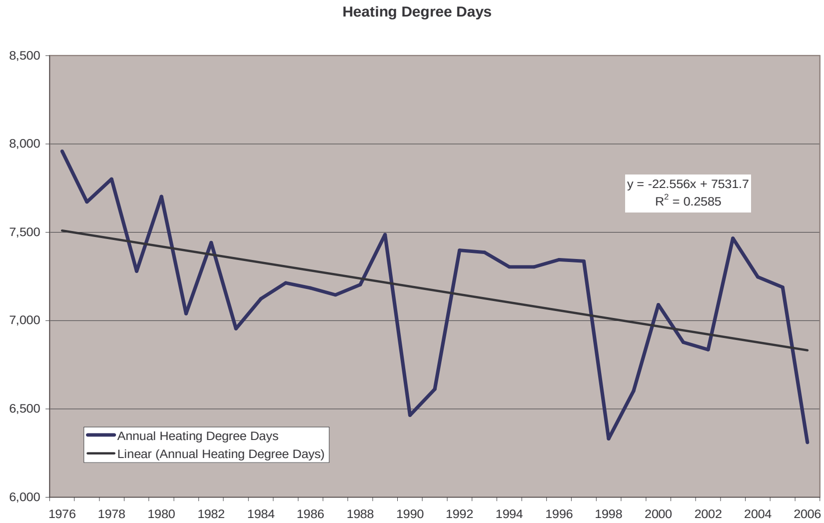
Besides price and income, the principal other factor that CMP uses in its equation are variables to represent weather. CMP includes heating degree day and humidity adjusted cooling degree day variables to represent the weather in its econometric analysis and it assumes that the average conditions in the past fifteen years represent future weather conditions. Other than its adjustment for humidity, CMP's approach to reflecting normal weather in the forecast is consistent with the method used by other companies. Our recommendation with respect to weather variables is to use unadjusted cooling degree days rather than cooling degree days adjusted for humidity. We do not make adjustments to the weather data for different cut-off points or make adjustments for global warming.

The remainder of this section discusses our observations with respect to CMP's weather modeling. Our first observation with respect to CMP's incorporation of weather in its models is that the Company's adjustment to include humidity as well as temperature in the cooling degree day calculations does not fit the historic data as well as the cooling degree days without adjustment. Our second observation is that since heating and cooling degree days are calibrated to 65 degrees Fahrenheit, the variables are not ideal representations of how weather affects sales. Our third observation is that the heating and cooling degree day series exhibits trends that reflect global warming, implying that use of the fifteen year average is not a good representation of normal weather.

CMP makes an adjustment to cooling degree days to incorporate humidity as well as temperature in the variable. The humidity adjusted variable is named THICDD while the unadjusted variable is called CDD. Since humidity affects the way consumers use air conditioners, one would expect adjusted variable THICDD to fit the historic data better than the unadjusted CDD cooling degree day variable. This however is not the case. If the variable without the humidity adjustment is substituted for the CMP adjusted variable, the t-statistic is higher and the sales forecast increases. Specifically, relative to the CMP forecast, use of the CDD variable instead of the THICDD variable increases the projection of residential use by .21% to .47%.

Cooling degree days and heating degree days are computed adding up the differences between each day's average temperature and 65°F. This measure is not necessarily the best measure of how weather affects electricity sales because people most probably do not begin using their air conditioner until the temperature is higher than 65 °F and they do not begin using their space heaters until the temperature is colder than 65 °F. These problems mean that the weather variables contain an "error in variables" problem that makes interpretation of the regression equations problematic. This issue is discussed in more detail later in the Appendix.

In reviewing the weather variables it is apparent that heating degree days have declined implying warmer winters and cooling degree days have increased suggesting warmer summers. The downward trend in heating degree days is illustrated in the graph below. While it would be reasonable to use shorter periods or trends in projecting the heating and cooling degree day variables, the effect of warmer winters offset warmer summers and such adjustments would probably not have much effect on the ultimate forecast. Further, the heating and cooling degree day are not ideal in measuring the effect of weather on sales and incorporating heating degree days would imply a level of accuracy that is not present.



Forecast of Number of Residential Customers

Once the use per customer is developed, the number of customers is multiplied by the use per customer to project total residential sales. We discuss our review of CMP's residential customer forecast in the paragraphs below. Our conclusion is that the overall structure of CMP's econometric equation is reasonable, but that additional time periods should be used and lagged housing starts should be used instead of current housing starts. This recommendation produces a small increase in the number of customers. Our discussion of the number of customer analysis is separated into the following:

- Review of CMP's approach to forecasting customers
- Evaluation of CMP's approach compared to the method used by some other utility companies
- Analysis of alternative specifications for the customer regression equation
- Summary of the alternative recommended equation.

CMP's Approach to Forecasting Customers

CMP has created an equation for the change in customers compared to a year earlier which it names customer gains. CMP projects the number of customers on a quarterly basis which means the gains are computed as the difference between the number of customers for the current quarter and the number of customers four quarters ago. The Company projects the customer gains as a function of the one quarter lagged customer gains and the number of housing starts in the quarter. The variable which dominates the equation is the number of gains in the prior quarter. This approach amounts to assuming that the number of customer gains follows a moving average process by which future gains depend on the number of historic gains with a slight effect of housing starts.

In developing the customer gains equation, CMP uses a different time period from the time period it uses in developing the customer use equation. For customer use, the Company estimates the equation beginning with data in 1986. In contrast, the customer equation is estimated using a time period beginning in 1990. While this may seem to be a minor point, CMP’s method ignores large swings in customer additions that occurred before 1990 and provide valuable information in estimating an equation.

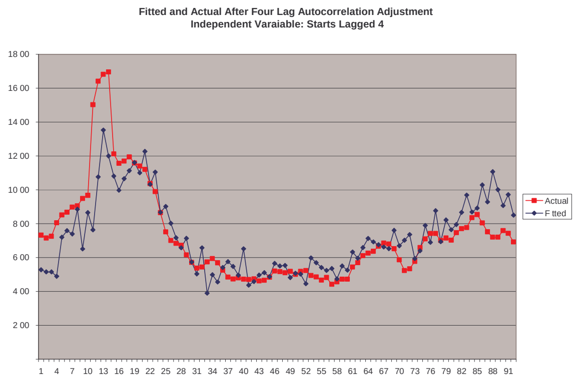
Customer Forecasts made by Other Utility Companies

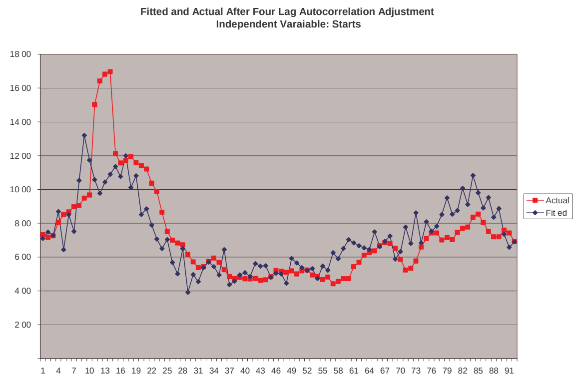
CMP’s approach to projecting customer growth is not the same as some other utility companies for which we have information. BHE for example simply computes the historic trend in customer growth. If CMP used this approach, forecast would be higher as CMP’s forecast is influenced by declines in the number of housing starts projected by Global Insight. Some of the other Energy East companies use exponential smoothing which is similar to trend analysis and does not incorporate information about the number of housing starts. Other Energy East companies use the number of households as the primary driver variable, but they do not appear to develop models from changes in the number customers as does CMP. Although CMP’s approach differs from the techniques used by other companies, we find the overall method reasonable as it incorporates both trending through inclusion of the lagged dependent variable as well as information about future housing starts.

Alternative Specifications for Customer Growth

We have analyzed CMP’s customer equation through investigating a number of alternative possible specifications. These specifications include not using a lagged dependent variable; performing the analysis on the number of customers directly rather than the changes in the number of customers; using lagged housing starts rather than current housing starts; not including an autocorrelation factor; and, using different independent variables including dummy variables.

To evaluate how variables affect the customer gains we removed the lagged dependent variable and we use a longer time period than the time frame used by CMP. When we evaluated equations that are derived from the number of customers instead of customer changes and tested how population or households rather affected the equation. These equations had very high R-squared of more than 99%, but they also had high autocorrelation. This implies that it is reasonable to perform the analysis using gains rather than the number of customers. In modeling the customer gains variable, the number of housing starts was more significant than other variables that we investigated. However, a variable measuring the lagged customer starts produces a better fit than the use of current starts. The two graphs below show relationship between fitted and actual data when current starts are used and lagged current starts are used. By comparing these two graphs in the early periods when there were large swings, one can see that lagged housing starts represent the data better than current housing starts.

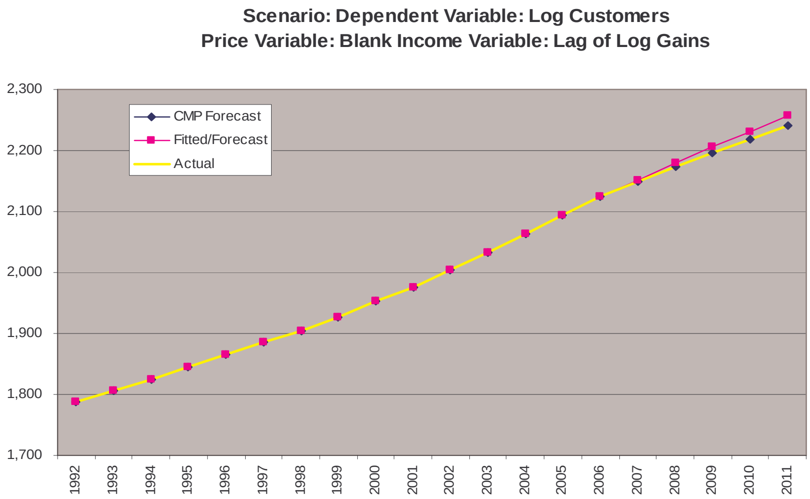




Recommended Forecast for Residential Customers

We recommend that the equation for computing the number of new customers use lagged housing starts and dummy variables for the ice storm and different quarters. Further, the equation should be estimated from data beginning in 1982 instead of 1990. Use of lagged housing starts rather than current housing starts is logical since there is a lag between the commencement of construction on a new home and the completion of construction when a new customer is recorded by CMP.

The alternate regression results in somewhat higher coefficients for both lagged customer gains and for lagged housing starts. The forecasted number of customers relative to the CMP forecast is shown in the graph below. Application of the alternative equation increases the number of new customers by 0.14%, 0.30%, 0.43%, 0.54% and 0.66% in 2007, 2008, 2009, 2010 and 2011.



4. VARIABLES OMITTED FROM CMP'S RESIDENTIAL SALES EQUATION

In this part of the analysis we discuss variables that were not included in the CMP regression equation of customer use. Statistical and forecasting problems that arise from omitted variables are described in the Appendix. The variables that CMP omitted and that we explicitly consider include historic energy savings from DSM and changes in space heat usage. There are other variables omitted variables in the CMP equation such as the average size of the housing stock and the number of vacation homes. However we did not have sufficient data to include these variables in the regression equation.

Omitted Demand Side Management Programs

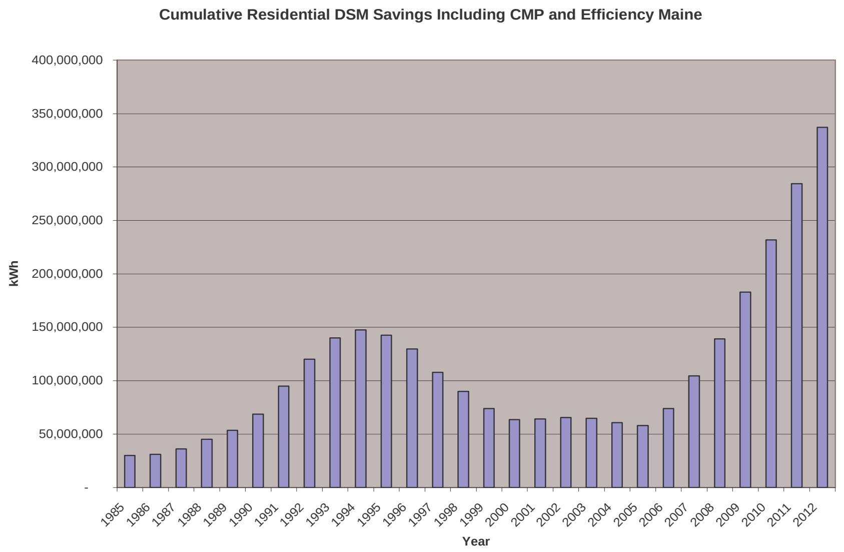
CMP accounts for the DSM programs administered by Efficiency Maine in its forecasts through subtracting the estimated future incremental savings from the forecast it developed from econometric equations. We agree that programs administered by Efficiency Maine affect CMP's sales forecast as the objective of the programs is obviously to save energy. However, because the approach ignores programs administered by CMP and programs administered Efficiency Maine, there is a bias in the forecast. The discussion below addresses the issue of how omission of historic DSM affects the regression equation and the forecast of use per customer. The discussion is divided into the following subjects:

- Compilation of historic DSM data
- Incorporation of historic DSM in the regression equations
- Implications of including historic DSM programs on the regression equation and the forecast

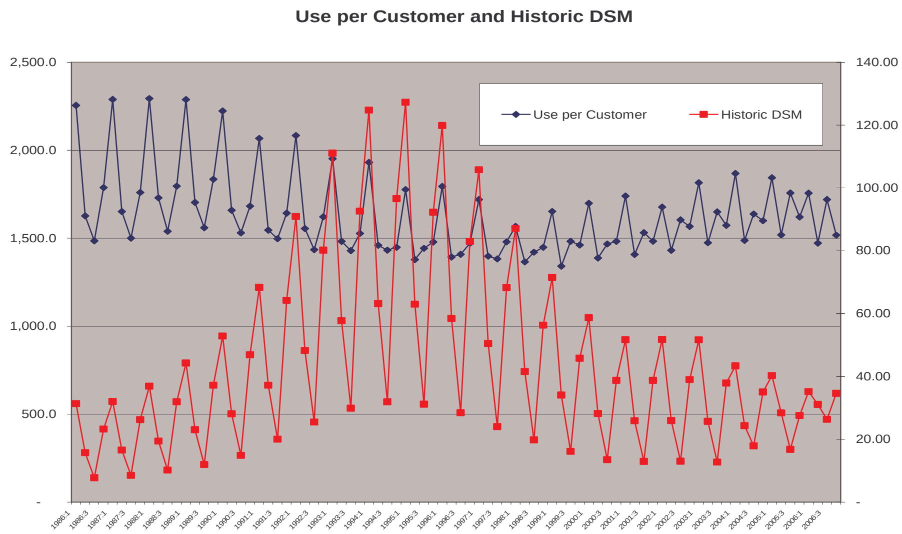
Historic DSM Data

When evaluating the effect of the omitted DSM savings on the regression equation, it is the energy savings that are important to consider, whether the energy savings came from programs administered by CMP itself of by Efficiency Maine. Further, the effect of expiring DSM savings must be reflected as well as the incremental new savings. To incorporate the historic DSM and the expiring DSM savings, we have created a data series that includes accumulated residential DSM savings arising from programs administered by the Company since 1985, the accumulated savings resulting from Efficiency Maine programs since 2003, and expiring savings from the programs. The expiring savings are computed through assuming programs have a life of six years. The source of the savings data prior to 1995 is from reports filed by CMP to the Commission; the source of subsequent savings from DSM programs is a data response provided by CMP and the source of Efficiency Maine savings is the cumulative DSM savings used by CMP in its update.

The accumulated DSM resulting from this analysis is shown in the graph below. The graph demonstrates that historic DSM programs peaked in the mid 1990's and then have declined. The Efficiency Maine programs eventually will accumulate to more than the historic DSM programs by the year 2010. To incorporate the DSM savings in the regression analysis, the annual DSM savings are allocated to quarters.



The graph below shows both the historic DSM programs and the CMP residential use per customer. This graph demonstrates that use per customer declined when DSM programs were high as expected. This implies that it may the DSM programs as well as the price, income or weather that are affecting the energy usage. If the DSM programs are ignored in the analysis, then estimates of coefficients for price income and weather will be biased.



Incorporation of Historic DSM in Regression Analysis

The historic DSM programs could be included as an independent variable in the regression equation. If this were done, one would expect that the coefficient of DSM per customer should be -1.0 as there should be a one for one relationship between energy savings and ultimate energy use. If this approach were used, the forecasted DSM would be modeled through plugging the DSM forecast into the regression equation as is the case with the income and price variable. We have run a regression equation where use per customer is the dependent variable and DSM is only independent variable. In this case, the coefficient on DSM is even higher in absolute value than 1.0. However, when other variables are added to the equation, the correlation between DSM savings and other variables the absolute value of the coefficient is reduced.

