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CENTRAL MAINE POWER COMPANY
REQUEST FOR NEW ALTERNATIVE RATE PLAN
("ARP 2014")

SUPPLEMENTAL PRODUCTIVITY OFFSET FACTOR

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1. INTRODUCTION AND SUMMARY

Central Maine Power Company (the "Company" or "CMP") is proposing a new alternative rate plan ("ARP") for its power distribution services. The attrition relief mechanism ("ARM") of the ARP is a key issue in its design. Faced with slow volume growth in a period of mounting investment needs, the Company is proposing that the ARP feature revenue decoupling.

In its initial filing, the Company also proposed an ARM with a "hybrid" design. The budget for operation and maintenance ("O&M") expenses would be escalated each year by an index based on industry input price and productivity research. The budget for capital cost would have a predetermined stairstep trajectory based on a Company cost forecast.

This general approach to ARM design was rejected by the Maine Public Utilities Commission ("MPUC" or "Commission"). The commissioners, in their deliberation on the issue, stressed that a workable approach to supplemental compensation for high capital expenditures ("capex") should limit the role of forecasting and preserve strong performance incentives. The Company is now proposing that budgets for most of its capital cost as well as its O&M be escalated by a single index-based ARM. This ARM provides some supplemental revenue that would help fund investments but preserves strong incentives because it is based on the productivity trends of other utilities.

1.1 Qualifications of Witness

This report was prepared by Dr. Mark Newton Lowry of Pacific Economics Group ("PEG") Research LLC, an economic consulting firm that is prominent in the field of ARP design. Research on revenue decoupling and empirical issues, such as input price and productivity trends of utilities, which are salient in ARM design are Company specialties. The team he leads has over 60 man-years of experience in the field of statistical utility cost research. CMP has retained PEG Research to prepare a study on the price and productivity trends of Northeast power distributors to support the development of an ARM for the proposed new ARP.

Dr. Lowry is the President of PEG Research. In that capacity, he has for many years supervised statistical research on input price and productivity trends of electricity and natural gas utilities. He has testified or filed commentary on industry productivity trends and other ARP design issues more than twenty five times, including three previous occasions in Maine. He has also testified several times on revenue decoupling. Other venues for his testimony have included Alberta, British Columbia, California, Colorado, the District of Columbia, Hawaii, Illinois, Kentucky, Georgia, Maryland, Massachusetts, New Jersey, Oklahoma, Ontario, Oregon, New York, Quebec, Vermont, and Washington. His practice is international in scope and has also included projects in Australia, Europe, Japan, and Latin America. Work for diverse clients has given him a reputation for objectivity and dedication to regulatory science.

Before joining PEG, Dr. Lowry worked for many years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of Regulatory Strategy. The key members of his group have joined him at PEG. Dr. Lowry's career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and statistical methods in industry analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances. He holds a doctoral degree in applied economics from the University of Wisconsin-Madison.

1.2 Revenue Cap Design

ARPs with revenue decoupling require an ARM to escalate rates between rate cases. Most commonly, the ARM escalates allowed revenue. Input price and productivity research is useful in ARM design. The key drivers of utility cost are input prices, productivity, and operating scale. A sensible index-based formula for allowed revenue escalation is:

$$growth\ Revenue = Inflation - X + growth\ Customers.$$

The X factor and customer growth terms can be consolidated, producing a lower "consolidated" X factor that produces the same result.

$$\begin{aligned} growth\ Revenue &= Inflation - (X - growth\ Customers) \\ &= Inflation - X^{Consolidated} \end{aligned}$$

1.3 Empirical Findings

In the empirical research for CMP, multifactor input price and productivity indexes have been calculated for two samples of northeast power distributors for which good data are available. The growth trends of these indexes were then compared to those of analogous indexes for the U.S. economy. Established methods and publicly available data from respected sources were used in developing the indexes.

The 2002-2011 sample period and the groups of sampled utilities were carefully chosen. The end date of the sample period is the latest for which the data used to construct the utility indexes are as yet available. The year 2002 is a good start date because it provides a ten year period in which the effects of industry restructuring on the general cost of utilities were quite limited. Two Northeast regions were considered in our research. The first, which we will call the "upper" Northeast, was defined as upper New York State and New England. This region has been used in previous indexing studies prepared for ARP proceedings in Maine and has been favored by Bench Staff. The second Northeast region considered, which we will call the "broad" Northeast, adds utilities in the mid-Atlantic region.

The multifactor productivity ("MFP") of the sampled upper Northeast power distributors was found to average **0.56%** growth per annum. During the same period, the federal government's MFP index for the U.S. private business sector averaged **1.11%** annual growth. The productivity differential was thus **-0.55%.**

The trend in the multifactor input price index for the sampled power distributors averaged 3.55% growth per annum. The corresponding trend in an input price index for the U.S. economy was estimated to be about **3.20%**. The resultant input price differential of about **-0.35%** suggests that the input price growth facing Northeast power distributors was very similar to and a little more rapid than that facing the typical firm in our economy.

The MFP of the sampled broad Northeast power distributors was found to average **1.06%** growth per annum. The productivity differential was thus **-0.05%.** The trend in the multifactor input price index for the broad Northeast power distributors averaged **3.44%** growth per annum. The resultant input price differential was **-0.24%**.

CMP increased its capital expenditures ("capex") considerably in 2011 and expects capex to remain at higher levels during the years of the proposed ARP. PEG has undertaken statistical research to compute an adjustment to the X factor appropriate for a typical northeast utility in need of high capex. The resultant K factor would not weaken CMP's performance incentives or require a review of its cost forecasts. Our research suggests a K factor that would reduce X by 63 basis points for the upper Northeast and by 36 basis points for the broad Northeast.

The stretch factor component of an X factor is designed to facilitate the sharing of the benefits of performance improvements that may be encouraged by the plan's strong incentives. The need for sharing depends in part on the Company's operating efficiency at the start of the plan. CMP experienced superior MFP growth during the sample period. This should have brought it to a level of performance that is at the very least average for the industry, and possibly better.

The need for sharing depends as well on whether the proposed ARP is expected to generate stronger performance incentives than those under which the sampled distributors operated. The proposed ARP has a five year term but also contains a provision to share surplus earnings. Meanwhile, the average interval between rate cases of the sampled power distributors was about 4.8 years for the upper Northeast utilities and 5.9 years for the broad Northeast utilities. Earnings sharing mechanisms were uncommon in the broad Northeast. These considerations suggest that the stretch factor for CMP should be 0.00%.

To summarize, the research using data for the upper Northeast region that is preferred by Bench Staff suggests a consolidated X factor of **-1.90%**. This is the sum of a **-0.55%** productivity differential, a **-0.35%** input price differential, a **-0.63%** K factor, a **0.00%** stretch factor, and **-0.37%** forecasted customer growth. The research using broad Northeast data suggests an X factor of **-1.02%** for CMP. This is the sum of a **-0.05%** productivity differential, a **-0.24%** input price differential, a **-0.36%** K factor, a 0.00% stretch factor, and a **-0.37%** offset for forecasted customer growth.

2. ARM Design

ARPs are the most common approach to utility regulation around the world today. In such plans, a moratorium is typically placed on general rate cases for several years. An ARM usually adjusts allowed rates or revenues automatically for changing business conditions between rate cases. These mechanisms are designed before the start of the plan and are external in the sense that they are insensitive to the costs of the utility during the plan period.

The ARM is one of the most important components of an ARP. Such mechanisms can substitute for rate cases as a means to adjust utility rates for trends in input prices, operating scale, and other external business conditions that affect utility earnings. As such, they make it possible to extend the period between rate cases and strengthen utility performance incentives. The mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers.

ARMs can escalate rates or allowed revenue. Price caps have been widely used to regulate industries, such as telecommunications, for which it is important to promote marketing flexibility while protecting core customers from cross-subsidization. Under traditional rate designs, which involve high usage charges, price caps make utility earnings sensitive to system use. Since cost is insensitive to use in the short and medium term, utilities are incented to encourage greater use. A price cap approach made sense for CMP when it was vertically integrated because it afforded the Company more flexibility in marketing to the price-sensitive industrial sector, which included many paper mills.

Under revenue caps, the focus of escalator design is the growth in the allowed revenue needed to afford compensation for growing cost. Allowed revenue is sometimes called the target revenue, revenue requirement, or "budget". The allowed revenue yielded by a revenue cap escalator in a given year must be converted into rates, and this conversion depends on billing determinants.

Revenue caps are often paired with a revenue decoupling mechanism that removes the utility's disincentive to promote efficient energy use. However, revenue caps have intuitive appeal with or without decoupling since revenue cap escalators deal with the drivers of *cost* growth, whereas price cap escalators must consider the more complicated issue of the *difference* between cost and billing determinant growth. As a consequence, revenue caps are sometimes used even in the absence of decoupling. Current examples of companies operating under revenue caps without decoupling include Green Mountain Power in Vermont and two gas utilities in Alberta.

2.1 Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design ARMs for revenue decoupling plans. To understand the logic it is helpful to first have a high level understanding of input price and productivity indexes.

2.1.1 Input Price and Quantity Indexes

The growth trend in a company's cost can be shown to be the sum of the growth in an appropriately designed input price index ("*Input Prices*") and input quantity index ("*Inputs*").

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs}. \qquad [1]$$

These indexes summarize trends in the input prices and quantities that make up cost. Both indexes use the cost share of each input group that is itemized in index design as weights. A cost-weighted input price index measures the impact of input price inflation on the cost of a bundle of inputs. A cost-weighted input quantity index measures the impact of input quantity growth on cost. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by power distributors such as CMP.

The calculation of input quantity indexes is complicated by the fact that firms typically use numerous inputs in service provision. This complication can be contained when summary input price indexes are readily available for a group of inputs such as labor. Rearranging the terms of [1] we obtain

$$\textit{growth Inputs} = \textit{growth Cost} - \textit{growth Input Prices}. \qquad [2]$$

Input quantity growth is calculated as the growth in inflation-adjusted (a/k/a "real") cost.

This is the approach to input quantity trend calculation that is most widely used in utility productivity research. We can, for example, calculate the growth in the quantity of labor by taking the difference between salary and wage expenses and a salary and wage price index.