An alternative approach we adopt is to constrain the coefficient of DSM savings to -1.0 through adding the DSM savings per customer to the use per customer and then running the regression on a pre-DSM basis. This is accomplished through the following three step process:

Step 1: Add the historic DSM per customer to the residential use per customer in the historic time period used to estimate the regression equation
Step 2: Run regression analysis using pre-DSM customer use
Step 3: Subtract total DSM from the fitted values and projected values generated by the pre-DSM residential use regression equation.

We have applied this approach since it is reasonable to expect that energy savings from DSM programs have a one for one effect on customer use.

Incorporation of Historic DSM in Regression Analysis

When historic DSM is added to customer use, the forecast of customer use changes because regression coefficients are different and because the projected DSM incorporates expiration of historic DSM programs. To illustrate the effect of omitting the DSM variable, we have evaluated how the DSM approach above affects the forecast without making any of the other adjustments to the CMP forecast discussed above (i.e. no price elasticity, income, or weather effect.) When historic DSM is added to customer use, the regression equation has a higher R-squared and results in an increased forecast of customer use as shown in the table below:

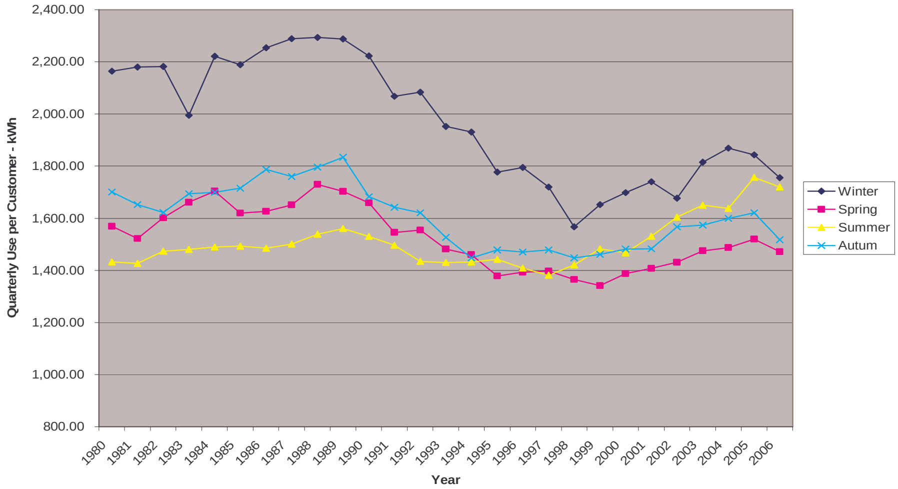
DSM Effect	
Year	Pct vs CMP
2007	1.89%
2008	1.94%
2009	2.17%
2010	2.75%
2011	3.25%

The ultimate effect of the DSM programs on the baseline forecast is discussed below in the sensitivity analysis section.

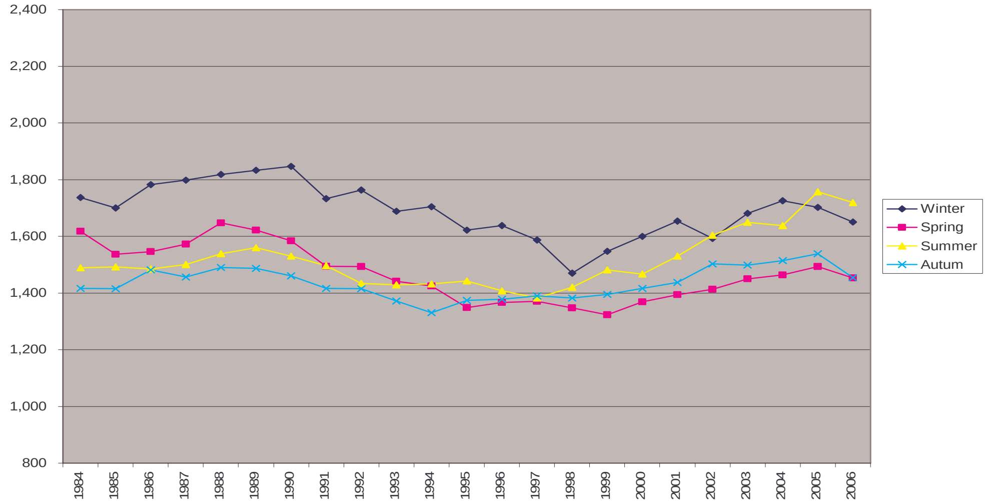
Omitted Space Heat Variable

Changes in electric space heat have had a large effect on CMP's historic sales because of the relative cost of electric and other sources of heat, new technologies and other factors. These factors are not included in CMP's econometric analysis implying that the equation has an omitted variable problem. The effect of changes in space heat and water heat are shown on the two graphs below. The first graph includes space heat while the second graph excludes space heat load. The space heat load is derived from data provided by CMP.

Quarterly Use per Residential Customer



Quarterly Residential Use without Space Heat



The two graphs above illustrate that the trends in residential sales change significantly when space heat is removed. As with DSM, the omission of space heat changes can affect the regression equation because space heat effects are attributed to other variables. When space heat is include in the regression equation, the coefficient is positive as expected and the ultimate forecast of sales increases. Alternatively, the space heat use can be constrained to have a one to one effect on sales. When this method is applied, the regression equation is made without space heat and then space heat sales are separately added to the forecast that results from the regression equation. This approach has a relatively small effect on the forecast.

5. FINAL BASELINE EQUATION AND SENSITIVITY ANALYSIS

In this part of the report we present our final recommended residential equation and sensitivity analysis on the regression equation. While the baseline forecast that we present contains our preferred forecast, we recognize that selection of some of the variables is subject to judgment and that alternative regression equations may be reasonable. The sensitivity analysis demonstrates that alternative reasonable equations produce forecasts that are similar or higher than our recommended forecast. This confirms that our forecast is reasonable.

Summary of Residential Baseline Forecast

The baseline residential sales forecast we recommend incorporates inclusion of the space heat, historic DSM, current rather than lagged prices, alternative distribution price forecasts, corrected income and alternative customer forecasts. In addition, the baseline equation does not include air conditioning saturation. Even though the air conditioning saturation variable increases the forecast, we have excluded it because of statistical problems. First, since the air conditioning saturation variable is closely correlated with the income variable it affects the significance of the other variables. Second the air conditioning variable contains errors in variables problems and the variable was not forecast on an objective basis.

After changing the CMP independent and dependent variables, the resulting regression is presented below. In this equation the t-statistics for the price variable and the income variable are somewhat below 2.0 whereas the t-statistics were above 2.0 in CMP's regression. The lower t-statistics result in part because there is less variation in the customer use variable when space heat is excluded from customer use.

Coefficients and t-Stasticis in Final Regression

	Coefficient	t-Stat
Log Alt Real Price	(0.09325)	-1.66
Log of Global Insight	0.16948	1.35
HDD	0.00005	4.12
CDD	0.00015	3.45
Ice Storm Dummy	(0.04709)	-2.76
First Quarter Dummy	0.08811	1.52
Second Quarter Dummy	0.02764	0.47
Third Quarter Dummy	0.13753	2.17

When space heat is left in the customer use definition, the coefficients are more significant as shown in the table below. This equation produces a forecast that is significantly higher than our baseline recommendation.

Coefficients and t-Stasticis in Final Regression

	Coefficient	t-Stat
Log Alt Real Price	(0.15092)	-2.15
Log of Global Insight	0.35828	2.26
HDD	0.00011	7.39
CDD	0.00017	3.23
Ice Storm Dummy	(0.04840)	-2.28
First Quarter Dummy	0.05073	0.67
Second Quarter Dummy	0.05215	0.69
Third Quarter Dummy	0.20496	2.50

The final forecast involves developing an equation for the log of customer use without space heat and without historic DSM. This forecast must be converted from logs and then space heat energy must be added and DSM must be reduced from the forecast. The table below summarizes components of the baseline forecast.

Forecast									
	Forecast LN Per Customer	Forecast Use per Customer	Number of Customers	Pre-DSM Pre-Space Heat Use	Space Heat Load Added	Sub-Total Before Adding DSM	Less: CMP DSM	Less: Historic DSM	Total Sales
2007	29.53	6,438.82	2,152.00	3,463,793	122,903.50	3,586,697	-	92,261	3,494,435
2008	29.53	6,448.27	2,179.60	3,513,398	122,334.91	3,635,733	-	125,343	3,510,390
2009	29.57	6,506.59	2,205.70	3,587,626	122,930.20	3,710,556	-	165,450	3,545,106
2010	29.60	6,554.40	2,231.31	3,655,947	124,274.11	3,780,221	-	212,290	3,567,932
2011	29.63	6,609.30	2,256.18	3,727,664	125,606.78	3,853,270	-	263,357	3,589,913

Sensitivity Analysis

In this section we present a sensitivity analysis that presents results of alternative variables and time periods. Some of the factors that we evaluate in the sensitivity analysis include:

- Leaving space heat in the regression analysis
- Using a price variable that is computed from the average of the prior four quarters rather than the current price
- Modeling DSM in the manner that CMP does rather than including historic DSM
- Including the Air Conditioning variable in the regression
- Not including dummy variables in the first and second quarter
- Using CMP projections of customer growth rather than the alternative number of customers

In addition to the above scenarios, we have included additional scenarios that include multiple changes in the variables. For each of the scenarios, we have evaluated how the scenarios change if different time periods are used to estimate the regression equations. The alternative time periods either begin earlier in 1984 or later in 1990. The table shown in the introductory section demonstrates the sensitivity analysis using the time period applied by CMP. The tables below show alternative scenarios with different time periods. As with the sensitivity shown in the introduction, data that are shaded represent scenarios in which the sales forecast exceeds our base case scenario. The tables below along with the sensitivity table presented in the introductory section show that there are many alternative reasonable scenarios that generate an even higher forecast than our baseline forecast confirming the baseline case is not unreasonably optimistic.

Residential Equation Scenario Analysis - 1990					
Year	2007	2008	2009	2010	2011
Scenario					
CMP Case	0.74%	1.08%	1.26%	0.90%	0.62%
Baseline Case	**3.58%**	**5.06%**	**6.22%**	**5.40%**	**4.90%**
Scenario 1: Include Space Heat	4.72%	6.20%	7.50%	6.80%	6.47%
Scenario 2: Price Variable with Average of Four Quarters	2.97%	4.22%	5.48%	4.94%	4.59%
Scenario 3: CMP Modeling of DSM	4.72%	6.51%	7.67%	6.42%	5.26%
Scenario 4: Air Conditioning Variable Included	4.14%	5.94%	7.01%	5.97%	5.09%
Scenario 5: Exclude 1st and 2nd Dummies	3.56%	4.97%	6.00%	5.08%	4.47%
Scenario 6: CMP Customer Equation	3.44%	4.74%	5.77%	4.82%	4.19%
Scenario 7: Average Price and Include Space Heat	3.48%	4.41%	5.67%	5.22%	4.96%
Scenario 8: Average Price, Space Heat and CMP DSM	1.44%	2.34%	3.51%	3.03%	2.79%
Scenario 9: A/C, Average Price, Space Heat and CMP DSM	2.42%	3.82%	4.82%	3.90%	3.07%
Scenario 10: Space Heat and A/C Included	5.37%	7.23%	8.34%	7.20%	6.17%
Scenario 11: Space Heat and No Dummies	4.57%	6.01%	7.34%	6.65%	6.33%

Residential Equation Scenario Analysis - 1984					
Year	2007	2008	2009	2010	2011
Scenario					
CMP Case	-0.17%	-0.25%	-0.27%	-0.18%	-0.10%
Baseline Case	**2.55%**	**3.70%**	**4.97%**	**3.99%**	**3.32%**
Scenario 1: Include Space Heat	4.33%	6.01%	8.31%	8.22%	8.53%
Scenario 2: Price Variable with Average of Four Quarters	1.70%	2.53%	3.76%	3.24%	2.78%
Scenario 3: CMP Modeling of DSM	3.78%	5.16%	7.32%	6.94%	6.92%
Scenario 4: Air Conditioning Variable Included	2.47%	3.64%	5.06%	4.11%	3.45%
Scenario 5: Exclude 1st and 2nd Dummies	2.67%	3.76%	4.96%	3.93%	3.21%
Scenario 6: CMP Customer Equation	2.41%	3.39%	4.52%	3.41%	2.62%
Scenario 7: Average Price and Include Space Heat	3.19%	4.43%	6.68%	7.28%	7.88%
Scenario 8: Average Price, Space Heat and CMP DSM	0.60%	1.46%	3.19%	3.34%	3.54%
Scenario 9: A/C, Average Price, Space Heat and CMP DSM	0.58%	1.45%	3.20%	3.37%	3.56%
Scenario 10: Space Heat and A/C Included	4.37%	6.18%	8.70%	8.73%	9.13%
Scenario 11: Space Heat and No Dummies	4.37%	6.05%	8.32%	8.22%	8.53%

Appendix 3

Case Study: Revenue Cap Regulation in Bulgaria

In 2003, the regulatory body in Bulgaria (then named SERC, since renamed SEWRC), decided to restructure certain tariff mechanisms in the energy sector.

In the course of the discussions within SERC and with various consultants, SERC began considering adopting a revenue cap approach to setting tariffs for utilities in the energy sector.

The issues raised during these discussions included the importance of establishing service and energy quality standards, and reporting of performance under those standards should be reported to SERC. In this context, both the views of the subject utilities and the requirements of the applicable laws and regulations were considered. The variety of issues and scope of disagreement on how to handle service quality issues is an indication of the complexity of this aspect of price cap (and performance-based) regulation. What follows is a summary of the discussions, with the identity of the proponent removed:

> The initial discussion focused on the proposed service and energy quality standards and the reporting to the SERC by the Distribution Companies (EDCs).
>
> Mr. A gave an explanation of each indicator: quality of electric power, continuous supply and trade service quality, necessity of determining maximum and minimum indicator values. Since no data of continuous electricity supply to end consumers are available, SERC and EDCs need to think how to obtain the data in the future.
>
> Comments and questions about the indicators included:
>
> Should relative or absolute indicator values be used? The project values are relative and do not present a clear picture. For example, one of first indicators, "average time for a written response," has no quantitative value associated with it. Should it reflect the number of days required to settle a matter or the number of complaints? Proposed indicators such as "average interruption duration" ("SAIDI") are currently calculated, but average values are used and therefore indicators are inaccurate.
>
> Mr. B suggested that the existing approach for determining the indicators for energy quality and quality of services are obsolete. Instead, a quality management system, which would permit monitoring and control of final results, should be introduced.
>
> Mr. C responded and suggested that, for a variety of reasons, using average performance indicators may be preferable. For example, individual guarantees require good technical equipment and computer systems, for which the companies do not have sufficient financing.
>
> Another issue raised in the discussions was whether, for voltage deviations,

average measurements should be taken for each customer, or whether the reporting requirement should cover only customers affected by voltage deviations. In either case it would be important to establish baselines and the develop indicators to be improved where necessary. The standards could be differentiated based on the character of the service territory: urban, semi-urban or rural.

In addition, some range of tolerance around any particular standard would need to be established.

The group then turned to how the service quality standards would be incorporated into the revenue cap formula. One participant proposed the following approach:

Required revenue = (expenditures + rate of return) x (1 + inflation factor – efficiency improvement factor) +/- Z

- The efficiency improvement factor during the first period (one year) is zero
- Z is combination of two factors:
    1. adjustment of purchased electricity costs
    2. adjustment of target values, which will not be fixed precisely

In this formula, the penalty value could be increased where the company has not improved its targets.

Following these extensive discussions, the consultants prepared draft documents, including a proposed method for the annual price adjustments under the revenue cap regulation, to the SEWRC Working Group. Further discussions took place concerning next steps and the development of tables for annual reporting of the indicators used in the annual adjustments, including examples of the determination of the “X” factor in the revenue cap regulation formula.

The SEWRC ultimately adopted revenue cap regulation for its electric distribution company. The basis of the financial information for tariffs is Uniform System of Accounts. The reporting forms for each type of licensee for tariff applications are posted on the website of the SEWRC. The tariff methodology embodying the SEWRC determinations is included as Attachment 1 to this case study.

Appendix 3 - Attachment 1

SERC Directions for
electric d...

STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2007-215

CENTRAL MAINE POWER COMPANY,
REQUEST FOR NEW ALTERNATIVE RATE PLAN
("ARP 2008")

Central Maine Power

An Energy East Company

TESTIMONY OF
JOHN P. DAVULIS

Volume II
SALES FORECAST

May 1, 2007

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May 1, 2007

SALES FORECAST

I. INTRODUCTION AND OVERVIEW

The reasonableness of CMP's current rates depends, in significant part, on the revenues those rates are expected to produce. Any calculation of those expected revenues is, in turn, heavily dependent upon an estimate of the load over the period during which the rates are expected to be in effect – in CMP's proposal in this proceeding, the period of the proposed new alternative rate plan ("ARP"). In developing the data showing the financial performance of CMP under the ARP as proposed, CMP prepared a sales forecast for the years 2007 through 2011. The forecast presented in this testimony builds upon, but also incorporates significant improvements recommended by the Company's consultand, Concentric Energy Advisors, relative to, the forecast presented by CMP in MPUC Docket No. 2005-729. As shown below, the CMP forecast presented in that case has been largely justified by actual load experience during 2006. The forecast presented here has been enhanced to ensure that the strong performance of the model continues, and, if anything, presents a conservative (i.e., "high") projection of CMP's sales growth over the period.