2.1.2 Productivity Indexes

Basic Idea

A productivity index is the ratio of an output quantity index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [3]$$

It is used to measure the efficiency with which firms convert production inputs into outputs. Some productivity indexes are designed to measure productivity *trends*. The growth trend of such a productivity index is the *difference* between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [4]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is due to fluctuations in output and the uneven timing of certain expenditures. Volatility tends to be greater for individual companies than for an aggregation of companies such as a regional industry.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple inputs. A *total factor* productivity ("TFP") index measures productivity in the use of *all* inputs. Indexes used in ARM design are sometimes called TFP indexes, but are better described as MFP indexes because multiple input categories are considered but some inputs (*e.g.*, purchased power) are usually excluded.

Output Indexes

The output (quantity) index of a firm or industry summarizes trends in individual outputs. Growth in each output dimension that is itemized is measured by a subindex. In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should be its share of revenue.[1] In this report we denote a revenue-weighted output index by $Outputs^R$. A productivity index that is calculated using $Outputs^R$ will be labeled $Productivity^R$.

$$trend\ Productivity^R = trend\ Outputs^R - trend\ Inputs. \qquad [5a]$$

Another possible objective of output research is to measure the impact of output growth on *cost*. In that event it can be shown that the subindexes should measure the dimensions of operating scale or "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers. The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity". Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multi-category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver. A productivity index that is calculated using a cost-based output index will be labeled $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [5b]$$

This may fairly be described as a "cost efficiency index".

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than the scale of operations. A company's potential to achieve incremental scale economies

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[1] This approach to output quantity indexation was developed by the French economist Francois Divisia.

depends on the pace of its workload growth. Incremental scale economies (and thus productivity growth) will typically be reduced the slower is output growth.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology and other external business conditions allow. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current efficiency level.

Another driver of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and workload growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. Because underground lines are more costly, an increase in the percentage of lines that are undergrounded will tend to slow MFP growth.

When productivity is calculated using a revenue-based output index it is easy to show that the trend in $Productivity^R$ can be decomposed into the trend in the cost efficiency index and the difference between the trends in revenue- and cost-based output indexes.

$$trend\ Productivity^R$$
$$= trend\ Productivity^C + (trend\ Outputs^R - trend\ Outputs^C) \quad [6]$$

This difference in parentheses, which we will call the "output differential", addresses the different ways that output growth affects revenue and cost. The output differential can be an important driver of $Productivity^R$ growth. For example, if $Outputs^C$ is growing more rapidly than $Outputs^R$, growth in $Productivity^R$ can be materially slowed.

2.2 Use of Index Research in ARM Design

Research on the input price and productivity trends of utilities has been used for more than twenty years to design ARMs. This approach produces automatic adjustments for changing business conditions without weakening a utility's performance incentives. The indexing approach also has the benefit of exposing the utility to an external productivity growth standard. The utility can bolster earnings by achieving productivity growth that is superior to the standard. For this reason, ARPs that feature index-based ARMs are sometimes called performance-based rate making ("PBR") plans.

This approach to ARM design originated in the United States where detailed, standardized data on costs of a large number of utilities have been available for many years from state and federal agencies. First applied in the railroad industry, index-based ARMs have subsequently been used to regulate telecom, gas, electric, and oil pipeline utilities. Maine was one of the first jurisdictions to use this approach in energy utility regulation. The methodology is now used in several additional countries.

ARMs based on indexing research are now used more widely to regulate utilities in Canada than in the United States. For example power distributors in Ontario currently operate under PBR plans with index-based ARMs. All gas and electric distributors in Alberta are required to operate under PBR plans with index-based ARMs.

2.2.1 Price Cap Indexes

Early work to use indexing in ARM design focused chiefly on *price* cap indexes ("PCIs"). We begin our explanation of the logic for such research (a/k/a "index logic") by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[2] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost}. \qquad [7]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*") and billing determinants.

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}. \qquad [8]$$

Recollecting from [2] that the trend in cost is the sum of the growth in cost-weighted input price and quantity indexes, it follows that the trend in output prices that permits revenue to track cost is the difference between the trends in an input price index and a multifactor productivity index of MFP^R form.

$$\textit{trend Output Prices}^R = \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [9]$$

[2] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

$$= trend\ Input\ Prices - trend\ MFP^R.$$

The result in [9] provides a conceptual framework for the design of PCIs of general form

$$trend\ Rates = trend\ Inflation - X. \qquad [10a]$$

Here X, the "X factor", is calibrated to reflect a base MFP^R growth target ("$\overline{MFP^R}$"). A "stretch factor", established in advance of plan operation, is sometimes added to the formula. The stretch factor slows PCI growth in a manner that shares with customers the financial benefits of performance improvements that are expected during the ARP.[3]

$$X = \overline{MFP^R} + Stretch \qquad [10b]$$

Since the X factor often includes *Stretch* it is sometimes said that index research has the goal of "calibrating" X.

Recall now from [6] that the trend in MFP^R can be decomposed into the trends in a cost efficiency index and an output differential. We can therefore logically decompose the MFP^R growth target of a price cap index into a cost efficiency growth target ("$\overline{MFP^C}$"), a stretch factor, and an output differential target.

$$X = \overline{MFP^C} + \overline{Output\ Differential} + Stretch. \qquad [10c]$$

For energy distributors like CMP, the difference between the trends in *revenue-* and *cost-based* output indexes is usually similar to the trends in the average use of energy of residential and commercial ("R&C") customers. This is so because the volumes delivered to these customers are the chief drivers of *revenue* whereas the number of R&C customers is the chief driver of *cost*. This means that the X factor for the price cap index of an energy distributor is sensitive to the trend in average use. X factors for utilities experiencing declining average use should therefore typically be much lower than those for utilities experiencing brisk growth in average use. Growth in average use has slowed considerably in the northeast United States in recent years due to sluggish economic growth and the ramp up of demand side management ("DSM") programs.

[3] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

2.2.2 Revenue Cap Indexes

General Formulas

Mathematical theory can also be used to design revenue cap escalators that are based on rigorous input price and productivity research. Such escalators can be called revenue cap indexes ("RCIs"). Several approaches to the design of RCIs are consistent with index logic.

One approach is grounded in the following basic result of cost research:

$$\textit{trend Cost} = \textit{trend Input Prices} - \textit{trend Productivity}^C + \textit{trend Outputs}^C. \qquad [11a]$$

Cost growth is the difference between input price and cost efficiency growth plus the growth in operating scale, where growth in scale is measured by the same cost-based output index that is used to calculate productivity growth. This result provides the basis for a revenue cap escalator of general form

$$\textit{trend Revenue} = \textit{trend Input Prices} - X + \textit{trend Outputs}^C \qquad [11b]$$

where

$$X = \overline{MFP^C} + \textit{Stretch}. \qquad [11c]$$

Cost escalation formulas like [11a] have been used by the Essential Services Commission in the populous state of Victoria, Australia to establish multiyear O&M budgets for gas and electric distributors.

In gas and electric power distribution the number of customers served is an especially important output variable driving cost in the short and medium term. To the extent that this is true, $\textit{Outputs}^C$ can be reasonably approximated by growth in the number of customers served and there is no need for the complication of a multidimensional output index with cost elasticity weights. Relation [11a] can be restated as

$$\begin{aligned} &\textit{trend Cost} \\ &\quad = \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &\quad = \textit{trend Input Prices} - \textit{trend } MFP^N + \textit{trend Customers} \qquad [12a] \end{aligned}$$

where MFP^N is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [12a] we obtain

$$\begin{aligned} &\textit{trend Cost} - \textit{trend Customers} \\ &\quad = \textit{trend (Cost/Customer)} = \textit{trend Input Prices} - \textit{trend } MFP^N. \qquad [12b] \end{aligned}$$

This provides the basis for the following revenue per customer ("RPC") index formula.

$$trend\ Revenue/Customer = trend\ Input\ Prices - X \qquad [12c]$$

where

$$X = \overline{MFP^N} + Stretch\ .$$

This general formula for the design of a revenue cap escalator is currently used in the ARPs of Gazifere, ATCO Gas, and AltaGas in Canada. The Regie de l'Energie in Quebec recently directed Gaz Metro to develop an ARP featuring revenue per customer indexes. Revenue per customer indexes have also been used by Southern California Gas and Enbridge Gas Distribution ("EGD"), the largest gas distributors in the US and Canada, respectively.

We can, alternatively, rearrange the terms of [12a] to obtain

$$trend\ Cost = trend\ Input\ Prices - (trend\ MFP^N - trend\ Customers) \qquad [12d]$$

This provides the basis for the following revenue cap formula, which has a consolidated X:

$$trend\ Revenue = trend\ Input\ Prices\ \text{-}\ X^{Consolidated} \qquad [12e]$$

where

$$X^{Consolidated} = \overline{MFP^N} + Stretch - trend\ Customers^{Forecasted}. \qquad [12f]$$

2.2.3 Choosing a Productivity Peer Group

Research on the productivity of other utilities can be used in several ways to calculate base productivity targets. Using the productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. A competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 2.1.2 of the sources of productivity growth implies that differences in the external business conditions driving productivity growth can cause utilities to have different productivity trends. For example, power distributors that are experiencing slow growth in the number of electric customers served are less likely to realize economies of scale than distributors that are experiencing rapid growth. Similarity in input prices is also important in reducing expected windfalls. There is thus considerable interest in methods for customizing X factors to reflect local business condition. The most common approach to date has been to calibrate the X factor for a utility using the input price and productivity trends of *similarly situated* (a/k/a "peer") utilities. The utilities are usually but not always chosen from the surrounding region.

2.2.4 Inflation Measure Issues

Index logic suggests that the inflation measure of an ARM should track the input price inflation of utilities. For incentive reasons, it is preferable that the inflation measure track the input price inflation of utilities generally rather than the prices actually paid by the subject utility.

Several issues in the choice of an inflation treatment must still be addressed. One is whether the inflation measure should be *expressly* designed to track utility industry input price inflation. There are several precedents for the use of utility-specific inflation measures in ARP rate escalation mechanisms. Such a measure was used in one of the world's first large-scale ARPs, which applied to U.S. railroads. Such measures have also been used in ARPs for Canadian railroads and for energy utilities in Alberta, California, and Ontario. The development of industry-specific input price indexes for energy utilities is facilitated by the availability of indexes for certain utility inputs from respected private vendors.

Notwithstanding such precedents, the majority of indexed-based ARMs approved worldwide do not feature industry-specific input price indexes. They instead feature measures of economy-wide (a/k/a "macroeconomic) price inflation. Gross domestic product price indexes ("GDPPI's") are most widely used for this purpose in North America. In the United States, the GDPPI is computed on a quarterly basis by the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce. It is the federal government's featured measure of inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products. The GDPPI thus grows at a rate that is similar to that of the consumer price index ("CPI"). However, the GDPPI tracks inflation in a broader range of products that includes government services and capital equipment. The broader coverage makes the GDPPI less sensitive to volatility in prices of inputs, such as gasoline and foodstuffs, that have little impact on utility cost. The Maine PUC has approved the use of the GDPPI in previous PBR plans for CMP.

Macroeconomic inflation measures have some advantages over industry-specific measures in rate adjustment indexes. One is that they are available, at little or no cost, from government agencies. There is then no need to go through the chore of annually recalculating complex indexes or purchasing costly utility inflation data from private vendors. Another advantage is that customers are more familiar with macroeconomic price indexes (especially CPIs). The sizable task of designing an industry-specific price index during the proceeding that establishes the ARM is also sidestepped. The design of a capital price for such an index can be especially controversial.

When a macroeconomic inflation measure is used, the ARM must be calibrated in a special way if it is to reflect industry cost trends. Suppose, for example, that the inflation measure is a GDPPI. In that event we can restate the cost growth formula in [12d], for example, as

$$\begin{aligned}&\textit{trend Cost} = \textit{trend GDPPI} - [\textit{trend MFP}^N + \\ &\qquad (\textit{trend GDPPI} - \textit{trend Input Prices}) - \textit{trend Customers}] \qquad [13]\end{aligned}$$

It follows that an ARM with the GDPPI as the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth.

Consider now that the GDPPI is a measure of *output* price inflation. Due to the broadly competitive structure of the U.S. economy, the long-run trend in the GDPPI is then the difference between the trends in input price and MFP indexes for the economy.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{Economy} - \textit{trend MFP}^{Economy}. \qquad [14]$$

Provided that the input price trends of the industry and the economy are similar, the growth trend of the GDPPI can thus be expected to be slower than that of the industry-specific input price index by the trend in the economy's MFP growth. In a period of rapid MFP growth this difference can be substantial. When the GDPPI is the inflation measure, the ARM therefore already tracks the input price and MFP trends of the economy. X factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy.

Relations [13] and [14] can be combined to produce the following formula for a revenue cap escalator.

$$trend\ Revenue = trend\ GDPPI - \left[\begin{array}{l}\left(trend\ MFP^{Industry} - trend\ MFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) + Stretch - growth\ Customers^{Forecasted}\end{array}\right] \quad [15]$$

This formula suggests that when the GDPPI is employed as the inflation measure, the revenue cap index can be calibrated to track industry cost trends when the X factor has a productivity differential and an input price differential. The productivity differential is the difference between the MFP trends of the industry and the economy. X will be larger (smaller), slowing (accelerating) revenue growth, to the extent that the industry MFP trend exceeds (is less than) the economy-wide MFP trend that is embodied in the GDPPI. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.

The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the industry grow at different rates than prices for the same inputs in the economy as a whole. For example, labor prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also noteworthy that the energy distribution industry has a different and more capital-intensive mix of inputs than the economy.

2.2.5 Revenue Decoupling

Revenue decoupling is an approach to utility rate regulation that decouples a utility's revenue (and thus its earnings) from its delivery volumes and other dimensions of system use. The most common approach to decoupling is the decoupling true up plan. In such a plan, a revenue decoupling mechanism ("RDM") typically ensures that the revenue ultimately received by the utility equals the revenue requirement ("RR") allowed revenue regardless of system use. Assuming for simplicity that decoupling occurs instantaneously, decoupling is typically achieved using an adjustment to "preliminary" revenue such as the following.

$$Revenue^{Final} = Revenue^{Preliminary} + (RR - Revenue^{Preliminary}). \qquad [16]$$

The revenue requirement in a decoupling true up plan is usually subject to escalation using some kind of ARM, and this usually takes the form of an allowed revenue cap. Since a utility's cost tends to grow, it will be compelled to file frequent rate cases under revenue decoupling in the absence of an ARM. The revenue cap indexes discussed in Section 2.2.2 are therefore useful escalators.

2.2.6 Long-Run Productivity Trends

An important issue in the design of a PCI is whether it should be designed to track short-run or long-run unit cost growth. An index designed to track short-run growth will also track the long-run growth trend if it is used over many years. An alternative approach is to design the index to track *only* long-run trends. Different approaches can, in principle, be taken for the input price and productivity components of the index.

Different treatments of input price and productivity growth are in most cases warranted when a PCI is calibrated to track the industry unit cost trend. The inflation measure should track *short-term* input price growth. The X factor, meanwhile, should generally reflect the long-run historical trend of MFP.

This general approach to PCI design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the PCI responsive to short-term input price growth reduces utility operating risk without weakening performance incentives. Having X reflect the long-run industry MFP trend, meanwhile, sidesteps the need for more timely cost data and avoids the chore of annual MFP calculations.

To calculate the long-run productivity trend using indexes it is common to use a lengthy sample period. The sample period should be at least ten years. However, a period of more than twenty years may be unreflective of the current state of technological change. Moreover, consistent series of quality data are often unavailable for sample periods of longer length. The need for a long sample period is lessened to the extent that the output index does not assign a heavy weight to volatile output measures such as delivery volumes.

2.2.7 Dealing With Cost Exclusions

Many multiyear rate plans recover certain costs outside of the ARM. In PBR plans, costs that are targeted for exclusion are sometimes said to be "Y factored". The exclusions affect the research that is appropriate for calibrating the X factor. Suppose, for example, that costs of taxes and pensions are going to be Y factored under the ARP. These costs should then be excluded from the definition of cost that is used in the MFP research.

2.2.8 Data Quality

The quality of data used in index research has an important bearing on the relevance of results for the design of IR plans. Generally speaking, it is desirable to have publicly available data drawn from a standardized collection form such as those developed by government agencies. The best quality data of this kind are gathered by commercial venders that put in extra effort to ensure their quality and spread the cost of their work amongst numerous subscribers. Data quality also has a temporal dimension. It is customary for statistical cost research used in ARP design to include the latest data available.

2.3 Supplemental Capital Cost Funding

In many PBR plans supplemental revenue is available for special capital expenditures programs that cannot be funded by the index-based ARM. The most common form of supplemental capex funding is the capital cost "tracker". Key decisions to be made in the approval of such trackers are determination of the need for special treatment of capex, what types of projects should be afforded special treatment, and the timing of prudence reviews.

Out of the many North American regulators that have approved index-based PBR plans to date, only a few do not appear to have allowed a special ratemaking treatment for recovery of the cost of specific types of capital expenditures in any of their approved PBR plans for electric and gas utilities. Regulators in neighboring Vermont and

Massachusetts, for example, have approved special treatments of supplemental capex in PBR plans for at least one of their electric distributors. Here are additional details on some provisions for supplemental funding of capex in PBR plans of energy utilities in Alberta, British Columbia and Ontario in Canada and Massachusetts in the US.

2.3.1 Alberta

As part of its recent decision approving PBR plans for most provincial energy distributors, the AUC approved capital cost recovery mechanisms called capital trackers. The AUC established three eligibility criteria for tracker ratemaking treatment:

1) The project must be outside of the normal course of the company's ongoing operations.
2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
3) The project must require a material amount of funding.[4]

Utilities will be allowed to file capital tracker proposals on March 1st of each year for implementation in the following calendar year. Amounts that will be recovered under the capital tracker will reflect forecasted amounts with revenue requirements limited to the depreciation, taxes, and return on the incremental investment. There will be periodic true ups of forecasted to actual cost.

2.3.2 British Columbia

For both of the PBR plans of BC Gas (d/b/a FortisBC Energy), special treatments for capex requiring certificates of public convenience and necessity ("CPCNs") were outlined in the PBR settlements. In the first PBR plan, these projects were described as "capital projects which BC Gas foresees as being required within the Term, but have not been developed sufficiently…, or projects which are not foreseen but could be required".[5] Some examples of the former category were the Southern Crossing pipeline, automated meter reading, and various IT projects. An example of the latter category was the relocation of an urban transmission pipeline. The ratemaking treatment of CPCN

[4] Alberta Utilities Commission Decision 2012-237, p. 126.
[5] Consolidated Settlement Document, BC Gas Utility Ltd. 1998-2000 Revenue Requirements, page 9.

investments was similar in BC Gas' second PBR plan. The settlement generally excluded CPCNs for projects under $5 million and indicated that fewer CPCNs were expected during the second PBR plan.

2.3.3 Ontario

The settlement outlining the 2008-2012 Enbridge Gas index-based PBR plan also outlined a special treatment of capital in the form of a Y factor for capital required to connect electric gas-fired generating facilities to Enbridge's system. In order to qualify for Y factor treatment, the Ontario Energy Board would need to approve the investment in a "leave to construct" proceeding. This proceeding would also determine the budget that could be recovered through the Y factor after the project has been placed into service.

The index-based third generation PBR mechanism for Ontario's power distributors features two ratemaking treatments of capex outside of the index-based ARM. One is a treatment for capex that results from government mandates (in the case of Ontario, smart meters is an example). There is also an Incremental Capital Module that companies can request for specific non-governmentally mandated capital projects. The Board described the Incremental Capital Module as "reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[6] During the course of the third generation PBR term, the phrase "unusual circumstances" has been dropped from the criteria for Incremental Capital Module approval. Underspending will result in refunds to ratepayers.

There have over the years been 12 applications by 11 companies for an ICM. Of these, 9 have been approved, 2 were rejected, and 1 was withdrawn before a decision was rendered. The two largest distributors in Ontario, Hydro One Networks and Toronto Hydro Electric, have approved ICMs. ICMs have been used primarily for replacement capex that was out of the ordinary.

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[6] Ontario Energy Board Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, p. 31. Filed September 17, 2008 in EB-2007-0673.