A. <u>Qualifications of Witness</u>

CMP's sales forecast was prepared by John Davulis, who is a Lead Analyst in the Pricing and Analysis Services Department. Mr. Davulis is the chief economist at Central Maine Power. In this capacity, he is responsible for the preparation of CMP economic and sales forecasts. He directs staff activities related to developing economic models for short-term sales and peak load forecasting. He authors a monthly analysis of sales variances and manages a variety of research projects.

Mr. Davulis has more than 30 years experience in economic modeling, short and long-term forecasting, economic analysis and program management. He has previously provided testimony before the Maine Public Utilities Commission on issues related to the Company's sales and peak load forecasts and other economic matters, most recently in Docket No. 2005-729.

Mr. Davulis holds a B.A. in Philosophy from the University of New Hampshire, an M.A. in Philosophy from the University of Cincinnati, an M.S. in Resource Economics from the University of New Hampshire, and a Graduate Certificate in International Business from the University of Maine.

Since 1987, Mr. Davulis has been a member of the NEPOOL Load Forecasting Committee and served as its Chair from 1998-2000. Since 1993, he has served on the State of Maine's Consensus Economic Forecasting Commission. He has been a member of the Board of Directors for the Maine Energy Education Program since 1999. A more complete professional and educational background of Mr. Davulis is provided in Exhibit SF-1.

B. Purpose of Testimony

In this testimony, CMP presents a general overview of its Winter 2007 sales forecast used to determine expected distribution revenues which are used in CMP's revenue requirement analysis contained in the testimony of Messrs. Stinneford and Dumais. Table SF-1 summarizes the results of the Winter 2007 sales forecast. A detailed description of the forecast methodology, assumptions, and results is provided in Volume III, Economic Outlook, Methodology and Sales Forecast. Volume IV presents an independent review of CMP's sales forecast and methodology performed by James Coyne and James Simpson of Concentric Energy Advisors, Inc. ("Concentric"). In light of the concerns relating to CMP's load forecast raised in MPUC Docket No. 2005-729, CMP engaged Concentric to review its forecast assumptions and methodologies used to prepare its sales forecast. As discussed in detail in Volume IV, in the course of the firm's evaluation of CMP's residential forecast, Concentric helped identify an improved econometric model for projecting residential kWh use per customer, and that model serves as the basis for CMP's Winter 2007 sales forecast.

The Commission should rely on CMP's Winter 2007 sales forecast, which is summarized in Table SF-1. Concentric has thoroughly reviewed CMP's forecasting approaches and the resulting sales forecast and has concluded that the Winter 2007 sales forecast is reasonable. Moreover, with the potential for additional conservation from increased Efficiency Maine funding and CMP's installation of an advanced metering infrastructure ("AMI") system, funding, actual sales amounts could be lower.

CMP generally prepares a five-year sales forecast in the Fall of each year. The Company relies on the forecast to project revenues for general planning purposes. In preparation for this proceeding, the Fall 2006 sales forecast was updated in February 2007 in order to incorporate: (i) an improved econometric model for forecasting residential kWh sales that was developed with the assistance of Concentric; (ii) actual sales results for the second half of 2006; (iii) a new electricity price forecast that captures the most recent standard offer prices and current supply price estimates; (iv) Global Insight's U.S. and Maine economic forecast available in January 2007; and (v) updated sales information for a few large customers. All statistical equations used in preparing the sales forecast were recalculated using up-to-date sales, price and economic data.

Table SF-1. Annual Sales (mil. kWh) by Class, Winter 2007 Forecast

	Total	Residential	Commercial	Industrial	Lighting	Wholesale
1990	9,212.8	3,087.4	2,316.7	3,657.8	36.7	114.2
1991	9,106.5	2,977.5	2,326.7	3,651.2	35.6	115.5
1992	9,181.7	2,989.4	2,365.9	3,672.1	35.6	118.7
1993	9,216.9	2,884.3	2,386.9	3,791.0	35.2	119.5
1994	9,167.6	2,859.7	2,438.9	3,719.7	35.0	114.3
1995	8,961.8	2,802.2	2,476.8	3,546.5	34.9	101.5
1996	9,222.1	2,828.9	2,487.9	3,688.5	34.7	182.1
1997	9,354.0	2,816.5	2,526.2	3,783.1	34.7	193.4
1998	9,050.2	2,760.3	2,561.3	3,486.9	34.7	207.0
1999	9,211.4	2,859.4	2,701.0	3,568.4	34.8	47.6
2000	9,428.0	2,946.7	2,813.2	3,633.1	35.0	0.0
2001	9,258.6	3,043.8	2,930.8	3,248.8	35.3	0.0
2002	8,705.5	3,147.4	3,000.3	2,522.3	35.5	0.0
2003	8,939.0	3,308.1	3,070.1	2,525.0	35.8	0.0
2004	9,223.8	3,399.8	3,144.3	2,643.5	36.2	0.0
2005	9,346.8	3,529.1	3,217.3	2,564.0	36.5	0.0
2006	8,955.2	3,431.4	3,207.1	2,279.8	36.8	0.0
2007	8,673.3	3,423.0	3,280.1	1,933.0	37.1	0.0
2008	8,770.7	3,415.8	3,374.1	1,943.2	37.5	0.0
2009	8,858.9	3,433.2	3,462.9	1,924.9	37.9	0.0
2010	8,963.5	3,512.7	3,514.4	1,898.1	38.2	0.0
2011	9,063.8	3,583.4	3,567.2	1,874.7	38.6	0.0

Percent Change in Annual Electricity Sales by Class

	Total	Residential	Commercial	Industrial	Lighting	Wholesale
1991	-1.2%	-3.6%	0.4%	-0.2%	-3.0%	1.1%
1992	0.8%	0.4%	1.7%	0.6%	0.0%	2.8%
1993	0.4%	-3.5%	0.9%	3.2%	-1.1%	0.7%
1994	-0.5%	-0.9%	2.2%	-1.9%	-0.5%	-4.4%
1995	-2.2%	-2.0%	1.6%	-4.7%	-0.4%	-11.2%
1996	2.9%	1.0%	0.4%	4.0%	-0.6%	79.4%
1997	1.4%	-0.4%	1.5%	2.6%	0.3%	6.2%
1998	-3.2%	-2.0%	1.4%	-7.8%	-0.2%	7.0%
1999	1.8%	3.6%	5.5%	2.3%	0.4%	-77.0%
2000	2.4%	3.1%	4.2%	1.8%	0.5%	-100.0%
2001	-1.8%	3.3%	4.2%	-10.6%	0.7%	0.0%
2002	-6.0%	3.4%	2.4%	-22.4%	0.7%	0.0%
2003	2.7%	5.1%	2.3%	0.1%	0.9%	0.0%
2004	3.2%	2.8%	2.4%	4.7%	1.0%	0.0%
2005	1.3%	3.8%	2.3%	-3.0%	0.7%	0.0%
2006	-4.2%	-2.8%	-0.3%	-11.1%	1.1%	0.0%
2007	-3.1%	-0.2%	2.3%	-15.2%	0.7%	0.0%
2008	1.1%	-0.2%	2.9%	0.5%	1.0%	0.0%
2009	1.0%	0.5%	2.6%	-0.9%	1.0%	0.0%
2010	1.2%	2.3%	1.5%	-1.4%	1.0%	0.0%
2011	1.1%	2.0%	1.5%	-1.2%	1.0%	0.0%
CAGR* 2006-11	0.2%	0.9%	2.2%	-3.8%	0.9%	

**Compound Annual Growth Rate*

This Winter 2007 sales forecast narrative is organized as follows:

1) summary of 2006 sales results and comparison with prior forecast;
2) overall summary of the Winter 2007 sales forecast;
3) discussion of key economic factors affecting the sales forecast;
4) consideration of other key assumptions (e.g., weather, price of electricity, conservation); and
5) description of the forecast for each major class of service (residential, commercial, industrial and lighting).

C. Review of Sales Results in 2006

For the calendar year ending December 2006, total electricity sales (8,955 million kWh) were down 4.2%, or 392 million kWh, compared to 2005. In the aggregate, the Company's kWh sales in 2006 were slightly lower overall than what was anticipated in its Fall 2005 sales forecast.[1] However, there are significant variances across classes.

As shown in Table SF-2, total sales for 2006 were 0.5 million kWh less than projected in the Fall 2005 forecast. Year-end residential sales were 98 million kWh (-2.8%) less than 2005 and 34 million kWh (-1.0%) less than projected in the Fall 2005 forecast.[2] The commercial class showed a ten million kWh (-0.3%) drop from 2005, with sales being 91 million kWh below the Fall 2005 forecast. While sales to industrial

[1] The Fall 2005 sales forecast was used by CMP as its sales forecast in MPUC Docket No. 2005-729, Request for Extension of Alternative Rate Plan (ARP 2000 Extension).

[2] In Docket No. 2005-729, the Bench Analysis recommended a residential forecast of 3,532 million kWh be adopted for 2006. In hindsight, the Staff's forecast overestimated 2006 residential sales by 100 million kWh, or by 2.9%.

customers were 269 million kWh (-11.1%) below 2005, they were 108 million kWh higher than estimated in the Fall 2005 forecast.

Table SF-2. Sales Variance, Actual 2006 vs. Fall 2005 Forecast

	2006 Year-End Sales (MWh)			Percent Growth	
	Actual	Forecast	Variance	Actual	Forecast
Residential	3,431,361	3,465,439	(34,078)	-2.8%	-1.8%
Commercial	3,207,115	3,297,792	(90,677)	-0.3%	2.5%
Industrial	2,279,827	2,155,619	124,208	-11.1%	-15.9%
Paper	729,399	621,679	107,720	-26.9%	-37.7%
All Other	1,550,428	1,533,940	16,488	-1.0%	-2.0%
Lighting	36,848	36,768	80	1.1%	0.9%
Total Sales	8,955,151	8,955,618	(466)	-4.2%	-4.2%

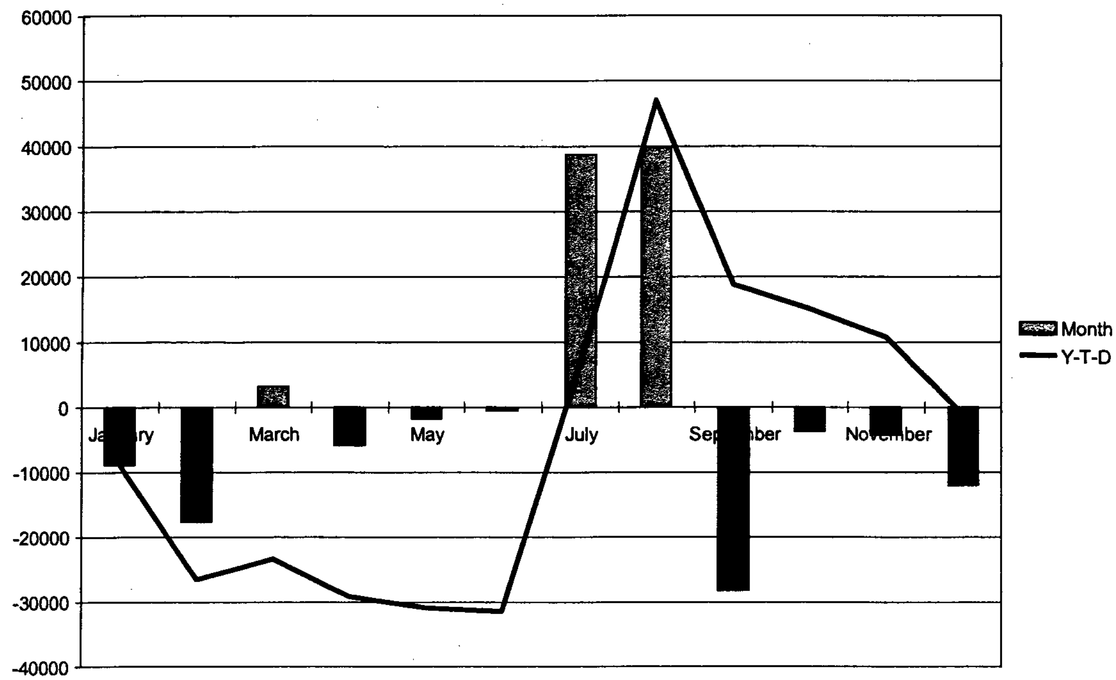
Some of the major factors influencing 2006 sales results are as follows:

Weather conditions during heating season. On a billing-cycle basis, the number of heating degree days (6,355) was 12% less than 2005 and 9% less than the normal weather assumed in preparing the Fall 2005 sales forecast. Compared to forecast, sales to residential and commercial customers were 55 million kWh below expectations due to the occurrence of warmer-than-normal temperatures.

Weather conditions during cooling season. On a billing-cycle basis, the number of cooling degree days (432) was 11% less than 2005 but 15% greater than the normal weather assumed in developing the Fall 2005 sales forecast. Compared to forecast, electricity sales to residential and commercial customers were 54 million kWh above expectations due to the occurrence of hotter and more humid weather.

The following chart provides a perspective on the impact of 2006 weather conditions on sales compared to the normal weather assumed in the forecast. On a net basis, there was little kWh impact of the abnormal weather that occurred in 2006.

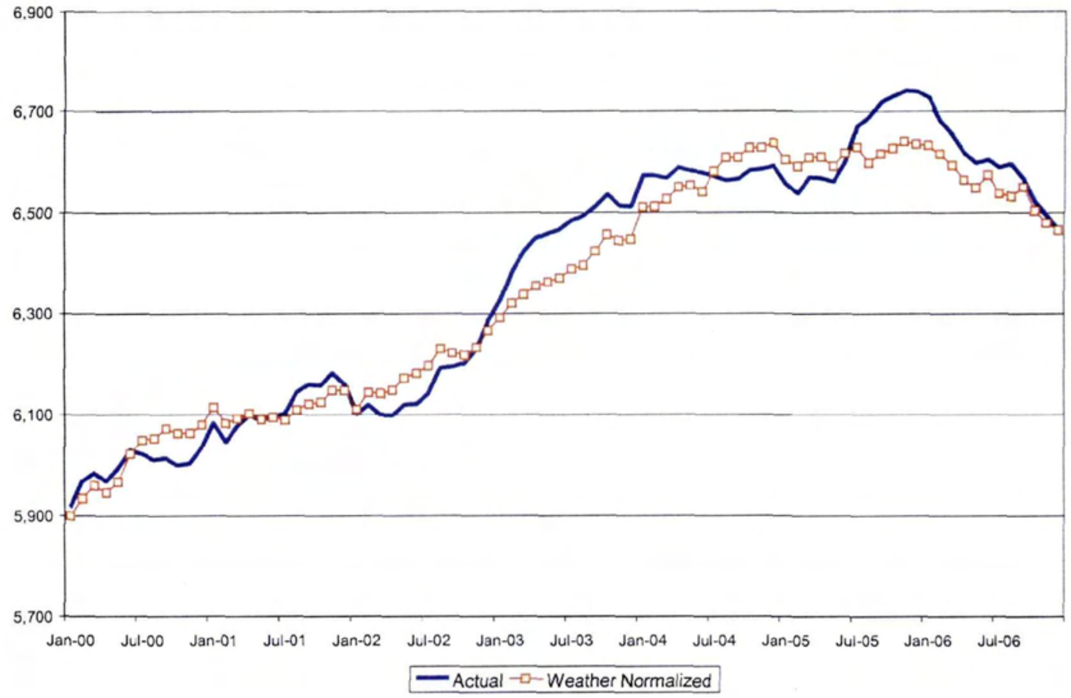
Table SF-3. Impact of Weather on 2006 Sales (MWh) vs. Normal Weather



<u>Residential customer growth</u>. For the 12-month period ending December 2006, 6,563 (or +1.3%) new residential accounts were added to CMP's rolls. This is slightly less than the Fall 2005 forecast's estimate of 6,870. The number of new customers added to CMP's rolls has slowed from about 7,800 in 2004-2005 due to a slowdown in housing construction.

<u>Annual usage per residential customer</u>. For the 12-month period ending December 2006, average annual residential electricity usage per customer stands at 6,463 kWh. Over the past 12 months, annual usage per customer has decreased by 277 kWh (or -4.1%). CMP's Fall 2005 sales forecast called for residential usage to approach 6,529 kWh by year-end. As shown in Table SF-3, on a weather-normalized basis, the decrease in average customer usage is somewhat less. Adjusted for weather anomalies, average usage is down -2.5% from 2005.