The fourth generation ARP for Ontario's power distributors is under development. It is expected to feature three ratemaking options: a British-style forecast-based approach to ARM design for distributors expecting chronically high capex, a price cap mechanism that would continue to feature the Incremental Capital Module as an option for distributors with lumpier capex needs, and a simplified price cap for distributors that anticipate a steady level of capex. A final decision on the fourth generation PBR for Ontario's power distributors is pending.

2.3.4 Massachusetts

Nstar Electric's PBR plan was outlined in a 2005 settlement between the company and intervenors which was approved by the Massachusetts Department of Telecommunications and Energy. The settlement committed Nstar to spend no less than $10 million in each year of the plan in addition to the cost presumed to be in base rates in each year of the plan in order to address safety-related issues. The revenue requirement associated with the investment, consisting of depreciation, return on investment, taxes, and O&M expenses, was recoverable in rates if the investment was determined to be prudent. A second special capital cost recovery mechanism for Nstar was approved in 2010 due to a change in state law requiring utilities in Massachusetts to file smart grid pilot programs by April 1, 2009. Nstar requested and received approval for recovery of 50% of its incremental expenditures outside of the indexing mechanism.

3. EMPIRICAL WORK FOR CMP

This section presents an overview of our index research to develop an ARM for the Company's new ARP. The discussion is largely non-technical. Additional details of the work are provided in Exhibit SUP-MNL-1.

3.1 Data

The primary source of the cost and quantity data used in the study was the Federal Energy Regulatory Commission ("FERC") Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Cost and quantity data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

FERC Form 1 data are processed by the Energy Information Administration ("EIA") of the U.S. Department of Energy. Selected Form 1 data were for many years published by the EIA.[7] More recently, the data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained from one such vendor, SNL Financial.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the Northeast that filed the Form 1 electronically in 2001 and that, together with any important predecessor companies, have reported the necessary data continuously since the 1960s.[8] To be included in the study the data were required, additionally, to be of good quality and plausible. Data from 14 companies in the upper Northeast and for 24 companies in the broad Northeast met these standards and were used in our indexing work. The data for these companies are the best available for rigorous work on input price and productivity trends to support the development of an X factor for CMP. The companies included in the indexing work are listed in Tables MNL-1 a and b.

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[7] This publication series had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*

[8] We require capital cost data for decades prior to the sample period, as we explain further in Exhibit Sup-MNL-1 Section A.1.2.

Table MNL-1a

Companies in the Upper Northeast Productivity Peer Group

New England

Bangor Hydro-Electric	Massachusetts Electric
Central Maine Power	Narragansett Electric
Central Vermont Public Service	NSTAR Electric
Connecticut Light and Power	United Illuminating
Green Mountain Power	Western Massachusetts Electric
Maine Public Service	

Upstate New York

Central Hudson Gas & Electric	Orange & Rockland
New York State Electric & Gas	

Table MNL-1b

Companies in the Broad Northeast Productivity Peer Group

New England

Bangor Hydro-Electric	Massachusetts Electric
Central Maine Power	Narragansett Electric
Central Vermont Public Service	NSTAR Electric
Connecticut Light and Power	United Illuminating
Green Mountain Power	Western Massachusetts Electric
Maine Public Service	

New York

Central Hudson Gas & Electric	Orange & Rockland
New York State Electric & Gas	

Mid-Atlantic

Atlantic City Electric	Pennsylvania Electric
Baltimore Gas and Electric	Pennsylvania Power
Duquesne Light	Potomac Electric Power
Jersey Central Power and Light	Public Service Electric and Gas
Metropolitan Edison	West Penn Power

A noteworthy idiosyncrasy of the FERC Form 1 is that it requests data on retail power *sales* volumes but not data on the volumes of *unbundled distribution* services that might be provided under retail competition. Where retail competition exists, this complicates accurate calculation of trends in retail delivery volumes and customers. To address this issue we obtained our output data from Form EIA-861, the *Annual Electric Power Industry Report*. These data were also gathered by SNL Financial.

Other sources of data were also accessed in the research. These were used primarily to measure input price trends. The supplemental data sources were Whitman, Requardt & Associates; the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce; Global Insight; and the BLS. The specific data drawn from these and the other sources mentioned are discussed further below.

3.2 Index Details

3.2.1 Scope

The indexes calculated in this study measured input price and productivity trends of utilities in their role as power distributors. The major tasks in a distribution operation are the local delivery of power and the reduction of its voltage from the level at which it is received from the transmission network.[9] Most power is delivered to end users at the voltage at which it is consumed. Power deliveries must be metered. Distributors also typically provide an array of customer services such as account, sales, and information services.

The costs considered in this study comprised operation and maintenance ("O&M") expenses and the cost of capital. Capital cost includes depreciation, taxes, and a return on plant value. Distributor cost was defined to include sensible shares of a utility's administrative and general ("A&G") expenses and its cost of general plant ownership.

The decomposition of capital cost into prices and quantities is required if we are to measure input price and quantity trends. The study used a service price approach to

[9] The term "distribution" in the Uniform System of Accounts corresponds most closely to local delivery service as here discussed.

effect this decomposition. Under this approach, the cost of capital is the product of a capital quantity index and an index of the price of capital services. This method has a solid basis in economics and has been widely used in scholarly research. The specific approach to capital cost measurement used in this study is designed to mirror the way that capital cost is counted under cost of service ("COS") regulation.

3.2.2 Index Construction

The growth (rate) of each MFP index calculated in this study is the difference between the growth rates of indexes of industry output and input quantity trends. The growth of the output quantity index for the industry is the growth in the total number of customers served. This specification is appropriate for the revenue cap index that the Company is proposing as an ARM.[10] The growth of the input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, power distribution plant, and general plant. The growth of each input price index is a weighted average of the growth in price subindexes for these same input groups.

3.2.3 The Sample

The sample period was 2002-2011. The 2011 end date is the latest year for which all data that we use to calculate the input price and MFP indexes are currently available. The 2002 start date makes it possible to compute a ten year average growth rate and yet is recent enough to avoid most of the years of power industry restructuring that occurred in the Northeast. Appropriate adjustments to the cost data for the effects of restructuring were a source of controversy in CMP's last ARP proceeding. A longer sample period would also require "patching" FERC and EIA output data.

The utilities in the indexing sample were carefully chosen to mitigate controversy and follows principles advocated by Staff in the CMP's last ARP proceeding. Two regions were considered. The upper Northeast region was defined as New England and upper New York State. This region has been used for index research in past ARP proceedings in Maine and has been advocated by Bench Staff. Companies in this region face trends in input prices, output, and other business conditions affecting unit cost

[10] In the productivity index we used in CMP's last ARP filing, the output index was revenue-weighted and placed a heavy weight on delivery volumes because the Company was proposing a price cap index.

growth that are similar to those facing CMP. We also considered a broad Northeast region that includes, additionally, utilities in the District of Columbia, Maryland, Pennsylvania, and New Jersey.

3.3 Index Results

3.3.1 MFP

Tables MNL-2a and 2b and Figure MNL-1 report key results of our MFP research. Findings are presented for the 2002-2011 period for the MFP index and the component output and input quantity indexes. It can be seen that over the full sample period the annual average growth rate in the MFP of sampled power distributors in the upper Northeast was about **0.56%**.[11] Output quantity growth averaged a **0.65%** pace annually while input quantity growth averaged just **0.09%** annually. Output growth in the region has slowed appreciably during the years of CMP's current ARP.

Table MNL-2a also reports the trends in the MFP index for the U.S. private business sector over the 2002-2011 period for which data are available. This index is calculated by the BLS. It can be seen that its **1.11%** average annual growth rate was very similar to the trend in the MFP index for Northeast power distributors. A productivity differential based on the difference between the growth trends of these indexes is **-0.55%**.

Table MNL-2b reports that the MFP growth of sampled utilities in the broad Northeast utilities averaged **1.06%** annually. Output quantity growth averaging **0.62%** annually outpaced input quantity growth that declined by **0.44%** on average. The resultant productivity differential was **-0.05%**.

Table MNL-3 reports MFP results for CMP over the 2002-2011 period. It can be seen that productivity growth averaged **1.68%** per annum, well above the trend for the peer group. Output growth averaging **0.96%** was modestly more rapid than that of the peer groups. Input quantities declined by **0.72%** each year on average. Capital productivity grew more rapidly than O&M productivity. Growth in capital productivity

[11] All growth trends noted in this report were computed logarithmically.

Table MNL-2a

Calculating the Productivity Differential: Upper Northeast

	Productivity Growth				Productivity Differential
	Northeast Power Distributors			U.S. Private Business Sector	
	Output Quantity	Input Quantity	MFP	MFP[1]	
			[A]	[B]	[A]-[B]
2002	0.88%	1.06%	-0.18%	2.40%	-2.58%
2003	1.03%	0.50%	0.53%	2.70%	-2.17%
2004	0.80%	-1.63%	2.42%	2.40%	0.02%
2005	1.00%	0.96%	0.04%	1.00%	-0.96%
2006	0.88%	0.75%	0.14%	0.40%	-0.26%
2007	1.18%	-0.59%	1.77%	0.30%	1.47%
2008	-0.07%	0.73%	-0.80%	-1.20%	0.40%
2009	0.07%	0.58%	-0.51%	-0.10%	-0.41%
2010	0.26%	1.54%	-1.28%	2.50%	-3.78%
2011	0.48%	-3.00%	3.48%	0.70%	2.78%
Average Annual Growth Rate 2002-2011	**0.65%**	**0.09%**	**0.56%**	**1.11%**	**-0.55%**

[1]Source: U.S. Bureau of Labor Statistics

Table MNL-2b

Calculating the Productivity Differential: Broad Northeast

	Productivity Growth				Productivity Differential
	Northeast Power Distributors			U.S. Private Business Sector MFP[1]	
	Output Quantity	Input Quantity	MFP		
			[A]	[B]	[A] - [B]
2002	0.77%	-0.85%	1.61%	2.40%	-0.79%
2003	0.93%	2.62%	-1.68%	2.70%	-4.38%
2004	0.77%	-4.70%	5.46%	2.40%	3.06%
2005	0.96%	0.43%	0.54%	1.00%	-0.46%
2006	0.91%	-0.20%	1.11%	0.40%	0.71%
2007	0.90%	0.72%	0.18%	0.30%	-0.12%
2008	0.15%	-0.56%	0.71%	-1.20%	1.91%
2009	0.19%	-1.69%	1.89%	-0.10%	1.99%
2010	0.33%	1.52%	-1.19%	2.50%	-3.69%
2011	0.32%	-1.65%	1.97%	0.70%	1.27%
Average Annual Growth Rate 2002-2011	**0.62%**	**-0.44%**	**1.06%**	**1.11%**	**-0.05%**