Table SF-4. Average kWh Use per Residential Customer 12-Month Moving Average



<u>Growth in personal income</u>. Data for the 3rd Quarter of 2006 indicate that personal income in Maine grew at an annual rate of 5.9% on a year-over-year basis, which is less than the comparable growth rate for the U.S. (6.7%). Although the personal income of Mainers is advancing, the rate of growth is slower than the Global Insight projection used to prepare the Company's Fall 2005 sales outlook. The slower-than-expected rate of increase in personal income affects both residential and commercial usage.

<u>Consumer borrowing</u>. While data is not available for Maine, national data indicate that the rate of increase in the amount of debt that consumers are willing to incur is slowing. Consumer debt load (home mortgages outstanding plus other consumer debt) as a fraction of disposable personal income was 128.6% as of the 4th Quarter of 2006. Over the past year, the debt ratio has risen by only 2.6%. By contrast, between 1990 and 2005, the debt ratio increased by an average of 6.3% per annum.

Residential real estate market. After increasing in value by 56% between 2001 and 2005, the median sales price of existing single family homes in the Portland metropolitan area decreased by 1.1% in 2006. Portland was ranked by the National Association of Realtors as the 23rd worst real estate market (out of 150 metropolitan areas). Consumers' ability to borrow on the increasing equity of their homes suffered a setback in 2006.

Price of electricity. The average bundled price of electricity paid by residential customers increased by 12% in 2006. The comparable increase for commercial customers was 22% and for industrial customers was estimated at 41%. Consumers have reduced their kWh usage in response to rising prices. 2006 was the second consecutive year in which the price of electricity rose significantly due to increases in supply prices.

General economic conditions. Over the 12-month period ending December 2006, total wage and salary employment in Maine grew by only 1,400 jobs (or +0.2%). (CMP's service territory provides about 78% of Maine's jobs.) While 1,300 manufacturing jobs (or -2.1%) were lost in the past year, commercial employment advanced by 2,700 jobs (+0.5%). The fastest growing segments were Construction (+1.6%), Education and Health Services (+1.4%), and Business and Professional Services (+1.2%). The amount of employment growth that occurred was less than what Global Insight had projected (i.e., 6,700 jobs). Overall, in terms of employment growth, only five states (Michigan, Ohio, Indiana, Wisconsin and Vermont) experienced slower job growth than Maine.

Loss of a large paper industry customer. Electricity sales to the paper industry were reduced by the loss of a large customer, whose full service customer agreement with CMP expired in 2005. In 2006 that customer provided for most of its electricity needs through its own generating capability. Sales to non-paper industrial customers were stronger than expected.

D. <u>Summary of the Sales Forecast, 2007-2011</u>

Total electricity sales in 2007 are projected to decrease by 3.1% to 8,673 million kWh the 2006 level of 8,955 million kWh. Sales increases on the order of 1.0-1.2% per year are anticipated for the 2008-2011 period. The sales decline in 2007 is largely the result of the loss of an additional large customer upon the expiration of its full service customer agreement with CMP.

As shown in Table SF-1 above, residential sales are estimated to be flat through 2009 and to grow at 2.0-2.3% per year thereafter. Although modest customer growth is expected to occur, annual kWh usage per customer is projected to decline over the 2006-2009 period. After 2008 the price of electricity is projected to decline – encouraging average customer usage to rise in 2010 and 2011.[3] As previously stated, based upon Concentric's recommendation, CMP has incorporated a new econometric approach for forecasting kWh usage per customer.

[3] Based upon its statistical analysis of customer behavior over time, CMP believes that there is a one year delay in the response of residential customers to a change in the price of electricity. Commercial and industrial customers respond more quickly to price changes.

Following a 2.8% decrease in CMP's residential sales in 2006, the projected annual compound rate of increase in residential sales between 2006 and 2011 is 0.9% per annum. By contrast, CMP's residential sales grew by 3.5% per year between 1998 and 2004. The primary factors explaining the slower sales growth in the future are energy conservation, sluggish demographic growth and increases in the price of electricity.

Without energy conservation program savings, CMP's residential sales growth rate would be 1.5%. Over the five-year forecast horizon, CMP expects that planned Efficiency Maine programs will reduce residential electricity consumption by about 346 million kWh.

Another factor is slower demographic growth. Between 1998 and 2004, Maine population grew by 0.7% per year; on average, there were 6,700 new housing starts annually, and the number of CMP residential customers increased by 1.4% per annum. Looking forward, Global Insight projects that Maine's rate of population growth will slow to 0.3% per year 2006-2011, and housing starts will average only 5,500 over the forecast horizon. As a consequence, the rate of increase in the number of CMP's residential customers will slow to 1.1% per year.

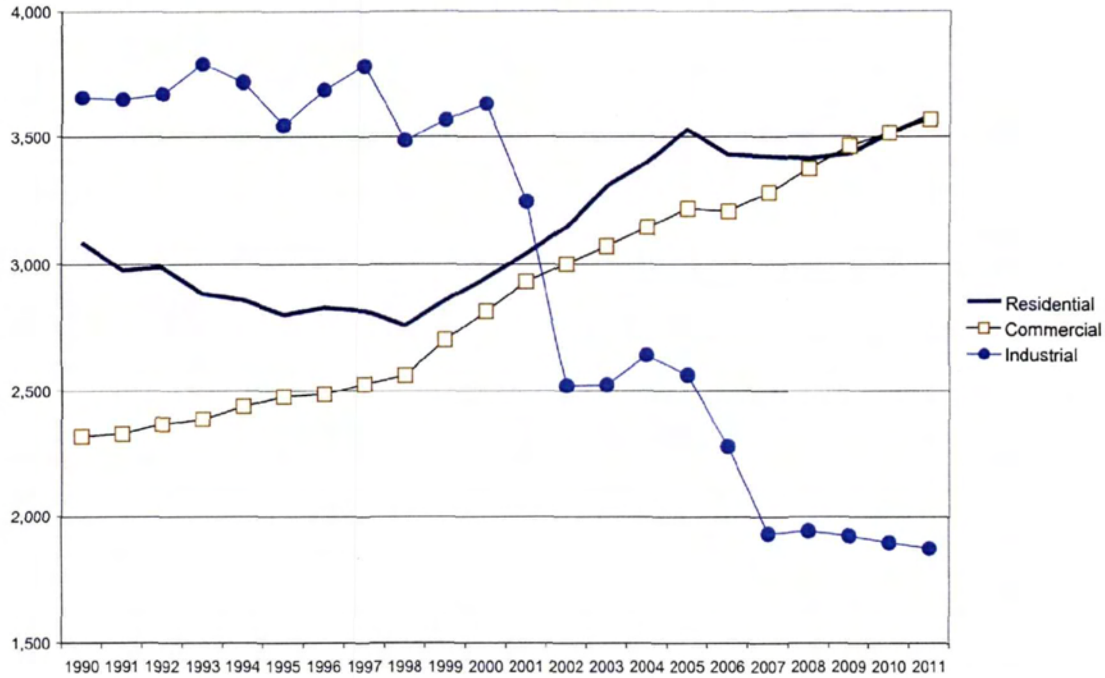
A third important factor is related to the price of electricity. Between 1998 and 2004, the residential price of electricity, adjusted for inflation, decreased at an annual rate of 3.8% per year. Residential prices rose in 2005 and 2006. The annual increase in the price of electricity, adjusted for inflation, over the 2004 to 2006 period was +8.8% per year. In part, as a result of these price increases, the rate of growth in residential sales fell to 0.5% per annum, 2004-2006; weather-normalized, the rate of increase was only 0.1% per year. CMP's Winter 2007 forecast estimates that the residential price of electricity, adjusted for inflation, will decrease slightly over the 2006 to 2011 time period by 2.0% per year and that residential sales growth will improve slightly once consumers believe that the dramatic price increases seen in the mid-2000s are unlikely to be repeated in the near term.

Commercial sales are projected to grow by 2.2% per year during the 2006-2011 period, due in large part to new customer growth in 2007-2008. Without the energy conservation savings associated with Efficiency Maine programs, CMP's commercial sales growth rate would be 3.4%. By comparison, commercial sales grew at an annual rate of 3.5% per year between 1998 and 2004.

Sales to industrial customers are estimated to decline by 3.8% per annum during the same 2006-2011 period, due to the significant decline in sales to a large customer in 2007. Overall, total CMP sales to all classes are projected to grow by 0.2% per year between 2006 and 2011.

Table SF-5 presents the forecast in a historical context. In 1990, the residential class accounted for about 34% of total CMP sales. By 2006, that percentage had risen to 38%. The Winter 2007 forecast calls for the residential portion of total sales to increase to about 40% by 2011. Sales to commercial customers rose from 25% of total kWh sales in 1990 to 36% in 2006 and are projected to reach 39% in 2011. By contrast, industrial class sales have fallen from 40% of total in 1990 to 26% in 2006, and, in 2011, are expected to drop to 21%. As indicated above, the primary factor explaining the drop in industrial sales is the expiration of customer service agreements with paper companies that have self-supply options. The paper industry aside, kWh sales to other industrial customers fell by 0.9% per year over the 2000-2006 period.

Table SF-5. Electricity Sales (mil. kWh) by Major Customer Class, Winter 2007



II. MAJOR ASSUMPTIONS OF THE SALES FORECAST

A. Economic Outlook

The foundation for CMP's sales forecast is the Global Insight economic outlook for the State of Maine. Global Insight (formerly DRI) is the economic consultant that CMP has used for more than two decades. Detail on Global Insight's economic forecast for Maine and the U.S. is provided in Volume III. The Winter 2007 sales forecast used the most recent economic projections available when CMP prepared the forecast. In particular, CMP used Global Insight's January 2007 economic forecast for the United States and its Winter 2007 regional forecast for Maine, which was released on January 29, 2007.

In the absence of other changes, economic growth determines the demand for electricity. Based upon the changes in the level of economic activity (number of residential customers, personal income, commercial and industrial output), CMP computes changes in electricity demand. CMP modifies these estimates where relevant information is available (such as weather, changes in the price of electricity, self-generation, mandated efficiency standards, information from customer interviews).

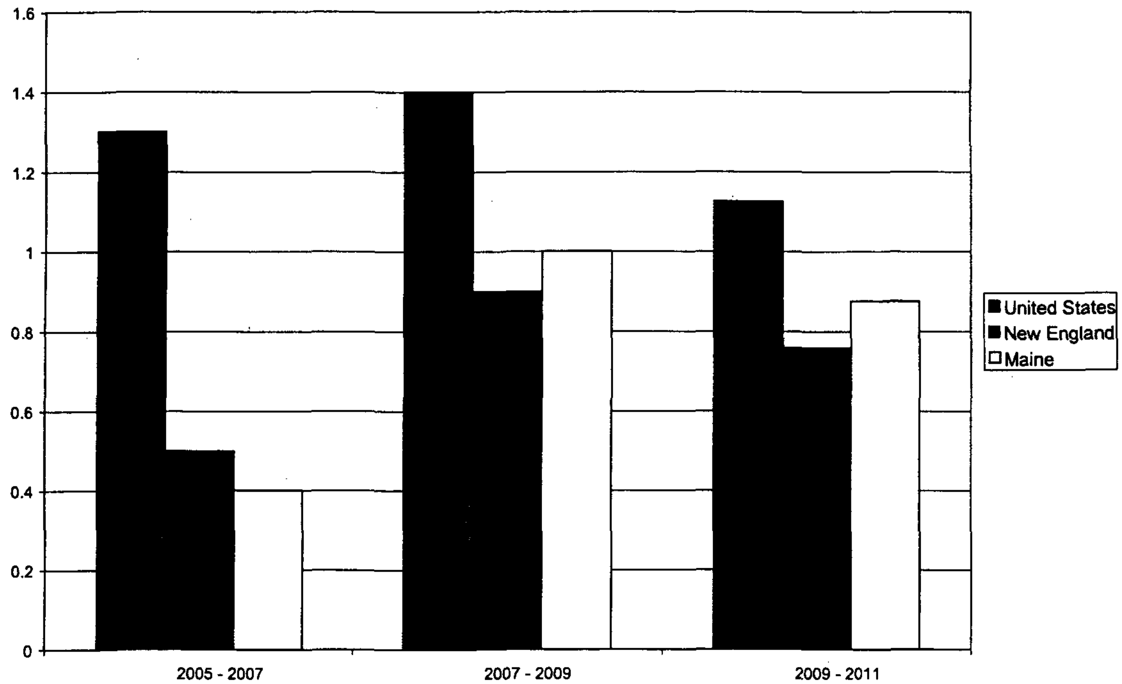
For its commercial and industrial sales forecast, CMP uses a disaggregated, segment-based forecasting approach that integrates the economic projection prepared by Global Insight with information obtained from interviews with large commercial and industrial customers. For large customers, CMP generally uses the information obtained from customer interviews for 2007 and 2008 and then uses Global Insight's output growth rates to forecast sales for 2009-2011. For small customers, CMP uses Global Insight's output growth rates to forecast sales for all years.

The key economic parameters are Global Insight's forecast of commercial and industrial output, adjusted for inflation, for more than 40 business segments. In addition to the Global Insight outlook, CMP account representatives conduct interviews with large commercial and industrial customers to gather information on the operating and expansion plans of the companies. Customer plans are affected by the expected demand for their product, the cost of doing business in Maine (including energy, labor and regulatory costs), foreign competition, their parent companies' corporate strategy, and other such factors. During the Spring of 2006, CMP account representatives conducted interviews with 77 commercial establishments representing approximately 30% of its total commercial class sales. Further, interviews were conducted with 87 manufacturers that account for more than 85% of CMP's total industrial class sales.

CMP's forecast explicitly recognizes past and future differences in economic/demographic growth between CMP's service territory and the rest of Maine as projected by Global Insight. The economy represented by CMP's service area is expected to grow slightly faster than Maine as a whole.

As shown in Table SF-6, Global Insight expects that the Maine economy will experience modest economic growth during the next five years. The rate of job growth in Maine for the 2006-2011 period is estimated to be 0.8% per annum vs. 1.3% for the nation. Among states, Maine ranks 44th in terms of expected employment growth, according to Global Insight.

Table SF-6. Global Insight's Forecast for Annual Employment Growth, Winter 2007



Global Insight projects that nonmanufacturing employment in the State will grow by about 6,200 jobs per year between 2006 and 2011, while manufacturing positions will decline by about 900 annually over the same period. In total, annual employment gains are expected to average 5,300. This is about one-half the rate of job creation experienced by Maine during the economic expansion that spanned 1992-2001.

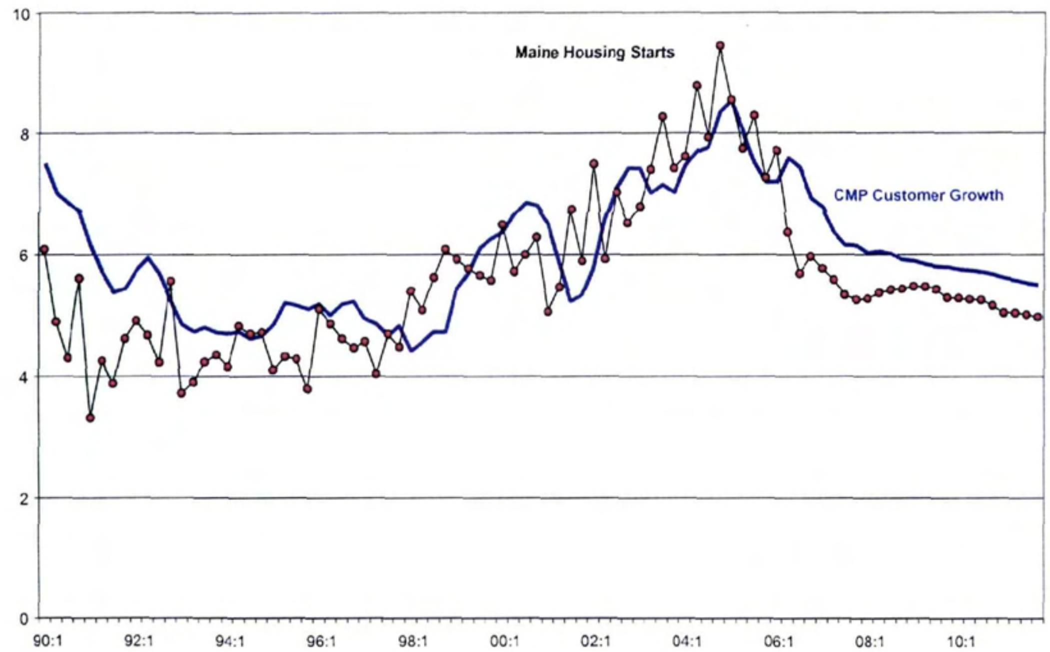
Employment in the nonmanufacturing side of the Maine economy is projected to advance at an annual rate of 1.1% compared to 1.5% for the U.S. as a whole. The fastest growing sectors are expected to be Professional and Business Services, and Education and Health Services. Adjusted for inflation, total commercial output is expected to grow by 3.1% per year over the forecast horizon.