[1]Source: U.S. Bureau of Labor Statistics

Figure MNL-1

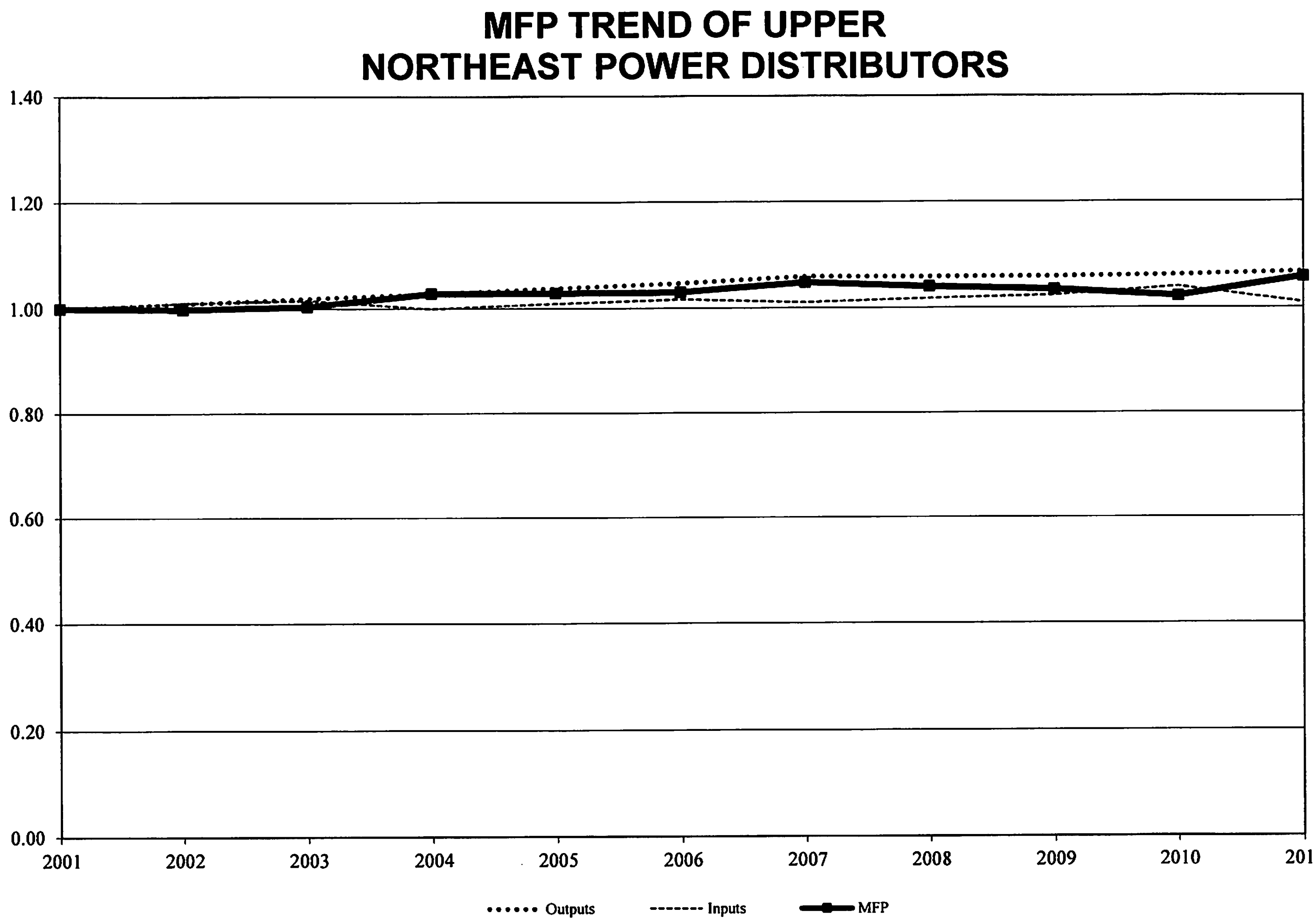

MFP TREND OF UPPER
NORTHEAST POWER DISTRIBUTORS
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Outputs
Inputs
MFP

Table MNL-3

Output, Input, and Productivity Trends of Central Maine Power

Year	Output Quantity [A]	Input Quantity [B]	MFP [A-B]
2002	1.51%	-0.78%	2.29%
2003	1.39%	-1.46%	2.85%
2004	1.47%	-3.93%	5.40%
2005	1.45%	-2.25%	3.70%
2006	1.35%	2.52%	-1.17%
2007	1.39%	-0.63%	2.02%
2008	0.10%	0.17%	-0.08%
2009	0.19%	6.04%	-5.85%
2010	0.43%	-9.33%	9.77%
2011	0.29%	2.44%	-2.15%
Average Annual Growth Rate			
2002-2011	**0.96%**	**-0.72%**	**1.68%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), and Regulatory Research Associates (electric utility allowed ROE) was especially brisk from 2002 to 2006 but has since slowed, and turned negative in 2011.

3.3.2 Input Prices

Table MNL-4 and Figure MNL-2 report key findings of our input price research. From 2002 to 2011, input prices facing sampled upper Northeast distributors were found to average about **3.55%** average annual growth. The input prices facing broad Northeast distributors were found to average **3.44%** annual growth.

An input price index for the U.S. economy is not expressly computed by the federal government, so index logic was used to calculate the economy's input price trend using other government indexes. To the extent that the economy earns a competitive return, the long-term trend in its *input* prices is the sum of the trends in its *output* prices and its TFP. Using GDPPI as the output price index and the MFP index for the U.S. private business sector to measure of the economy's TFP growth, the trend in the economy's input prices can be calculated.

From 2002 to 2011, input prices in the U.S. economy are estimated to have grown at about a **3.20%** average annual rate. This is similar to but a little less than the growth in the input prices facing northeast power distributors. The input price differential resulting from this analysis is thus about **-0.35%** for the upper Northeast and **-0.24%** for the broad Northeast.

3.4 K Factor

CMP increased its plant additions substantially in 2011 in an effort to accelerate modernization of its distribution system. The company expects its distribution capex to continue at higher levels during the term of the proposed ARP. We have developed an adjustment to X, which we call the K factor, which would provide CMP with some supplemental revenue for its construction program. The K factor is based on statistical research on the cost of power distributors and therefore will not weaken CMP's performance incentives or require a review of the Company's capex plan.

The basic idea is to compute how the productivity trends of utilities that started the sample period with capital inputs similar to CMP's recent level differed from the

Table MNL-4

Calculating the Input Price Differential

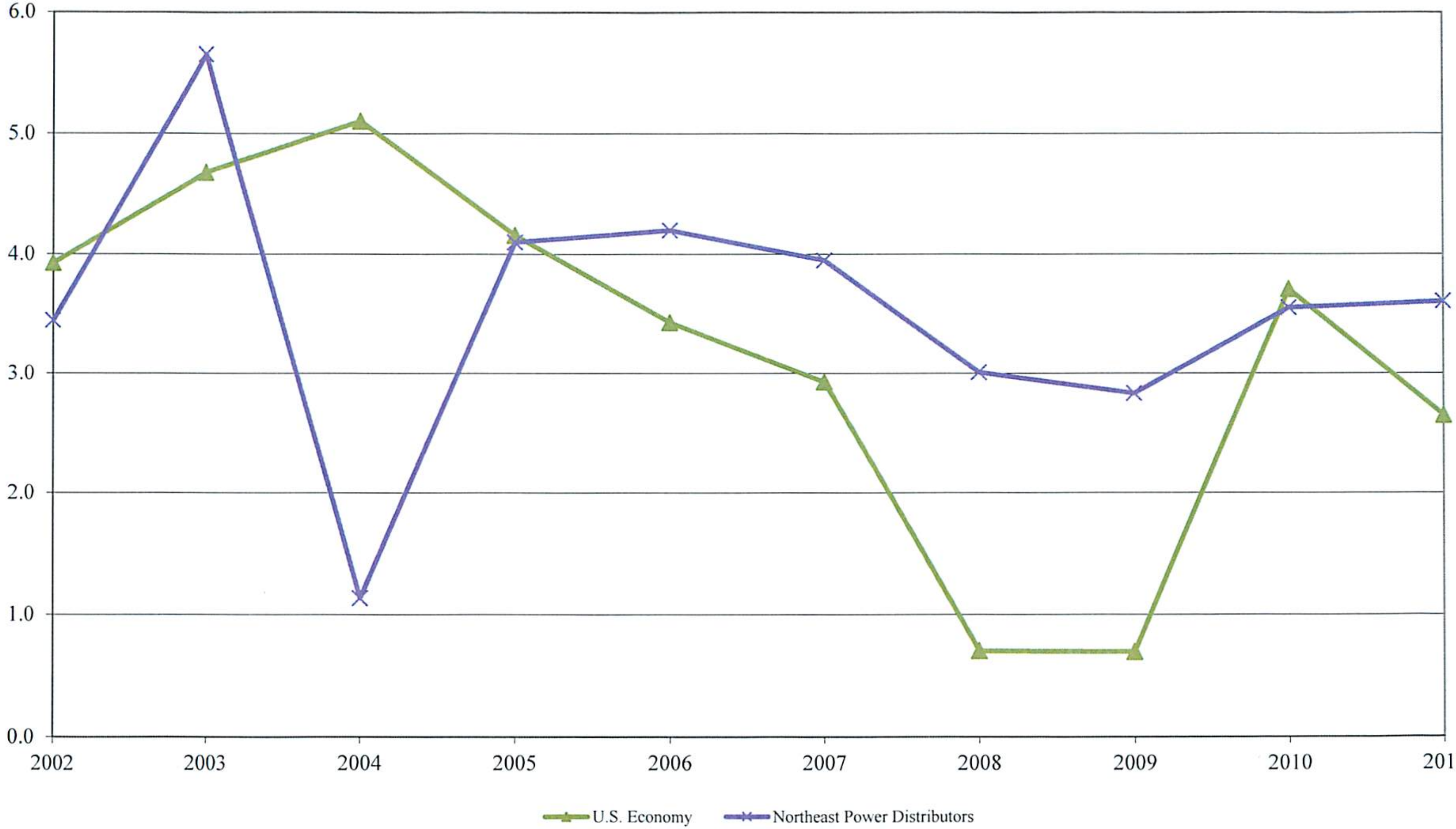
	Input Price Trends					Input Price Differential	
	United States			Power Distributors			
	GDP-PI[1]	MFP[2]	Implied IPI	Upper Northeast	Broad Northeast	Upper Northeast	Broad Northeast
	[A]	[B]	[C=A+B]	[D1]	[D2]	[E=C-D1]	[E=C-D2]
	(%)	(%)	(%)	(%)	(%)	(%)	(%)
2002	1.53	2.40	3.93	3.44	3.17	0.48	0.76
2003	1.98	2.70	4.68	5.65	4.19	-0.97	0.48
2004	2.70	2.40	5.10	1.13	1.61	3.97	3.49
2005	3.16	1.00	4.16	4.10	3.98	0.06	0.17
2006	3.03	0.40	3.43	4.20	3.93	-0.77	-0.50
2007	2.63	0.30	2.93	3.95	3.18	-1.02	-0.25
2008	1.90	-1.20	0.70	3.01	3.19	-2.30	-2.49
2009	0.80	-0.10	0.70	2.83	3.94	-2.14	-3.24
2010	1.21	2.50	3.71	3.55	3.16	0.15	0.55
2011	1.95	0.70	2.65	3.60	4.06	-0.96	-1.41
Average Annual Growth Rate 2002-2011	**2.09%**	**1.11%**	**3.20%**	**3.55%**	**3.44%**	**-0.35%**	**-0.24%**