Based on Global Insight's forecast, manufacturing employment is projected to decline at an annual rate of 1.5% between 2006 and 2011. While the number of manufacturing jobs is projected to decrease, real industrial output is projected to remain relatively stable over the forecast period. Improvement in worker productivity associated with capital investment will allow industrial output to remain about the same even with a decrease in labor input.

Key economic/demographic parameters which drive the residential sales forecast include housing starts and real income per customer. CMP uses Global Insight's projection of housing starts to develop a forecast of growth in the number of residential customers. All other factors held constant, a one percent increase in the number of customers will yield a one percent increase in residential sales.

Global Insight estimates that Maine's modest population growth of 0.3% per annum will support the construction of about 5,500 homes annually. New housing starts are used in CMP's model to calculate growth in residential customers. The number of housing starts in Maine peaked at an annualized rate of 9,450 in late 2004 and is projected to decrease during the forecast period to 4,960 in late 2011. As a result, growth in CMP residential customers will slow down in the years ahead, as shown in the following chart.

Table SF-7. Relationship Between Housing Starts and Residential Customer Growth (thous.)



Also important to the residential outlook is Global Insight's forecast for growth in income per customer, adjusted for inflation. Based on a CMP statistical analysis, a one percent increase in the average income per year-round customer will yield a 0.26 percent increase in average kWh usage.

Global Insight estimates that personal income, adjusted for inflation, will advance at 2.8% per annum from 2006 to 2011, with income per year-round customer growing at about 1.7% per year. The corresponding real personal income growth rate for the U.S. is 3.7%.

In summary, the Global Insight forecast for Maine calls for slow but sustainable economic growth in the years ahead. The outlook is dampened by the lack of a significant high tech sector in the State as well as by slow population growth. Table SF-8 provides a comparison of Global Insight's forecast with three other economic forecasts for Maine: one prepared by the Consensus Economic Forecasting Commission, another prepared by the Maine State Planning Office, and a third developed by Colby College.

Comparing the employment and income forecasts, Global Insight's projection calls for the strongest growth. To the extent that the other economic forecasts prove more accurate than the Global Insight forecast used in CMP's sales projection, the Company's Winter 2007 sales outlook will overstate CMP's sales over the life of ARP 2008.

Exhibit SF-8. Comparison of Global Insight's Winter 2007 Economic Outlook for Maine with Other Forecasts

Wage & Salary Employment (Thousands)	2005	2006	2007	2008	2009	2010	2011	CAGR 2005-11	CAGR 2006-11
Global Insight	611.6	613.6	616.8	621.7	629.0	635.2	640.1	0.8%	0.8%
Pct. Ch. Ann. Rate	0.0%	0.3%	0.5%	0.8%	1.2%	1.0%	0.8%		
Consensus Economic Forecasting Commission	611.7	615.0	619.1	623.8	628.5	632.6	636.1	0.7%	0.7%
Pct. Ch. Ann. Rate	0.0%	0.5%	0.7%	0.8%	0.8%	0.7%	0.6%		
Maine State Planning Office	611.6	614.5	618.8	621.9	626.9	632.5	638.2	0.7%	0.8%
Pct. Ch. Ann. Rate	0.0%	0.5%	0.7%	0.5%	0.8%	0.9%	0.9%		
Colby Economic Outlook									
Pct. Ch. Ann. Rate		0.3%	0.7%	0.9%	0.8%				

Personal Income (Billions $)	2005	2006	2007	2008	2009	2010	2011	CAGR 2005-11	CAGR 2006-11
Global Insight	40.71	42.99	44.91	46.86	49.18	51.70	54.44	5.0%	4.8%
Pct. Ch. Ann. Rate	3.6%	5.6%	4.5%	4.3%	5.0%	5.1%	5.3%		
Consenus Economic Forecasting Commission	40.71	43.00	44.86	46.89	49.01	51.12	53.29	4.6%	4.4%
Pct. Ch. Ann. Rate	3.6%	5.6%	4.3%	4.5%	4.5%	4.3%	4.2%		
Maine State Planning Office	40.71	42.97	44.83	46.84	48.80	50.71	52.73	4.4%	4.2%
Pct. Ch. Ann. Rate	3.6%	5.5%	4.3%	4.5%	4.2%	3.9%	4.0%		
Colby Economic Outlook									
Pct. Ch. Ann. Rate		5.5%	4.2%	4.7%	5.0%				

Sources: Global Insight's Winter 2007 Economic Outlook for Maine, January 29, 2007; Report of the Consensus Economic Forecasting Commission, February 1, 2007; Maine State Planning Office Forecast, January 2007; Colby Economic Outlook, December 2006.

B. Price of Electricity and Price Elasticity

The advent of retail competition and the inherent volatility of input fuel prices for electricity production make it difficult to predict what the bundled price of electricity will be in the years ahead. Such a forecast needs to address changes in CMP's delivery price as well as the likely market supply conditions in New England. The bundled price of electricity used to prepare the Winter 2007 sales forecast is shown in Table SF-9. Between 2000 and 2004, consumers experienced a real price of electricity that was declining in most years. Then, in 2005 and 2006, supply prices jumped, significantly impacting residential sales. Modest price increases for residential customers are expected in 2007 and 2008. Thereafter, CMP projects that prices will begin to decline slightly. Over the forecast horizon, residential prices adjusted for inflation are estimated to decrease by 2.0% per annum.

Table SF-9. Estimated Price of Electricity by Class, Winter 2007 Forecast

Nominal Price of Electricity in Current Dollars

	Residential Class		Commercial Class		Other Industrial		GDP - Price Index	
	¢ per kWh	% change	¢ per kWh	% change	¢ per kWh	% change	2000=1	% change
1999	13.14		10.37		7.71		0.979	
2000	12.27	-6.6%	10.07	-2.9%	8.31	7.7%	1.000	2.2%
2001	12.12	-1.2%	11.14	10.6%	10.15	22.2%	1.024	2.4%
2002	12.35	1.9%	9.30	-16.6%	7.36	-27.5%	1.042	1.7%
2003	12.08	-2.1%	9.82	5.6%	8.29	12.7%	1.064	2.1%
2004	11.76	-2.6%	9.64	-1.9%	8.01	-3.4%	1.094	2.8%
2005	13.15	11.8%	10.49	8.8%	8.71	8.8%	1.127	3.0%
2006	14.77	12.3%	12.76	21.6%	11.59	33.0%	1.160	2.9%
2007	15.56	5.4%	13.22	3.6%	11.30	-2.5%	1.184	2.0%
2008	16.05	3.2%	12.88	-2.5%	11.09	-1.8%	1.207	1.9%
2009	15.52	-3.3%	12.38	-3.8%	10.69	-3.6%	1.231	2.0%
2010	15.18	-2.2%	12.18	-1.7%	10.55	-1.4%	1.256	2.0%
2011	14.79	-2.6%	11.61	-4.7%	9.98	-5.3%	1.283	2.1%
2006-11		**0.0%**		**-1.9%**		**-2.9%**		**2.0%**

Real Price of Electricity in Constant 2000 Dollars

	Residential Class		Commercial Class		Other Industrial	
	¢/kWh ($00)	% change	¢/kWh ($00)	% change	¢/kWh ($00)	% change
1999	13.42		10.60		7.88	
2000	12.27	-8.6%	10.07	-4.9%	8.31	5.4%
2001	11.84	-3.5%	10.88	8.0%	9.92	19.4%
2002	11.85	0.1%	8.92	-18.0%	7.06	-28.8%
2003	11.36	-4.2%	9.23	3.4%	7.79	10.4%
2004	10.75	-5.3%	8.81	-4.6%	7.32	-6.1%
2005	11.66	8.5%	9.31	5.6%	7.73	5.6%
2006	12.72	9.1%	11.00	18.2%	9.99	29.3%
2007	13.14	3.2%	11.16	1.5%	9.54	-4.5%
2008	13.30	1.2%	10.67	-4.4%	9.19	-3.7%
2009	12.61	-5.2%	10.06	-5.7%	8.69	-5.5%
2010	12.09	-4.1%	9.70	-3.6%	8.40	-3.3%
2011	11.53	-4.7%	9.05	-6.7%	7.78	-7.3%
2006-11		**-2.0%**		**-3.8%**		**-4.9%**

CMP's sales forecast uses price elasticities to translate changes in the price of electricity into positive or negative impacts on energy demand. Elasticity is a measure of response expressed in relative or percentage terms. With respect to the impact of a price change on consumption, the price elasticity is equal to the percentage change in sales divided by the percentage change in price. For example, a price elasticity of -0.2 means that a one percent increase in the price of electricity will result in a 0.2% decrease in electricity demand. CMP's price elasticities have been estimated using econometric techniques. The derived price elasticity for the residential class (-0.27) is greater than that of the commercial (-0.10) and other industrial (-0.075) classes. This means that residential customers are more responsive to price changes than commercial and industrial customers. Although residential customers respond to price changes with greater vigor than other customers, their response is delayed. That is, CMP's analysis of the residential demand for electricity suggests that there is a one year delay in responding to price changes.

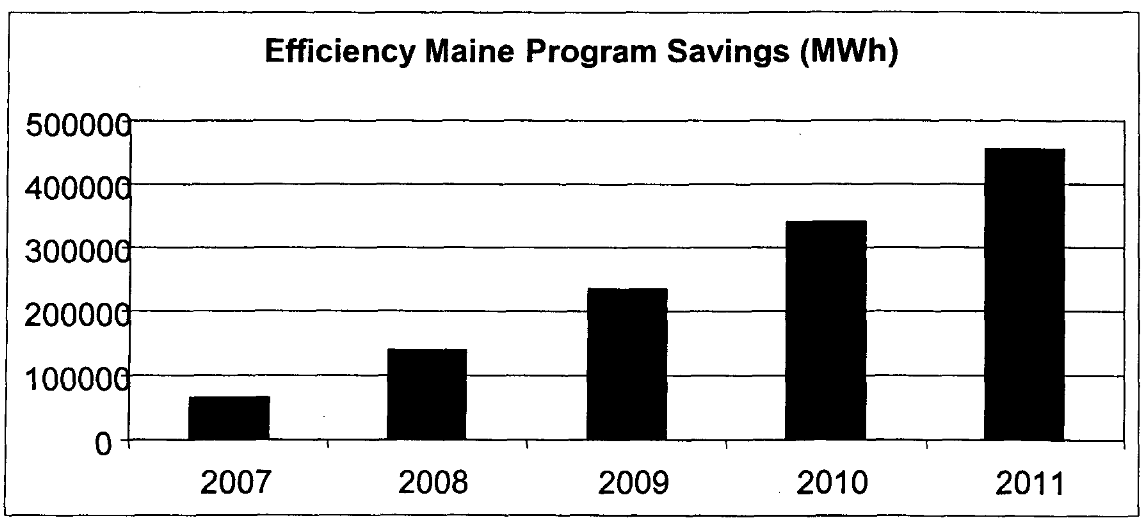
C. Energy Conservation

Efficiency Maine, a division of the Maine Public Utilities Commission, is responsible for the planning and implementation of energy conservation programs within the State. Mr. Denis Bergeron of Efficiency Maine provided CMP with its latest conservation plan during the Summer of 2006. CMP assumes that 80% of the statewide energy conservation program savings, as projected by Efficiency Maine, will occur in its service territory, and this level of energy savings is built into the CMP sales forecast. CMP's sales forecast does not incorporate any of the additional conservation savings associated with an increase in funding that was discussed in MPUC Docket No. 2006-446 and is being considered by the Maine Legislature. The forecast also does not incorporate a possible increase in Efficiency Maine funding that may be available through Maine's participation in the Regional

Greenhouse Gas Initiative and any corresponding increase in conservation savings. In addition, the sales forecast does not incorporate any of the conservation benefits expected from the company's proposed installation of advanced metering infrastructure. As discussed in Beth Nowack Cowan's testimony, the installation of AMI is expected to foster significant demand response savings by customers. For these reasons CMP's Winter 2007 sales forecast likely understates conservation results and overstates CMP sales. It is assumed that CMP's customers will contribute 1.5 mills per kWh (or about $10 million annually) to the conservation fund and that 80% of the money collected by Efficiency Maine for future energy conservation programs will be spent in the CMP service territory. Existing and currently funded conservation programs are expected to save more than 1.2 billion kWh between 2007 and 2011. The amount of expected savings by class is shown in the following Table.

Table SF-10. Estimated Conservation Savings (MWh), CMP Service Area

	Cumulative Conservation Savings, Winter 2007			
	Residential	Commercial	Industrial	Total
2007	27,819	25,074	12,537	65,431
2008	47,070	60,902	30,451	138,423
2009	67,436	111,314	55,657	234,407
2010	90,017	167,091	83,546	340,654
2011	113,791	227,415	113,708	454,914



D. Weather

As in past forecasts, the current sales projection uses the mean of the most recent 15 years of monthly data for Portland, Maine, as its proxy for normal weather. Based upon data for 1991-2005, the sales forecast assumes 7,088 heating degree days ("HDD") as its representation of normal weather for calculating heating sales. Considering both temperature and humidity, the forecast assumes 183 humidity-adjusted cooling degree days ("THICDD") as normal summer weather where THICDD is defined as (.4 * dry bulb temperature) + (.4 * dew point temperature) + 15) – 65).

In 2006, Portland experienced fewer heating degree days (6,310) than normal. A return to normal weather implies an increase in HDD sensitive load in 2007 relative to what occurred in 2006. On the other hand, the number of humidity-adjusted cooling degree days experienced in 2006 (230) was greater than normal. This implies that a return to normal weather will result in a decrease in THICDD sensitive load in 2007 relative to what occurred in 2006. On balance, a net increase in sales of about 13 million kWh in 2007 relative to 2006 is anticipated due to a return to normal weather.

III. DETAILS OF THE WINTER 2007 SALES FORECAST

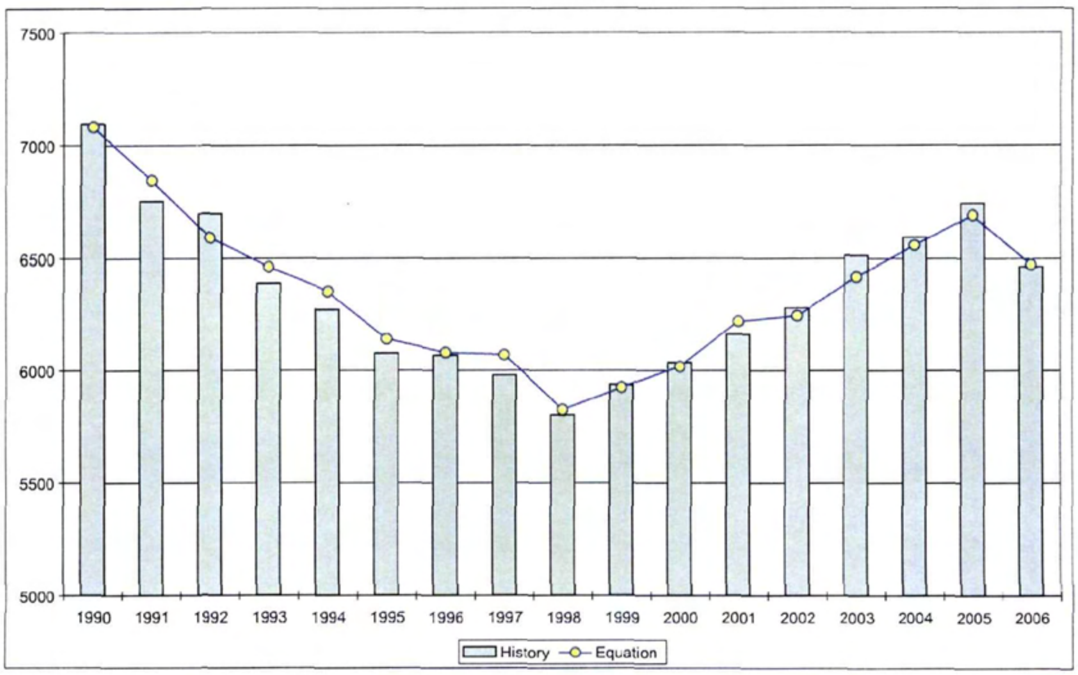
A. Residential Sales Forecast

CMP uses an econometric modeling approach to develop its residential kWh sales forecast. Two key equations are estimated. One establishes a quantitative relationship between average quarterly kWh usage per residential customer and various explanatory variables: price of electricity, income per customer, a time trend that captures growth in air conditioning, and weather conditions (heating degree days and humidity-adjusted cooling degree days). The other key equation determines new customer growth as a function of housing starts in the State of Maine.