[1] Gross Domestic Product Price Index calculated by the BEA.

[2] Multifactor productivity for the U.S. private business sector calculated by the BLS.

Figure MNL-2

INPUT PRICE TRENDS FOR U.S. ECONOMY & UPPER NORTHEAST POWER DISTRIBUTORS



average productivity trend of utilities in a region. This research involves a multistage process. We first developed an econometric capital cost benchmarking model, the parameters of which were estimated using cost and other operating data from a national sample of US power distributors. In 2011, the most recent year of our sample period, CMP's capital cost was about 21% below the model's predictions. This was one of the better capital cost containment performances in the US sample.

The second step in the analysis was to consider how the average MFP growth of a peer group of utilities with a capital cost score close to **21%** on average *in 2001*, at the start of the sample period, differed from the average MFP growth of all utilities. This exercise was conducted for each Northeast region. Theory suggests that these utilities might need to rebuild their capital stock and in the process experience slow productivity growth. To preserve strong performance incentives for CMP it is excluded from the low-capital peer group.

The sampled utilities in the upper Northeast averaged **0.56%** annual MFP growth, as previously noted. The peer group of utilities with initially low capital inputs averaged, in contrast, **-0.06%** productivity growth. The resultant productivity growth differential was **-0.63%**. This is the indicated K factor for this region.

As for the broad Northeast, the sampled utilities averaged **1.06%** annual MFP growth, as previously noted. The peer group of utilities with initially low capital inputs averaged, in contrast, **0.70%** productivity growth. The resultant productivity growth differential was **-0.36%**.

3.5 Stretch Factor

The stretch factor term of an X factor should reflect the expectation of improved performance under the ARP. This depends on the company's operating efficiency at the start of the plan, and on how the performance incentives generated by the ARP compare to those in force for sampled utilities during the index sample period. CMP's impressive productivity growth under previous ARPs should have brought it to a level of performance that is at least average for the industry, and possibly better.

Performance incentives under the ARP are strengthened by the proposed five-year term but weakened by the proposed sharing of surplus earnings. Meanwhile, rate cases were filed on average every 4.8 years by utilities in the upper Northeast during the sample period and every 5.9 years by utilities in the broad Northeast. In the broad Northeast most utilities were not subject to earnings sharing mechanisms.

The productivity trend of the sampled utilities should therefore reflect the impact of performance incentives that were as strong or, in the case of the broad Northeast, actually stronger than those which CMP will likely face. For an average cost performer, no acceleration in MFP growth could be expected from operating under the ARP proposed by CMP. Based on this reasoning, together with the observation that CMP has just experienced a period of rapid MFP growth unlikely to be replicated, an appropriate stretch factor for CMP should be 0.00%.

3.6 Indicated X Factor

Assuming the use of GDPPI as the inflation measure, our research using upper Northeast data suggests that the consolidated X factor for a revenue cap index for CMP is **-1.90%**. This is the sum of a **-0.55%** productivity differential, a **-0.35%** input price differential, a **-0.63%** K factor, a stretch factor of **0.00%**, and a **-0.37%** offset for CMP's forecasted customer growth.

Using data for the broad Northeast, our research suggests that the consolidated X factor for a revenue cap index for CMP is **-1.02%**. This is the sum of a **-0.05%** productivity differential, a **-0.24%** input price differential, a **-0.36%** K factor, a stretch factor of **0.00%**, and a **-0.37%** offset for customer growth.

EXHIBIT SUP-MNL-1

This exhibit contains additional details of our new price and productivity research for CMP. Section A.1 addresses our calculation of distribution cost. Sections A.2 and A.3 address the input price and input quantity indexes, respectively. Section A.4 discusses the econometric capital cost model.

A.1 Distribution Cost

A.1.1 Total Cost

The total cost of power distribution considered in the study was the sum of applicable O&M expenses and capital costs. Applicable O&M expenses included those for distribution, sales, and customer accounts other than those for uncollectible bills, plus a sensible share of the company's total A&G expenses. Uncollectible bill expenses were excluded because they exhibited a rising trend, due to weak economic growth, that is likely to be atypical of the long-term trend. Customer service and information expenses were excluded because they have been increasingly dominated by DSM expenses, which would be subject to separate ratemaking treatment under the ARP. Assigned capital cost consisted of the cost of distribution plant and a sensible share of the cost of general plant.

A&G expenses are O&M expenses that are not readily assigned directly to particular operating functions under the Uniform System of Accounts. They include expenses incurred for pensions and other benefits, injuries and damages; property insurance, regulatory proceedings, stockholder relations, and general advertising of the utility; the salaries and wages of A&G employees; and the expenses for office supplies, rental services, outside services, and maintenance activities that are needed for general administration.

General plant is plant that is not directly assigned to particular operating functions in the Uniform System of Accounts. Certain structures and improvements (*e.g.*, office buildings), communications equipment, office furniture and equipment, and transportation equipment account for the bulk of general plant value. Other general plant categories in the Uniform System of Accounts include tools, shop, and garage equipment, laboratory equipment, miscellaneous power-operated equipment, land and land rights, and stores equipment.

A.1.2 Dealing with Capital in Productivity Research

Introduction

Trends in the price and quantity of capital play a critical role in measurement of trends in the MFP and prices of utility base rate inputs. Summary input price and quantity indexes are, after all, cost-weighted, and capital typically accounts for half or more of total cost. A practical means must thus be found to calculate capital cost, and to decompose it into consistent price and quantity indexes such that

$$trend\ Cost^{Capital} = trend\ Price^{Capital} + trend\ Quantity^{Capital}. \quad [A1]$$

Capital prices can be volatile. Disagreement over capital price trends has made calculation of the input price differential a controversial issue in some North American ARP proceedings.

The capital quantity index is, effectively, an index of the trend in the real (inflation-adjusted) cost of depreciated plant. Indexes of construction costs are commonly used to measure plant-addition price trends in utility productivity research. The rate base of an energy distributor tends to grow over time due to system expansion and inflation of construction prices. However, capital quantity indexes of energy distributors sometimes display a negative trend.

The capital price index measures the trend in the cost of owning a unit of capital. It is sometimes called a "rental" or "service" price index because, in a competitive rental market, the trend in prices tends to reflect the trend in the unit cost of capital ownership. The monthly charge for an automobile lease, for instance, should reflect the monthly cost to the lessor of owning the automobile.

The components of capital cost include depreciation and the return on investment. Capital cost thus depends on construction prices, depreciation rates, and the rate of return on capital. A capital service price index should reflect the trends in these conditions.

A utility's rate of return reflects returns on various kinds of investments, and rates of returns on different kinds of investments can differ markedly. Yields on long-term bonds, for instance, soared on the occasion of the second oil price shock and then fell gradually for many years. Returns on equity have displayed a less pronounced downward trend.

Utilities have diverse methods for calculating depreciation expenses. In calculating capital costs and quantities, it is therefore desirable in productivity research to rely chiefly on the companies for the value of plant *additions* and then use a standardized depreciation treatment to construct a capital quantity index. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, data on plant additions for many years in the past are needed. For some of the earliest years for which plant addition data are needed, however, the data are often unavailable and the plant additions must be imputed using aggregate plant value data and construction price indexes for a certain early "benchmark" year.

Three practical methods have been developed for calculating capital costs that can be decomposed into input price and quantity indexes: geometric decay, one hoss shay, and cost of service. All have been used over the years in CMP's productivity evidence. The choice of a capital costing methodology is an important issue in X factor calibration.

Geometric Decay

The critical assumptions of the geometric decay ("GD") approach are twofold.

- Utility plant is valued in *current* dollars, so that plant values reflect the cost of asset replacement.
- Plant depreciates at a constant rate.

Both assumptions differ from those used in computing capital cost in North American utility rate regulation.

Current valuation of plant means that owners profit from capital gains. If the value of assets is rising, the *net* cost of plant ownership can be appreciably less than the *gross* due to capital gains. The capital service price should then reflect the expected net cost of owning a unit of plant.

Abstracting from taxes, here is a GD capital service price that corresponds to these assumptions.