In MPUC Docket No. 2005-729, Staff raised a concern that CMP's residential sales forecast could be low because (i) the projected rate of sales growth was less than what CMP has experienced in recent years; (ii) forecasts that CMP prepared in the past tended to underestimate sales; and (iii) an energy forecast prepared by the Energy Information Agency ("EIA") for New England projected stronger sales growth than CMP's estimate for its service territory. The OPA's consultant, Exeter Associates, did not concur with Staff's critique and suggested that CMP's sales forecast might err on the high side. Exeter, however, did express a concern with respect to CMP's use of a debt variable (the ratio of household debt to disposable personal income) in preparing its forecast.

For the Winter 2007 sales forecast, CMP has worked with Concentric to develop an explanatory equation to project average kWh use per customer to address the concerns raised in Docket No. 2005-729. The major improvements to the equation estimated by CMP are: (i) adding six additional quarters of recent data on residential kWh usage (i.e., 2005:III-2006:IV); (ii) integrating data from CMP's January 2006 saturation survey of residential customers; (iii) incorporating a variable that explicitly captures the growth that the service area has seen in residential air conditioning saturation; and (iv) dropping the debt variable as an explanatory variable.[4] Table SF-11 highlights the ability of the estimated residential equation to predict historic kWh use per customer. As shown in the Table, CMP's residential forecasting technique, which includes a variable for air conditioning, "predicts" historic usage per customer very accurately.

Table SF-11. Ability of the Residential Equation to Predict Annual kWh Usage per Customer

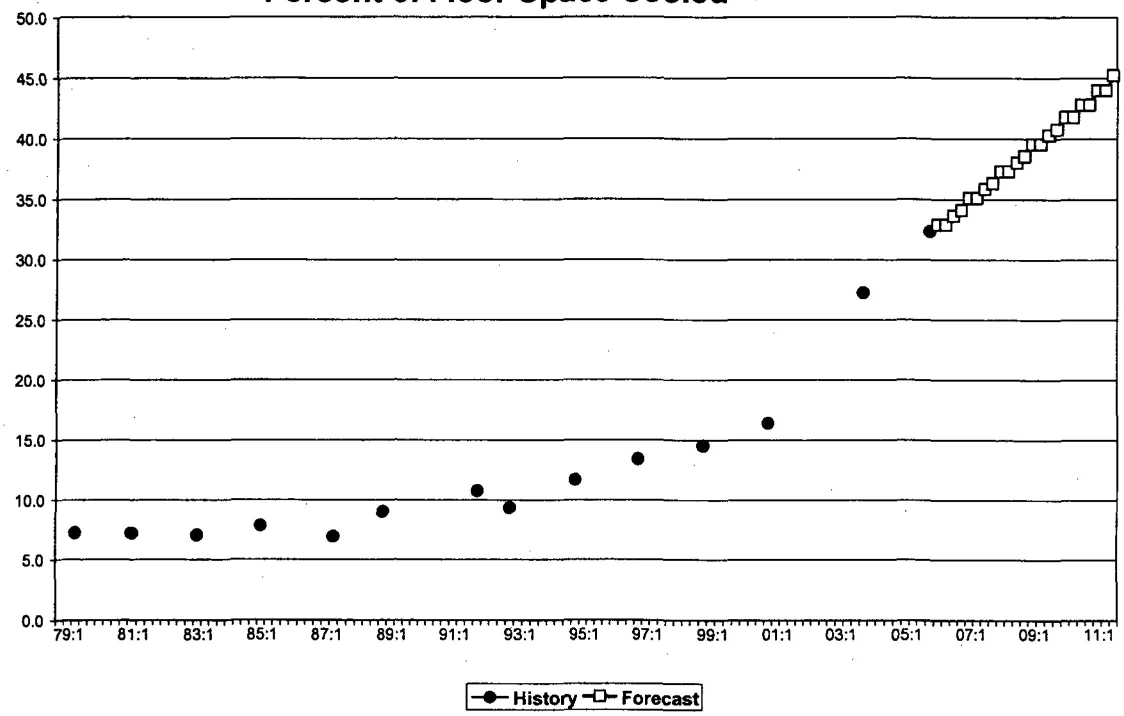


As shown in Table SF-12, CMP has experienced significant growth in air conditioning sales since 2001. CMP's 2001 survey indicated that approximately 16% of the floor space of year-round residential dwellings was air conditioned. That relationship

[4] The adoption of this equation for estimating average kWh use per customer results in a cumulative increase in residential sales of about 259 million kWh over the 2007-2011 period. That is, the average use equation put forward in Docket No. 2005-729, updated with current information, would have produced a lower forecast.

jumped to 27% in 2004 and 32% in 2006. CMP estimates that the percentage of residential floor space with cooling will approach 45% in 2011.

Table SF-12. Trend in Residential Air Conditioning, Percent of Floor Space Cooled



In addition to growth in air conditioning sales, the forecast for average kWh use per customer is positively impacted by increases in income per customer. Changes in the price of electricity have the effect of dampening usage in 2007-2009 and increasing kWh use thereafter, once the price of electricity adjusted for inflation begins to decline. Before adjustment for Efficiency Maine conservation programs, average usage per customer is projected to show modest growth, rising from 6,463 kWh in 2006 to 6,598 kWh in 2011 (or by 0.4% per annum).

Growth in the number of customers is calculated based on Global Insight's forecast for housing starts in the State of Maine. CMP forecasts that the number of customers will grow from 530,895 in 2006 to 560,356 in 2011 for an annual rate of increase of 1.1%.

Annual sales are the product of average usage per customer and the number of customers. Residential sales, before adjustment for Efficiency Maine conservation programs, are projected to rise at an annual rate of 1.5% per annum during 2006-2011. However, once conservation savings are taken into account, sales growth over the five year period is only 0.9% per annum. Efficiency Maine conservation programs will reduce residential kWh sales by a cumulative amount of nearly 350 million kWh over the forecast horizon.

CMP's residential methodology and sales forecast are discussed in greater detail in Volume III of this filing.

B. Commercial Sales Forecast

CMP uses a segment-based forecasting approach for the commercial sector. CMP prepares a sales projection for 22 different segments that correspond to various four-digit SIC codes. The segments cover the gamut of commercial activities from Agriculture to Business and Financial Services, from Construction to Restaurants and Colleges.

The Company's commercial sales forecast is actually the sum of two forecasts: one for large business customers, who account for 30% of total commercial sales, and one for the smaller customers, who account for the remaining 70% of total commercial electricity sales. In developing the sales forecast for large customers, the Company relies on interviews conducted by CMP account managers. However, in cases where a customer is unable to provide the Company with an estimate of future electricity usage, CMP uses the appropriate Global Insight output growth rate. In most cases, the information obtained from customer interviews is used to establish sales levels through

2008; thereafter, sales growth is based on Global Insight's forecast of growth in commercial output.

CMP calculates the sales outlook for smaller commercial customers by applying Global Insight's forecast of growth in commercial output to the historic sales levels of the defined business segments. Growth in output by segment is adjusted by an electricity-to-output factor that reflects relationship between growth in commercial output and growth in electricity sales. That is, historically, commercial output has grown at a faster rate than electricity sales due to the use of more energy efficient technologies. CMP has determined a commercial output elasticity of 0.912 based on the historical relationship between electricity consumption and growth in commercial output. In addition, the forecast is adjusted to reflect changes in the projected price of electricity; CMP has determined a price elasticity of -0.10 based upon observed customer behavior over the past 15 years. Finally, the total commercial sales forecast is adjusted to reflect expected savings from conservation programs sponsored by Efficiency Maine. Conservation savings are anticipated to have a significant impact on sales growth, reducing commercial sales by a total of 591 million kWh over the five-year forecast horizon.

Sales to commercial customers are expected to grow at 2.2% per year, advancing from 3,207 million kWh in 2006 to 3,567 million kWh in 2011. Before adjustment for conservation savings, the calculated commercial sales growth rate is 3.4% per annum, 2006-1011. The Global Insight economic forecast calls for commercial output, adjusted for inflation, to expand by 3.1% per year over the 2006-2011 period.

The commercial forecast methodology and sales forecast are discussed in greater detail in Volume III of this filing.

C. Industrial Sales Forecast

CMP uses a segment-based forecasting approach for the industrial sector. CMP projects sales for 19 business segments that correspond to the commonly recognized manufacturing categories (SIC Codes 20-39, excluding SIC 21 Tobacco).

The forecast for each industrial segment is the sum of the interview-based sales projections for the large customers and the output-based sales forecast for smaller customers in the sector. The forecast for large customers is developed from interviews conducted by CMP sales personnel. Large customers account for about 87% of industrial sales. In cases where a customer is unable to provide us with an estimate of future electricity usage, CMP uses the appropriate Global Insight growth rate for industrial output. In most cases, CMP relies upon the interview-based forecasts through 2008 and uses Global Insight's forecast to obtain sales estimates thereafter.

The sales outlook for the smaller industrial customers is based on Global Insight's forecast of growth in industrial output and changes in the price of electricity. A price elasticity of -0.075 has been estimated based upon the behavior of non-paper industry customers to changes in the real price of electricity over the past nine years. Growth in output by segment is adjusted by an electricity-to-output factor that reflects the relationship between growth in industrial output and growth in electricity sales. That is, historically, industrial output in a number of segments has grown at a faster rate than electricity sales due to the use of more energy efficient technologies. CMP estimated an output elasticity of 0.55 based upon electricity consumption and industrial output data for 1997-2006. Finally, CMP adjusts the total other industrial sales forecast for expected savings from energy conservation programs sponsored by Efficiency Maine.

The industrial sector forecast calls for sales to decline at an average rate of 3.8% per year during the 2006-2011 period. This is largely the result of double-digit rates of decrease in 2006 and 2007, when CMP sales to two large customers will decline significantly as each customer exercises its self-supply options.

Excluding the paper industry, electricity sales to other industrial customers are projected to experience a modest decline. Sales fall from 1,550 million kWh in 2006 to 1,496 million kWh in 2011, a -0.7% rate of decrease. Before adjustment for conservation savings associated with Efficiency Maine programs, the calculated other industrial sales growth rate is +0.7% per annum for the 2006-2011 period. Global Insight's economic forecast for industrial output, excluding the paper industry, estimates a slight decrease in real output of -0.4% per year for the 2006-2011 period.

The industrial methodology and sales forecast are discussed in greater detail in Volume III of this filing.

D. <u>Sales Outlook for Lighting</u>

Street and area lighting sales are projected to increase from 36.8 million kWh in 2006 to 38.7 million kWh in 2011. The projected rate of growth is 0.9% per annum. The street lighting forecast was developed using an exponential smoothing technique, and the area lighting forecast is based on growth in residential customers.

IV. EIA'S ANNUAL ENERGY OUTLOOK

The Energy Information Agency's Annual Energy Outlook 2007 was released in February 2007 (see http://www.eia.doe.gov/oiaf/aeo/index.html). The primary focus of the EIA's effort is to provide a long-term (2007-2030) energy outlook for the U.S. as a whole. In Docket No. 2005-729, the Staff's consultant argued that the EIA residential sales forecast for New England (associated with its Annual Energy Outlook 2006) should be used as a proxy for residential sales growth in the CMP service territory. The residential forecast based on the EIA approach presented in Docket No. 2005-729, however, overestimated actual residential sales in 2006 by 2.9%, or about 100 million kWh.

Table SF-13 compares the EIA's current outlook for New England with CMP's Winter 2007 sales forecast.[5] In short, the EIA outlook assumes that electricity prices will decline at a faster rate than CMP's forecast. Further, economic growth in the EIA forecast is stronger than what CMP expects will occur in Maine. While CMP's forecast calls for residential kWh sales to advance at 0.9% per year, 2006-2011, the EIA outlook estimates a 1.6% rate of growth.

[5] In the ISO-New England's April 2007 forecast, Maine's net energy for load is projected to grow at annual rate of 1.1% per annum, 2006-2011. However, the ISO's forecast does not incorporate the conservation savings that Efficiency Maine expects to achieve. Thus, the ISO's forecast calls for significantly slower sales growth than CMP's forecast.

Exhibit SF-13. EIA's Annual Energy Outlook 2007 for New England and CMP's Winter 2007 Forecast

	EIA Forecast for New England							CMP's Forecast		
Electricity Consumption (QBtu)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**CAGR 2006-11**	**CAGR 2006-11**	**w/o DSM 2006-11**	
Residential	0.170	0.173	0.177	0.179	0.182	0.183	1.6%	0.9%	1.5%	
Commercial	0.185	0.186	0.189	0.194	0.197	0.202	1.7%	2.2%	3.4%	
Industrial	0.081	0.081	0.081	0.081	0.081	0.082	0.3%	-0.7%	0.7%	(1)
Transportation	0.001	0.001	0.001	0.001	0.001	0.002	7.4%			
Total	0.437	0.441	0.448	0.455	0.462	0.469	1.4%	1.1%	2.1%	(1)
Electricity Prices ($2005/MBtu)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**CAGR 2006-11**	**CAGR 2006-11**		
Residential	38.68	35.24	34.55	34.50	34.48	34.04	-2.5%	-2.0%		
Commercial	35.57	31.74	30.80	29.93	29.22	27.97	-4.7%	-3.8%		
Industrial	31.75	29.72	29.06	27.26	25.49	23.42	-5.9%	-4.9%	(1)	
Transportation	33.17	30.53	30.00	29.56	29.25	28.45	-3.0%			
Total	36.07	32.73	31.96	31.26	30.64	29.55	-3.9%			
Demographics	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**CAGR 2006-11**	**CAGR 2006-11**		
Population (millions)	14.4	14.5	14.6	14.6	14.7	14.8	0.5%	0.3%		
Real Disposable Income (bil. $2000)	480.2	497.4	517.4	536.4	554.9	571.7	3.5%	2.8%		

(1) Excluding sales to the Paper Industry.

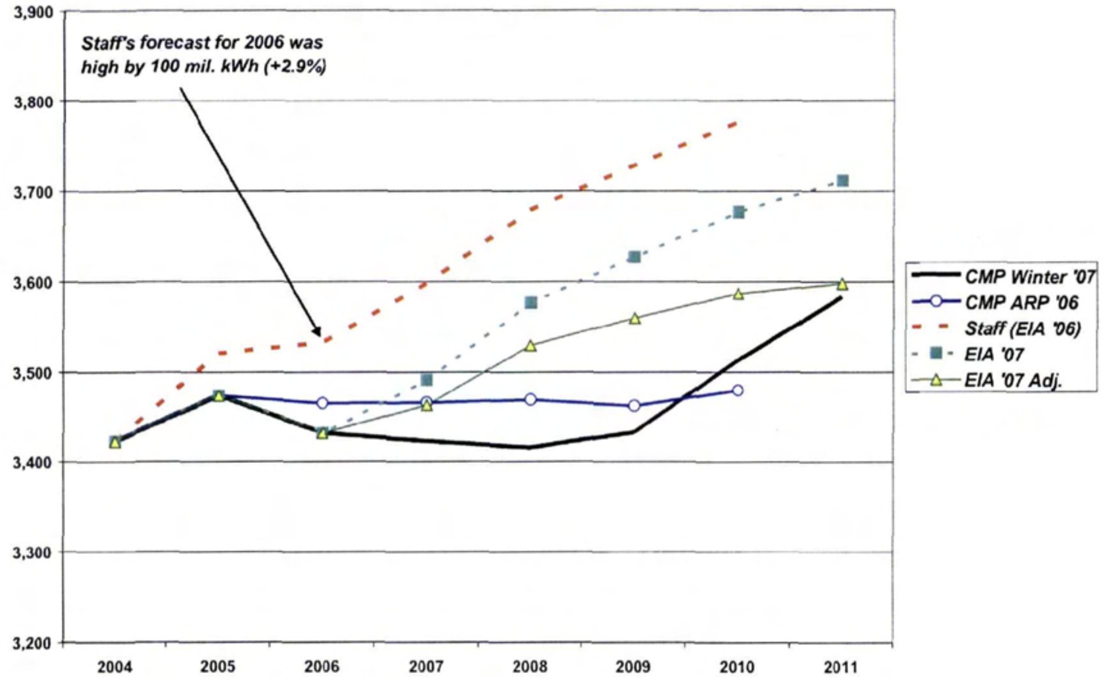
While differences in economic and price assumptions explain part of the variance in the two residential forecasts, a more significant factor is that <u>CMP's forecast explicitly incorporates the energy savings that Efficiency Maine expects to obtain while the EIA forecast does not</u>. The EIA does not even collect data on a prospective basis from utilities or state agencies, such as Efficiency Maine, on what their future conservation efforts seek to obtain in kWh savings. Thus, if one compares CMP's five-year residential growth rate before adjustment for conservation program savings with that of the EIA, the energy outlooks are comparable: 1.5% vs. 1.6%.[6]

Table SF-14 compares CMP's Winter 2007 residential sales forecast with CMP's residential sales projection offered in the 2006 ARP Extension proceeding and the Staff's

[6] While the EIA forecast may take into account some estimate of national average conservation gains, there is no reason to believe that the aggressive and successful efforts of Efficiency Maine are matched, or approached, on a nationwide basis. Moreover, the EIA methodology should be considered suspect if applied directly to Maine by virtue of its substantial error with respect to 2006 sales.

recommendation in Docket No. 2005-729. Also shown is the 2007 EIA trend forecast for New England (with and without adjustment for Efficiency Maine program savings).

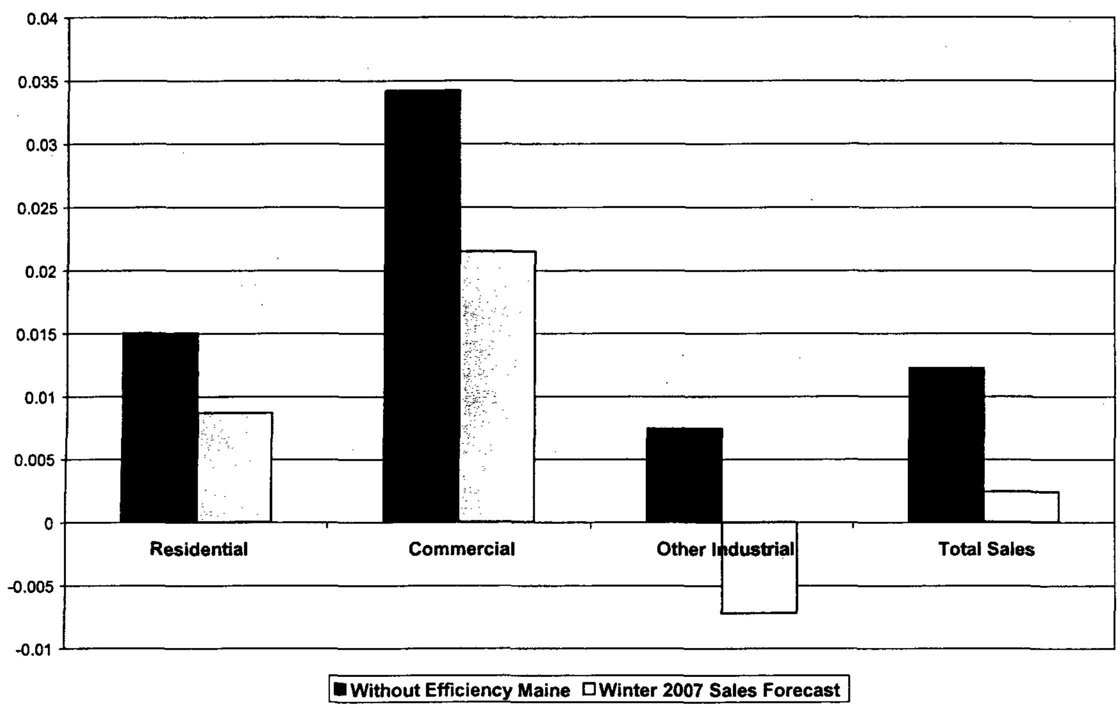
Table SF-14. Comparison of Residential Sales Forecasts (mil. kWh)



V. SUMMARY

Total electricity sales are projected to increase at an annual rate of 0.2% between 2006 and 2011. As is shown in Table SF-15, the rate of sales growth is significantly affected by the amount of conservation savings associated with Efficiency Maine programs.

Table SF-15. Impact of Efficiency Maine Programs on CMP Sales Growth,2006-2011



The Commission should accept CMP's Winter 2007 sales forecast (see Table SF-1) as the basis for determining expected distribution revenues that are used in CMP's revenue requirement and earnings review in this proceeding. The forecast is carefully tailored to Maine conditions and uses reasonable assumptions concerning economic growth and electricity usage. Moreover, as set forth in Volume IV of this filing, the forecast reflects enhancements proposed by Concentric as part of its in-depth review of CMP's forecasting methodology and resulting sales forecast. With these enhancements, which CMP has adopted, Concentric finds the Winter 2007 sales forecast to be based on sound methodologies and model inputs, consistent with industry practices in the preparation of such forecasts and a reasonable basis for the Commission's reliance in this proceeding.[7]

[7] A detailed description of CMP's forecast methodology, assumptions and results is provided in the companion Volume III of this filing. For the sake of clarity, some of the material presented in this volume is repeated there.

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Profile

John Davulis is the chief economist at Central Maine Power, an Energy East company. In this capacity, he is responsible for the preparation of CMP economic and sales forecasts. He directs staff activities related to estimating multiple regression equations and developing Excel spreadsheet models for short-term sales forecasting. He authors a monthly analysis of sales variance report and manages a variety of research projects. Mr. Davulis provides testimony before regulatory bodies on issues related to the Company's sales and peak load forecast and other economic matters.

Mr. Davulis possesses more than 30 years experience in economic modeling, short and long-term forecasting, economic analysis and program management. He joined CMP in 1986 as Principal Load Forecaster. From 1991 to 1999, he was Manager, Economic & Sales Forecasting. Mr. Davulis led the Company's effort to implement the ENERGY 2020 Model for long-range load forecasting. He also provided consulting services to the Nationalna Elektricheska Kompania of Bulgaria related to its implementation of an energy planning and policy analysis model. In 1999, Mr. Davulis accepted additional responsibilities related to managing the Company's delivery of energy conservation programs, whose cost exceeded $13 million in 2000. In 2001, he was named Chief Economist and continues in that role today.

Prior to joining CMP, Mr. Davulis was Supervisor of Load Forecasting at New England Power Planning (now part of ISO – New England). While there, he worked with other economists to develop the NEPOOL Model for long-range load forecasting, one of the first such efforts in the U.S. Earlier in his career, Mr. Davulis was a Resource Economist at the University of New Hampshire, where he co-authored a number of research papers, twice taught a course in statistical methods, and testified before the Subcommittee on Dairy and Poultry, Committee on Agriculture, U.S. House of Representatives.

Mr. Davulis holds a B.A. in Philosophy from the University of New Hampshire, a M.A. in Philosophy from the University of Cincinnati, a M.S. in Resource Economics from the University of New Hampshire, and a Graduate Certificate in International Business from the University of Maine.

Since 1987, Mr. Davulis has been a member of the NEPOOL Load Forecasting Committee and Chair, 1998-2000. Since 1993, he has served on the State of Maine's Consensus Economic Forecasting Commission. He has been a member of the Board of Directors for the Maine Energy Education Program since 1999.

<u>**Selected Publications and Presentations**</u>

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Docket No. 2001-232 Phase II, Investigation of Central Maine Power Company's Stranded Cost Revenue Requirement and Rate Design

Docket No. 97-580 Phase II, Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design

Docket No. 97-580, Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design

Docket No. 95-598, Annual DSM Targets Proceeding

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Docket No. 92-102, Application for Fuel Cost Adjustment Pursuant to Chapter 34 and Establishment of Short-Term Energy-Only Rates for Small Power Producers Less Than 1 MW Pursuant to Chapter 36 (Investigation of QF Contracts)

Docket No. 88-111, Petition for Certificate of Public Convenience and Necessity for Purchase of Generating Capacity and Energy from Hydro Quebec

Docket No. 87-268, Petition for Certificate of Public Convenience and Necessity for Purchase of Generating Capacity and Energy from Hydro-Quebec

Docket No. 87-261, Estimated 1987 Long-Term Avoided Costs Filed Pursuant to Section 3(C) of Chapter 36 of the Commission's Rules

SERC DIRECTIONS FOR ELECTRIC DISTRIBUTION COMPANY TARIFF SETTING UNDER REVENUE CAP METHOD

CHAPTER ONE

GENERAL PROVISIONS

1.1. These Directions specify the price setting for tariffs subject to regulation by the State Energy Regulatory Commission (the Commission), the type, the format and contents of the information which the Electricity Distribution Companies (the EDCs) are required to provide in a tariff application.

1.2. These directions have been developed on the grounds of Article 36, paragraph 1 of the Energy Law adopted on November 26, 2003, promulg. State Gazette No. 107 from December 9, 2003 and Article 5, paragraph 8 of the Electricity Tariff Ordinance adopted by the Council of Ministers with Decree No. 35 from February 20, 2004.

2. The basic common requirements of the Commission for the purpose of revenue cap price regulation applicable to the EDCs are defined in the Electricity Tariff Ordinance (the Ordinance) while the special requirements of the Commission are provided in this document.

3.1. These Directions contain values of basic price parameters adopted by the Commission for the first three regulatory periods.

3.2. These Directions provide for specific requirements or exceptions to the commonly applicable requirements that are valid for the first regulatory period.

3.3. These Directions provide for rules on price setting for the first year of the regulatory period and for annual adjustments during the regulatory period.

4. The regulatory periods are set as follows:

a) First regulatory period – from January 1, 2005 till December 31, 2007.

b) Follow-up regulatory periods – commencing every five (5) years after the first regulatory period.

5.1. These Directions include Attachments with specific table formats which constitute an integral part of the tariff application.

5.2. The tables include the minimum requirements of the Commission with regard to the provision of information.

5.3. The tables contain references of account numbers in the Uniform Chart of Accounts adopted by the Commission.

5.4. The EDCs may provide additional information beyond these tables, but shall not delete any rows or columns in the tables.

5.5. The Commission may require additional information while reviewing the tariff application.

6.1. Every EDC submits individual tariff application. Electricity Distribution Companies privatized in a package pursuant to the Privatization Strategy for the Electricity Distribution Companies adopted in June 2003 by the Parliament of the Republic of Bulgaria shall submit also a consolidated tariff application.

6.2. The prices of electric power and the prices for distribution are uniform throughout the territory of operation of the energy companies falling within one privatization package.

7. The initial tariff application is based on the cost of service.

8. The information provided in the initial tariff application includes test year results, revenue requirements and projected cost of service.

9. The EDCs may propose changes in their revenue requirements and cost of services for each individual licensed activity (distribution of electric power and electric power supply). Each adjustment must be detailed and justified in a written explanation with evidences provided with the tariff application.

CHAPTER TWO

REVENUE REQUIREMENTS

Section I

Basic requirements applicable to the revenue requirements

10.1. The tariff proposals for the initial rate period of the regulatory period (initial prices) are based on the annual revenue requirements for the test year with adjustments described in Section 6.

10.2. The revenue requirements are determined in accordance with Article 10 of the Ordinance and are calculated by the following formula:

$$R_{ev}R = C + (RAB \times RR_c);$$

where:

$R_{ev}R$ are the annual revenue requirements, BGN;

C the allowed annual costs of operation for the licensed activity, described in Section 5, BGN;

RAB the Regulatory Asset Base, described in Section 3, BGN;

RR_c the rate of return on capital for the regulatory period, described in Section 4, %.

Section II

Test Year Results

11.1. The test year can be either the previous calendar year or the last 12 months preceding the submission of tariff application, whichever is considered reasonable by the EDC for the pricing purposes calculations for the next regulatory period.

11.2. The EDC must prove that the test year data is representative of the costs of the company for one-year period.

12.1. The EDC must show the total revenues, expenses, assets, liabilities, other income and losses for the total company and provide a breakdown into regulated operations and non-regulated operations.

12.2. The total operating results for the test year and their allocation into regulated operations (distribution and supply) and non-regulated operations have to be presented in Table No. 1-A.

12.3. The EDC is allowed to propose adjustments to the test year data for the respective regulated operations, as well as the envisaged revenue requirements in Tables 1-B and 1-C.

13.1. Operating revenues include the revenues from the EDC's core activities – electric power distribution of electric power and public supply.

13.2. Other income may include, among other, items such as interest earned on deposits in financial institutions.

13.3. Transfer pricing is the internal allocation of distribution services by the network division provided to the retail sales division. The retail sales division includes the cost of distribution in their calculation of revenue requirements in order to calculate the cost of service for energy sales to captive consumers.

Section III

Regulatory Asset Base

14.1. The regulatory asset base (RAB) is determined pursuant to Article 14 of the Ordinance and is calculated according to the following formula:

$$RAB = A - CG - D + WC + INV_{av};$$

where:

RAB the Regulatory Asset Base, BGN;

A the allowed value of used and useful assets, BGN;

CG the value of assets acquired through gratuitous transfer or constructed with financial resources of electricity consumers, BGN;

D the accumulated depreciation for the past period of asset use to perform the licensed activity, BGN;

WC the working capital allowance, BGN;

INV_{av} the forecast average cumulative nominal amount of the net investments approved by the Commission, which will be invested during the regulatory period, BGN.

14.2. The EDC provides information about the test year level of regulatory asset base, the proposed adjustments to the regulatory asset base and the projected regulatory asset base for the next regulatory period in Table No. 2-A as a summary, and in Tables 2-B and 2-C respectively by distribution operations and supply operations.

14.3. The Work In Progress item in Tables 2 includes the value of assets to be commissioned not later than then end of the year which precedes the beginning of the regulatory period.

14.4. The forecast average cumulative nominal amount of the net investments which will be invested during the regulatory period is calculated according to the following formula:

$$INV_{av} = \frac{(INV_{t_1} * n + INV_{t_2} * (n-1) + ... + INV_{t_n} * 1)}{n};$$

where:

INV_t envisaged net investments in the year t, BGN;

t sequential year of the regulatory period;

n total number of years in the regulatory period.

14.5. The net investments for every year are equal to the difference between the Investment Plan and the Assets Decommissioning Plan.

14.6. The value of tangible fixed assets in the RAB for the first regulatory period equals the book value of tangible fixed assets by the end of 2003 before revaluation times a factor equal to 2. The value of intangible assets equals the book value as of end 2003, before revaluation.

15. The EDC provides the results of any revaluation of fixed assets which was performed in accordance with the Bulgarian Accountancy Act and the International Accounting Standards and which was completed after the last tariff application. The EDC provides a breakdown of assets, by categories included in the regulatory asset base, before and after the revaluation. Table No. 2-D provides a template for reporting a revaluation of assets relating to the regulatory asset base.

16.1. The regulatory asset base for a separately priced licensed service includes only those assets that support the licensed service. Assets that do not support the licensed service will be disallowed from the regulatory asset base. Examples of disallowed assets include all assets used for non-licensed activities, recreational facilities and assets purchased by the energy company above their market value. Table No. 2-E provides a template for adjusting the asset base for disallowed assets.

16.2. The EDC does not earn return on capital grants, i.e. on the value of assets acquired through gratuitous transfer (grants) or on assets constructed with financial resources of electricity consumers (connection of consumers). Depreciation of these assets is included in the revenue requirements.

17.1. Prudent investment programs, as part of the Business Plan, approved by the Commission are included in the regulatory asset base. Table No. 2-G provides a template for a summary of the investment program. The EDC provides the Commission with written analysis and testimony on the breakdown of the proposed investment program for the regulatory period, providing detailed justification on the results of each major investment in terms of efficiency improvements and/or improvements in the service and energy quality performance.

17.2. The regulatory asset base does not include assets which will be decommissioned during the respective year of the next regulatory period. Table No. 2-H shows a template of Assets Decommissioning Plan on yearly basis.

18. The EDC provides a summary of all investments made during the previous regulatory period and written testimony of the results of these investments. Table No. 2-G provides a template for the purposes of reporting the previous regulatory period investment program. The summary of results must show efficiency improvements and/or improvements in energy and service quality performance.

19.1. The EDC provides information on the accumulated depreciation for all assets in the regulatory asset base as of the end of the current regulatory period, along with depreciation of work in progress and depreciation of investments for the next regulatory period, in summary and by operations as shown in Tables No. 4-A, 4-B and 4-C.

19.2. The average cumulative depreciation amount for investments in Tables 4 is calculated according to the following formula:

$$D_{av} = \frac{(D_{t_1} * n + D_{t_2} * (n-1) + ... + D_{t_n} * 1)}{n};$$

where:

D_t depreciation in the year t, BGN;

t sequential year of the regulatory period;

n total number of years in the regulatory period.

19.3. Depreciation of assets is based on the most recent deprecation study made by the EDC, that shows the expected useful life of the assets by category.

19.4. The energy company should propose depreciation of the non-tangible assets.

19.5. Depreciation is calculated with a linear method depending on the assets’ useful life.

19.6. The level of depreciation for the first regulatory period equals the book value of depreciation by the end of 2003 before revaluation times a factor equal to 2.

20.1. The working capital allowance in the regulatory rate base will reflect on a study of the funds required to maintain a suitable level of receivables, material and supplies and the cash required to meet current obligations, as well as payables. Any such study has to be included in the tariff application. In the absence of such study, the EDC will provide an estimate of the working capital allowance with written evidence justifying such an estimate. The final working capital allowance included in the rates will be determined by the Commission. Table No. 2 provides a summary table of the working capital allowance.

20.2. The level of working capital for the first regulatory period equals 1/8 (one eighth) of the Distribution Company's revenue requirements before inclusion of working capital.

21. Tables No. 1-A, 1-B and 1-C provide for a summary table of the RAB and tables of the RAB by licensed services. The proposed RAB must include the proposed investments that will become commercial during the regulatory period as well as the expected level of depreciation expense for all assets included in the forecasted RAB.

Section IV

Return on Regulatory Asset Base

22.1. The Commission will determine the appropriate Return on Equity for the EDC which will be the rate for a riskless security in Bulgaria plus a risk premium related to the risk inherent in an EDC.