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot r - E(WKA_t - WKA_{t-1}). \qquad [A2]$$

Here the term d is the (constant) rate of depreciation. The term WKA_t is the current price of a unit of utility plant. In a competitive market for construction services this would equal, in the long run, the cost to construct a unit of plant. Accordingly, the trend in WKA_t is commonly measured using construction cost indexes. The term r_t is the cost of obtaining a dollar of funds in capital markets.

Examining equation [A2] it can be seen to contain three groups of terms. The first corresponds to the cost of depreciation, the second to the opportunity cost of capital, and the third term to expected capital gains. The last two terms can be consolidated into one term that represents the expected real (inflation-adjusted) rate of return on capital ownership. The service price can then be restated as

$$WKS_{jt} = d \cdot WKA_{j,t} + WKA_{j,t-1} \cdot E\left[r_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}} \right]. \qquad \text{[A3]}$$

The term in brackets is the real rate of return.

While GD service price equations are mathematically elegant, they have serious practical implementation problems in an X factor calibration exercise. One is that there is no established method of modeling the expected growth of the real rate of return. Another problem is the unusual instability of GD service prices, which stems from the fact that the rate of return does not always rise in tandem with asset price (or construction cost) inflation. The real rate of return is, in practice, considerably more volatile than the nominal rate of return that matters in COS regulation. In recent years, for example, it has sometimes been negative as a falling rate of return coincided with rapid growth in construction costs.

The instability of the capital service price using the GD approach to capital costing means that it must be smoothed before its trend can be calculated. Different approaches to smoothing have materially different effects on trend calculations. The proper approach to smoothing can be a source of dispute, and smoothing does not always eliminate service price volatility.

The GD method has nonetheless been widely used in productivity research. Despite the controversy that can arise over input price differentials, it has been used several times in index research intended to calibrate X factors. One example was the X factor testimony of Dr. Lowry in CMP's first price cap filing. This approach was also used by Dr. Phil Schoech in research for Bench Staff during the last ARP proceeding.

One Hoss Shay

The one hoss shay approach to capital costing assumes that plant does not depreciate gradually but, rather, all at once as the asset reaches the end of its service life. The plant is valued in current dollars, so that capital gains and capital price volatility are once again issues. Although the assumptions underlying the one hoss shay method are very different from those used to compute capital cost in utility regulation, the method has been used occasionally in research intended to calibrate utility X factors. An example is the research supporting the testimony of Dr. Jeff Makholm in CMP's second price cap filing.

Cost of Service

This study features a cost of service approach to capital costing. This approach has been developed by PEG Research to better approximate the way that capital cost is calculated in utility regulation. It is based on the assumption of straight line depreciation and the historic (a/k/a "book") valuation of plant. There are no capital gains from asset appreciation. Because of historical valuation, the capital price is a function not simply of the *current* construction price but, rather, of a weighted average of current and past values. This weighting, together with the exclusion of capital gains, stabilizes the capital price index substantially, thus reducing potential controversy surrounding the inflation differential in an ARP proceeding.

The intuition for taking a weighted average of past construction cost index values is that construction cost inflation drives rate base growth in a particular way. The cost of constructing plant that is, for example, two, four, and twenty years old is higher this year than was the cost of construction two, four, and twenty years ago last year. The weight for construction cost of a given vintage is larger the larger is its representation in the value of the rate base. Weights tend to be larger for more recent years than for earlier years because construction costs were higher and there has been less cumulative depreciation.

We have used our COS method in studies presented in testimony for Atlantic City Electric, Central Maine Power, Central Vermont Public Service, the Consumers' Coalition of Alberta, Delmarva Power, Fitchburg Gas & Electric, the Ontario Energy Board, Potomac Electric Power, Public Service of Colorado, Gaz Metro, and the Gaz

Metro Task Force. The productivity growth target in the current price cap plans of Ontario power distributors is based on productivity research that used COS capital costing. The methodology was also used to set an X factor for the revenue cap index of Central Vermont Public Service.

Note, additionally that Professor Alfred Kahn developed an approach to X factor calibration which is implicitly based on cost of service capital cost measurement. The results of Kahn's work found favor with the FERC in the establishment of an ARP for oil pipelines. Christensen Associates has occasionally used an approach to capital costing with COS attributes in its telecommunications productivity research.

Here is the mathematical derivation of our COS formulas. For each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Unit cost of plant installed in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of last year

N = Service life of utility plant

r_t = Rate of return (cost of funds)

WKS_t = Price of capital service

A few assumptions that are made for convenience in the derivation to follow:

(1) All kinds of plant have the same service life N.

(2) Full annual depreciation and opportunity cost are incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t.

(3) The ARM is not designed to recover changes in taxes.

Consider, now, that the non-tax cost of capital under cost of service regulation is the sum of depreciation and the opportunity cost paid out to bond and equity holders.

$$ck_t = ck_t^{\,opportunity} + ck_t^{\,depreciation}$$

Assuming straight line depreciation and book valuation of utility plant,

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} (1/N) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N)\cdot a_{t-s}}{xk_{t-1}}. \end{aligned} \quad \text{[A4]}$$

where, as per assumption 2 above,

$$xk_t = \sum_{s=0}^{N-1} xk_t^{t-s}. \quad \text{[A5]}$$

Under straight line depreciation we posit that in the interval $[(t-(N-1)),(t-1)]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \quad \text{[A6]}$$

Combining [A5] and [A6] we obtain a capital quantity index that is a perpetual inventory equation.

$$xk_t = \sum_{s=0}^{N-1} \frac{N-s}{N} \cdot a_{t-s}. \quad \text{[A7]}$$

The size of the addition in year t-s of the interval (t-1, t-N) can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \quad \text{[A8]}$$

Relations [A4] and [A8] together imply that

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_{t-1}} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \quad \text{[A9]} \\ &= xk_t \cdot WKS_t. \end{aligned}$$

Here

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}. \qquad [A10]$$

Relation [A10] reveals that the cost of capital under COS regulation can be decomposed into a capital price index and a capital quantity index. The capital service price in a given year reflects a weighted average of the capital asset prices in the N most recent years (including the current year). The weight for each year, t-s, is the estimated share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share will be larger the more recent the plant addition year and the larger were the plant additions made in that year. The average asset price rises over time as the price for each of the N years is replaced with the higher price for the following year. It will reflect inflation that occurred in numerous past years as well as current inflation. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[12]

Implementation Relations [A7] and [A10] were calculated for each sampled utility for two categories of assets: distribution plant and general plant. In these calculations, regional Handy-Whitman indexes of construction costs in the northeastern states were used as the asset price indexes.[13] In the distribution index the value of N was set at 44, our computation of the average service life of CMP distribution assets. The value of N for general plant was set at 12 years. The values for gross plant additions VK_{t-s}^{add} in the years 1965-2011 were drawn from the FERC Form 1. Values for earlier years were imputed using data on the net value of plant in 1964 and the construction cost index values for those years.

The calculation of [A10] requires, in addition, an estimate of the rate of return trend.[14] We employed a weighted average of the returns on four kinds of assets: an ROE

[12] Recall that the depreciation rate is constant under the geometric decay approach to capital costing.

[13] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

[14] This calculation was made solely for the purpose of measuring input price and productivity *trends* and does not prescribe an appropriate Rate of Return *level* for the Company in this

and the yields on Baa-rated corporate long bonds, ten-year treasury notes, and commercial paper. The ROE is the average of approved ROEs for a large sample of U.S. utilities. The ROE data were compiled by the Regulatory Research Associates unit of SNL Financial. For the bond yields, we computed 10 year averages of bond yields reported by Moodys Investor Services.[15] The weights for the three rates of return reflect the mix of funding sources employed recently by CMP.

A.2 Input Price Indexes

The growth rate of a summary input price index is calculated using a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

A.2.1 Index Form

The summary input price index used in this study is of Tornqvist form.[16] Its growth rate is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the subindex values in successive years. The average shares of each input in the applicable total cost of distributors during the two years are the weights.

A.2.2 Input Price Subindexes and Costs

Applicable total cost was divided for purposes of input price trend calculations into four input categories: distribution plant, general plant, labor services, and other O&M inputs. The cost of labor was defined for this purpose as the sum of salaries and wages and a sensible share of expenses for pensions and other employee benefits. The cost of other O&M inputs was defined as applicable O&M expenses net of these labor

proceeding. For example, the yield on ten year U.S. treasury notes is well below the yield that CMP would pay on bonds of similar duration.

[15] As used here, the term long bonds refers to debt securities with maturities of more than ten years. In calculating the trend in the rates of return, we used the trends in Baa corporate bonds and in 10 year treasury notes to measure the trends in the typical yields faced by power distributors for long- and short-term debt, respectively.

[16] For seminal discussions of this index form see Tornqvist (1936) and Theil (1965).

costs. The latter input category comprises a diverse set of inputs that includes materials, outsourced services, and leased equipment and real estate. The cost share for capital included taxes.

The price subindex for labor was the ratio of labor expenses to the labor quantity index. The price subindex for materials and services was calculated from detailed electric utility material and service ("M&S") price indexes prepared by Global Insight. The price subindexes for distribution and general plant were capital service price indexes. The capital price subindexes used in the trend comparisons did not include the term for taxes. Tables MNL-5 a and b and Figure MNL-3 present additional information on the power distribution input price trends of sampled utilities.

A.3 Input Quantity Indexes

The growth rate of a summary input quantity index is calculated by a formula. The formula involves subindexes measuring growth in the amounts of various kinds of inputs used. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

A.3.1 Index Form

The input quantity index used in this study is of Tornqvist form. The growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the quantities in successive years. The average shares of each input in the applicable total distributor cost of sampled utilities during these two years are the weights.

A.3.2 Input Quantity Subindexes and Costs

Applicable total cost was divided into the same four input categories used to develop the input price index: distribution plant, general plant, labor services, and other O&M inputs. The quantity subindex for labor was the ratio of salary and wage expenses to a labor price index for the northeast U.S.[17] The growth rate of the labor price index in this application

[17] Utilities no longer report on their FERC Form 1 the number of workers that they employ.