22.2. The Commission has initially set the pre-tax rate of return on equity at 16% for the first regulatory period.

22.3. In the future regulatory periods, the Commission will use the Capital Asset Pricing Model or another methodology, where the Commission will use a number of factors for consideration, including: (1) comparisons with other companies with similar risk levels; (2) the attraction of capital; (3) current financial and economic conditions in the country; (4) the cost of capital; (5) the risk of the company; (6) the financial policy and capital structure of the company; (7) the competence of management team; (8) the company's financial history.

23.1. The Commission determines the normalized (market-oriented) Cost of Debt. The calculation is based on interest rates for outstanding debt of the EDC. The interest rates used for determining revenue requirements may or may not be the same as actual interest rates for debt. The EDC must show that the interest rates for debt are within the same range as the interest rates for debt assumed by other companies with similar credit risks. Any debt included in the calculation of average debt interest rate that has an interest rate higher than the current market level will be adjusted downward to the market level.

23.2. The Commission sets the cost of debt as equal to the actual cost of debt for the first regulatory period

24.1. The Commission requires a long-term target capital structure of 50% equity and 50% debt for all EDC. The Commission will expect that each EDC will start using this capital structure starting in the third regulatory period.

24.2. For the first regulatory period the capital structure is the existing capital structure as on June 30, 2004.

24.3. For the second and third regulatory periods the Commission uses the most recent annual balance sheets reflecting the equity to debt ratio plus the expected investment level during the regulatory period to determine the appropriate capital structure.

24.4. The Commission assumes that the EDCs will use 100% debt for all new required investments.

25.1. The Commission approves rate of return on capital (a weighted average cost of capital). The EDC will propose a rate of return on capital for the regulatory period with an appropriate capital structure, rate of return on equity and on debt. The rate of return on capital is estimated on a pre-tax basis from the following formula:

$$RR = C_{EP} \times \left(\frac{RR_{EQ}}{1 - \frac{CPTR}{100}} \right) + C_{DP} \times RR_D$$

where:

- RR is the rate of return on capital, before taxation, %;
- C_{EP} the equity portion of capital, %;
- RR_{EQ} the rate of return on equity, after taxation, %;
- CPTR the corporate profit tax rate in compliance with the Corporate Income Tax Act, %;
- C_{DP} the debt portion of capital, %;
- RR_D is the rate of return on debt, %.

25.2. The form of the proposed long-term debt is shown in Table No. 5-A.

25.3. The form of the proposed weighted average cost of capital is shown in Table No. 5-B.

25.4. For the second and third regulatory periods the weighted average cost of capital shall not be less than 12%.

Section V

Operating Expenses

26.1. The groups of expenses for regulatory purposes and their analytical levels are defined in a Uniform System of Accounts adopted by the Commission.

26.2. The EDC provides a summary of the expenses by types of operations and grouped by cost centers. Tables No. 6-A, 6-B and 6-C provide the minimum list of expenses that need to be provided as separate cost items.

26.3. The EDCs provide breakdowns of costs in a manner which enables identification of each cost for pricing purposes. EDCs are allowed to present detailed breakdowns of costs, if such are needed to justify the proposed prices or if requested by the Commission.

27. The EDC must provide to the Commission test year results on a monthly basis for the following items:

a) power purchases, retail sales and technological costs (energy losses) for distribution in BGN, as shown in Table No. 3-A;

b) power purchases, retail sales and technological costs (energy losses) for distribution in MWh, as shown in Table No. 3- B;

c) historical and forecast number of consumers, as shown in Table No. 3-C;

d) historical and forecast peak loads, as shown in Table No. 3-D.

28. The Commission assumes technological costs (energy losses) for distribution by regulatory periods, as follows:

28.1. For the first regulatory period the losses for distribution are equal to those included in retail rates in force as from July 1, 2003;

28.2. For the second regulatory period the allowed losses for distribution are equal to the lower of the two: allowed losses for the first regulatory period minus 3% or actual total losses of the EDC for 2006;

28.3. For the third regulatory period the allowed losses for distribution are equal to the average of the allowed losses for the second regulatory period and 12%;

28.4. For all regulatory periods after the third one the allowed losses for distribution shall be based upon an investment programme for further reduction of losses negotiated between the EDC and the Commission.

Section VI

Adjustments to Test Year Results

29.1. The EDC is allowed to propose changes to the test year expense results for setting tariffs for the next regulatory period. Any such changes must be both known (a specific item) and measurable (quantifiable) – described by types of costs and in numerical values. The Commission may consider adjustments to test year results for items such as:

a) demand growth or decreases;

b) inflation;

c) contract price changes;

d) changes in taxes and insurance;

e) the number of customers served;

f) changed levels of the regulatory asset base;

g) cost of capital;

h) level of depreciation expense;

i) efficiency improvement factor.

29.2. The annual revenue requirements may be adjusted by a factor which reflects the uncollectible revenues, provided that the EDC presents evidence on the reasons for their occurrence. The adjustment to the revenue requirements for the first regulatory period is the lower value of either 3% of the RR or the actual level of uncollectible revenues. The EDC must supply a plan for reduction of uncollectible revenues. For the next regulatory periods the initial maximum 3% adjustment factor will be reduced based upon benchmarking studies of the best practices in the region.

30. The EDC must provide justification for each proposed adjustment to the test year results. The adjustments must be specified in the tables attached to the tariff application and be supplied with written testimony providing evidence of the reason(s) for each adjustment and the amount for each adjustment.

CHAPTER THREE

COST OF SERVICE

Section I

Allocation of costs by licensed operations and services

31. The EDCs should propose and provide to the Commission an allocation of the revenue requirements for first year of the regulatory period between the license types and the separately priced services to be provided within the license types.

32. The EDCs should propose allocation factors for all components of the revenue requirements between the two license types – Distribution Network Development & Operation and Retail Sales. Table No. 6 provides an example of the resulting allocation. The EDCs should provide not only the allocation factors, but also the basis and justification for the different allocation factors chosen, such as: number of employees, number of customers, level of energy sales, peak loads. Some revenue requirement components may only be directly related to one license type and therefore all such components should be completely allocated to that license type.

33.1. EDCs should propose services for which separate pricing will be applied within the respective licensed operations. EDCs should propose separately priced services for the beginning of the second regulatory period.

33.2. The services provided under distribution network operation include, without being limited to:

a) Distribution of electric power;

b) Disconnection/reconnection of consumers;

c) Connection of new consumers and producers.

33.3. The services provided under retail sales operation include, without being limited to:

a) Energy sales to captive consumers;

b) Meter reading, billing and collection of revenues.

34.1. The EDCs should propose allocation factors for all components of revenue requirements for the license types between the various services. The EDCs should provide not only the allocation factors, but also the basis and justification for the different allocation factors chosen, such as number of employees, number of customers, level of energy sales, peak loads. Some revenue requirement components may only be directly related to one service and therefore all such components should be completely allocated to that service.

34.2. The EDC provides the results of its cost of service study divided into its distribution services and its retail supply services in the format shown in Table No. 7-A.

35. EDCs classify and separate their costs into fixed costs and variable costs. Fixed costs are those that do not change with the volume of energy transferred or sold. Variable costs are those that change with the volume of energy transferred or sold.

Section II

Allocation of costs by rate groups

36.1. In its tariff application the EDC is allowed to propose rate groups for each separately priced service.

36.2. For the first regulatory period the Commission assumes the existing rate groups for the individual services. The companies will be allowed to propose another rate group classification at anytime during the first regulatory period.

37.1. The EDC provides the results of its cost of service study for its distribution services, by rate groups in a format shown in Table No. 7-B.

37.2. The EDC provides the results of its cost of service study for its retail supply services and the costs allocated to each of the retail rate groups in a format shown in Table No. 7-C.

CHAPTER FOUR

RATE DESIGN

Section I

Initial Rate Design

38. The initial rate design for the first year of the first regulatory period is based on the rate design existing by July 2004, where the existing rate design includes the following basic groups of prices: retail tariffs for consumers by voltage levels and distribution wheeling tariffs.

39.1. The retail tariffs for consumers serviced by the EDCs within one privatization package are changed based on the change of the sum of the approved revenues for the EDCs within one package for the first regulatory period, as compared to their approved revenues by July 2004.

39.2. The specific change of rates is determined observing the requirement to equalize the average sale prices for consumers at low voltage.

39.3. The rates need to be changed so that they enable recovery of approved revenue requirements for the first year of the first regulatory period.

40.1. The distribution wheeling tariffs are calculated by voltage levels – medium voltage and low voltage. Eligible consumers are charged the appropriate distribution wheeling charge based on their connection voltage level.

40.2. The distribution wheeling charge at medium voltage is calculated according to the following formula:

$$P_{D\,MV} = \frac{C_{D\,MV}}{E_{total}};$$

where:

$P_{D.MV}$	price for distribution at medium voltage, BGN/kWh;
$C_{D.MV}$	fixed costs (return included) and variable costs of the EDC for electric power distribution operations through HV and MV networks, BGN;
E_{total}	forecast demand by consumers at MV and LV, kWh.

40.3. The distribution wheeling charge at low voltage is calculated according to the following formula:

$$P_{D\,LV} = \frac{(C_{D\,TOTAL} - R_{D\,MV})}{E_{LV}};$$

where:

$P_{D.LV}$	price for distribution at low voltage, BGN/kWh;

$C_{D.TOTAL}$ fixed costs (return included) and variable costs of the EDC for electric power distribution operations through HV, MV and LV networks, BGN;

$R_{D.MV}$ revenues from consumers for electric power through HV and MV network for the distribution service, BGN;

E_{LV} forecast sales to LV consumers, kWh.

40.4. The costs for wheeling are included in the retail tariffs for the captive consumers.

40.5. The distribution wheeling rates are one-part tariffs until the EDC files for a new tariff application providing justification for a multi-part tariff.

Section II

Future Rate Design

41.1. The EDC may file an application to revise the rate structure within the first regulatory period if the EDC provides a rate design study based on customer usage patterns and cost of service for the various retail electricity rate groups.

41.2. For future rate periods the EDC may propose a revised rate design for approval by the Commission. The revised rate design will be used to calculate the annual revenue requirements for the test year for each rate group and must be presented in a format similar to the one in Table No. 8. This table shows, for each rate group, the revenues for the test year with the current tariffs and with the proposed tariffs, and also indicates the percentage change.

41.3. The results obtained using the initial rate design which are presented in Table No. 9 must indicate the return on rate base, as calculated from the cost of service study for each rate group.

Section III

Equalizing the Rate of Return and Finalizing Rate Design

42. The rate of return on rate base shown on Table No. 9 should, insofar as it is possible, be made equal and levelized for each rate group. This may be accomplished by adjusting the proposed rate designs for each rate group. The EDC may propose and the Commission may allow for adjustments according to mitigating circumstances for a particular rate group.

CHAPTER FIVE

ANNUAL ADJUSTMENTS DURING THE REGULATORY PERIOD

43. Within the regulatory period the EDC's revenue requirements will be adjusted annually as described below. All other changes in the revenue requirements will be made at the next regulatory review and will be reflected in the EDC's revenue requirements for the next regulatory period.

44.1. The annual adjustment to the revenue requirements for the first regulatory period is calculated according to the following formula:

$$\mathrm{Re}\,vR_t = \mathrm{Re}\,vR_{(t-1)} + O\,\&\,M \times \; I + Z - Y\;;$$

where:

RevR annual revenue requirements of the EDC, BGN;

O&M operation and maintenance costs, BGN;

I inflation for a 12-month period preceding the submission of application;

t rate period;

Z adjustment for differences between forecast and actual power purchase costs for the previous year, BGN;

Y service and energy quality adjustment for the previous year performance, BGN.

44.2. The annual adjustment to the revenue requirements for the second regulatory period and all future regulatory periods is calculated according to the following formula:

$$\mathrm{Re}\,vR_t = \mathrm{Re}\,vR_{(t-1)} \times (1 + I - X) + Z - Y\;;$$

where:

RevR annual revenue requirements of the EDC, BGN;

I inflation for a 12-month period preceding the submission of application;

t rate period;

X efficiency improvement factor;

Z adjustment for differences between forecast and actual power purchase costs for the previous year, BGN;

Y service and energy quality adjustment for the previous year performance, BGN.

44.3. The inflation factor representing the inflation for a 12-month period preceding the submission of application (I) is the official inflation rate that is published by the National Institute of Statistics.

44.4. The efficiency improvement factor (X) is calculated on the basis of improved efficiency achieved by the EDC during the previous regulatory period and based upon benchmarking studies for other EDC in Bulgaria and in the region.

44.5. The adjustment for differences between forecast and actual power purchase costs for the previous year (Z factor) represents un-anticipated and uncontrollable purchase power costs that have been incurred by the EDC to provide continued service for the consumers.

44.6. The service and energy quality adjustment for the previous year performance (Y factor) reflects the calculation of target versus actual energy and service performance indicators in accordance with the license conditions.

45.1. The annual adjustments for differences in forecast and actual cost of purchased power for the previous year (Z) will be calculated according to the following formula:

$$Z_t = (E_{sale}^{forecast} * P_{sale}^{forecast} - E_{purchase}^{forecast} * P_{purchase}^{forecast}) - (E_{sale}^{actual} * P_{sale}^{actual} - \frac{E_{sale}^{actual}}{1 - TC_{distr}} * P_{purchase}^{actual})_{t-1} \pm C_{pr\ per\ (t-2)}$$

,

where:

$E_{sale}^{forecast}$	forecast electric power sales, kWh;
$P_{sale}^{forecast}$	forecast average sale price of electric power, BGN/kWh;
$E_{purchase}^{forecast}$	forecast electric power purchases, kWh;
$P_{purchase}^{forecast}$	forecast average purchase price of electric power, BGN/kWh;
E_{sale}^{actual}	actual electric power sales, kWh;
P_{sale}^{actual}	actual average sale price of electric power, BGN/kWh;
TC_{distr}	approved technological costs for distribution for the regulatory period, %;
$P_{purchase}^{actual}$	actual average purchase price of electric power, BGN/kWh;
$C_{pr\ per\ (t-2)}$	adjustment for under- or over-recovered expenses for purchase of electric power in the year preceding the current adjustment, BGN;
t	rate period.

45.2. The actual electric power sales include the sales reported for the months starting from the beginning of the year till the end of the month which precedes the submission of adjustments proposal, and a forecast sales till the year end.

45.3. The actual average electric power sale price includes the reported average sale price for the months starting from the beginning of the year till the end of the month which precedes the submission of adjustments proposal, and a forecast average sale price till the year end.

45.4. The adjustment for under- or over-recovered expenses for purchase of electric power in the year preceding the current adjustment (year t-2), reflects the difference between forecast and actual quantities and prices for the period between submission of the previous adjustments proposal and the end of the previous year (year t-1). This adjustment will be applied starting from the third year of the first regulatory period. The adjustment will be applied for each year of the following regulatory periods.

46.1. The EDC's revenue requirements for the next year will be reduced in case of non-performance of the EDC in meeting its service and energy quality targets for the previous year. These performance indicators are specified in the license conditions for distribution services and retail supply.

46.2. The performance indicators for the energy companies reflecting achievement of preset targets are as follows:

a) Indicators for the quality of delivered electric power;

b) Continuity of supply indicators;

c) Written response time to a written complaint from a consumer;

d) Time to check, and if necessary –replace, a commercial meter upon customer request;

e) Time to correct meter reading errors;

f) Time to correct errors in bills for consumed electric power;

46.3. The indicators under paragraph 46.2., а) and б) above are set for each regulatory period with a decision of the Commission, depending on the available statistical information.

46.4. The application of energy and service quality indicators will not start before January 1, 2006.

47.1. The Commission sets maximum negative adjustment to the revenue requirements in BGN for each individual indicator. The maximum adjustment amount is linked to the return the EDC is expected to earn on investments made during the regulatory period to improve the performance.

47.2. The Commission sets annually a target range for each indicator. The EDC must meet or exceed the lower limit of the range in order not to incur a decrease in the revenue requirements for the following year. The higher limit of the range (upper threshold) is the value for which the maximum penalty will be applied.

47.3. The maximum negative adjustment is multiplied by a factor reflecting the ratio of the differences between 1) the actual performance and the target level and 2) the upper threshold and the target level.

47.4. Adjustment is not applied whenever the actual performance level is equal or less than the target.

47.5. Whenever the actual performance level exceeds the target, the adjustment is either of the following two, whichever is lower: 1) the maximum negative adjustment, or 2) the maximum negative adjustment times the adjustment factor.

47.6. Calculation of the adjustment for performance is made according to the following formula:

$$APQI = A_{\max} * \frac{AP - T\arg et}{UT - T\arg et};$$

where:

APQI	adjustment to the revenue requirements for performance of quality indicators, BGN;
A_{max}	maximum adjustment to the revenue requirements, BGN;
Target	target value for the given indicator;
AP	actual performance for the indicator;
UT	maximum upper level of the indicator for which applies the preset maximum penalty (upper threshold).