Table MNL-5a

Input Price Trends of Upper Northeast Power Distributors

	Input Price Growth Rates				Summary Input Price Trend
	Distribution Capital	General Capital	Labor O&M[1]	Materials & Services[2]	
2002	2.5%	3.2%	4.7%	1.8%	3.44%
2003	2.8%	3.9%	4.2%	2.8%	5.65%
2004	2.8%	3.4%	5.7%	3.9%	1.13%
2005	3.2%	2.5%	5.2%	4.5%	4.10%
2006	3.8%	2.9%	10.2%	4.7%	4.20%
2007	3.7%	3.7%	-4.3%	3.9%	3.95%
2008	3.5%	4.1%	3.1%	5.2%	3.01%
2009	3.4%	2.2%	3.1%	0.3%	2.83%
2010	3.5%	1.2%	5.5%	2.7%	3.55%
2011	3.2%	3.0%	3.4%	3.6%	3.60%
Average Annual Growth Rate 2002-2011	**3.24%**	**3.02%**	**4.08%**	**3.32%**	**3.55%**

[1] Labor trend index is calculated residually for each company as the ratio of labor O&M expenses to the O&M labor quantity index.

[2] M&S price index constructed from detailed price indexes for power distribution utility materials and services prepared by Global Insight for its Power Planner information service.

Table MNL-5b

Input Price Trends of Broad Northeast Power Distributors

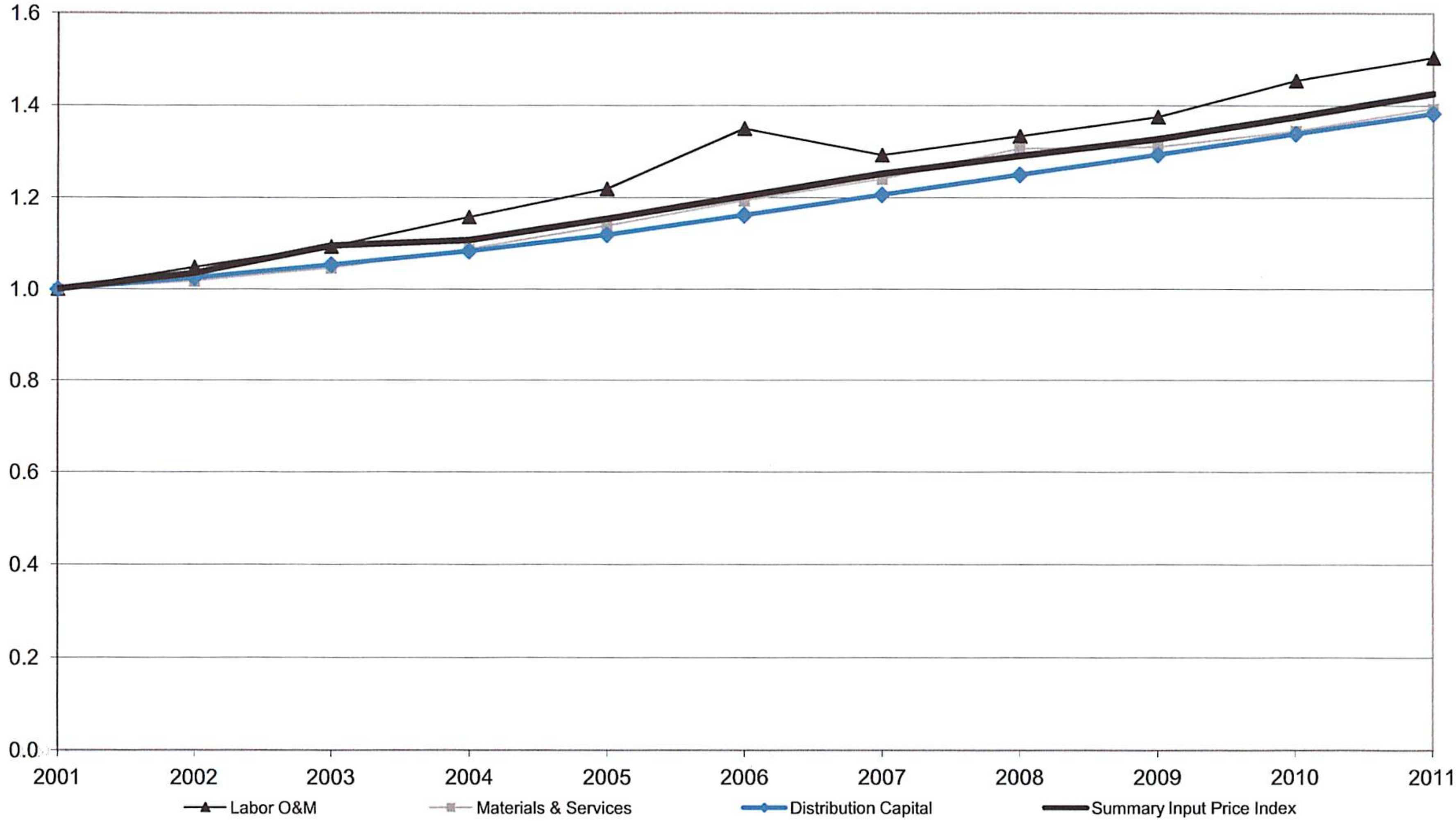
	Input Price Growth Rates				Summary Input Price Trend
	Distribution Capital	General Capital	Labor O&M[1]	Materials & Services[2]	
2002	2.4%	3.7%	4.7%	1.8%	3.17%
2003	2.6%	4.0%	4.1%	2.8%	4.19%
2004	2.6%	3.7%	5.7%	3.9%	1.61%
2005	3.4%	3.7%	5.1%	4.6%	3.98%
2006	3.7%	2.8%	10.1%	4.7%	3.93%
2007	3.6%	2.5%	-4.3%	3.9%	3.18%
2008	3.6%	3.5%	3.1%	5.2%	3.19%
2009	3.4%	2.3%	3.1%	0.2%	3.94%
2010	3.6%	1.2%	5.5%	2.7%	3.16%
2011	3.1%	2.9%	3.4%	3.6%	4.06%
Average Annual Growth Rate 2002-2011	**3.21%**	**3.02%**	**4.05%**	**3.32%**	**3.44%**

[1] Labor trend index is calculated residually for each company as the ratio of labor O&M expenses to the O&M labor quantity index.

[2] M&S price index constructed from detailed price indexes for power distribution utility materials and services prepared by Global Insight for its Power Planner information service.

Figure MNL-3

INPUT PRICE TRENDS OF SAMPLED UPPER NORTHEAST POWER DISTRIBUTORS



was calculated for most years as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector of the U.S. economy plus the difference between the growth rates of multi-sector ECIs for workers in the Northeast and in the nation as a whole.

The quantity subindex for other O&M inputs was the ratio of the expenses for these inputs to the material and services price index. The trend in the subindex is then the difference between the trends in the expenses and the M&S price index.

A.4 Econometric Capital Cost Model

In the econometric capital cost models the dependent variable is capital cost divided by the capital price index. The COS method was used to compute the numerator and denominator of this ratio. The model thus effectively explains the capital quantity of each utility and is useful for identifying utilities with capital stocks that are small given their operating scale and other external business conditions.

Substantive variables in the model were logged prior to estimation. The parameter estimates are thus also estimates of the corresponding cost elasticities. A feasible GLS procedure was used in parameter estimation which corrects for autocorrelation and heteroskedasticity.

The capital cost model was estimated using data from a sample that includes utilities outside the Northeast. A large sample improves the precision of econometric parameter estimates. The utilities included in the sample for econometric research are listed in Table MNL-6.

Table MNL-7 provides details of the econometric capital cost model that was used to calculate the K factor. Inspecting the results, it can be seen that the parameter estimates for the explanatory variables of the model are generally sensible and all are statistically significant at a high confidence level. Real capital cost increased with the delivery volume and the number of customers served. Capital cost was lower the greater was the percentage of system assets overhead, cooling degree days, heating degree days, and the number of gas customers served. The trend variable's parameter estimate suggests that capital cost declines by 0.47% per year for other reasons not specified in the

Table MNL-6

Companies in the Econometric Cost Model Sample

Alabama Power
Appalachian Power
Arizona Public Service
Atlantic City Electric
Avista
Baltimore Gas & Electric
Bangor Hydro-Electric
Carolina Power & Light
Central Hudson Gas & Electric
Central Maine Power
Central Vermont Public Service
Cleveland Electric Illuminating
Connecticut Light & Power
Dayton Power & Light
Duke Energy Carolinas
Duke Energy Indiana
Duke Energy Ohio
Duquesne Light
El Paso Electric
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Green Mountain Power
Gulf Power
Idaho Power
Indiana-Michigan Power
Indianapolis Power & Light
Jersey Central Power & Light
Kansas City Power & Light
Kansas Gas and Electric
Kentucky Power
Kentucky Utilities
Louisville Gas and Electric
Maine Public Service
Massachusetts Electric
Metropolitan Edison
Minnesota Power
Mississippi Power
Montana-Dakota Utilities
Narragansett Electric
Nevada Power
New York State Electric & Gas
Northern States Power
Nstar Electric
Ohio Edison
Oklahoma Gas and Electric
Orange and Rockland Utilities
Pacific Gas and Electric
PacifiCorp
Pennsylvania Electric
Pennsylvania Power
Potomac Electric Power
Public Service of Colorado
Public Service of Oklahoma
Public Service Electric and Gas
Puget Sound Energy
San Diego Gas & Electric
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas and Electric
Southwestern Public Service
Tampa Electric
Toledo Edison
Tucson Electric Power
United Illuminating
Virginia Electric and Power
West Penn Power
Western Massachusetts Electric
Western Resources
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Table MNL-7

Econometric Capital Cost Benchmarking Model

VARIABLE KEY

N = Number of Electric Customers
V = Retail Delivery Volume
OH = % of Distribution Plant Overhead
NG = Number of Gas Customers
CDD = Cooling Degree Days
HDD = Heating Degree Days
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.652	46.282	0.000
V	0.357	26.860	0.000
OH	-0.031	-2.289	0.022
NG	-0.008	-9.621	0.000
CDD	-0.022	-5.753	0.000
HDD	-0.026	-4.000	0.000
Trend	-0.005	-7.490	0.000
Constant	10.450	902.135	0.000
System Rbar-Squared	0.956		
Sample Period	2001-2011		
Number of Observations	814		

model. A 0.956 adjusted R^2 statistic suggests that the explanatory power of the model was high.

EXHIBIT MNL-2

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