IGUA #1

INTERROGATORY

Reference: Pacific Economics Group ("PEG") Report, Executive Summary, pp. (i) to (vii) inclusive

Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

The evidence indicates that PEG is the advisor to Board Staff on Incentive Regulation ("IR") issues and that PEG's mandate is defined by Directives from Board Staff. The evidence refers to Board Staff January 5, 2007, Discussion Paper which is found in Union's evidence at Ex.B, Tab 1, Appendix A. The Board Staff Discussion Paper indicates that PEG was its adviser at the time the Discussion Paper was prepared. The Discussion Paper addresses many topics on the Issues List attached as Appendix A to Procedural Order No. 4. IGUA wishes to determine the extent to which the contents of the Board Staff Discussion Paper reflects advice and opinions PEG provided to Board Staff. In this context, please provide PEG's responses to the following questions:

a) When did PEG first become the adviser to Board Staff with respect to IR issues?

b) Did PEG express opinions to Board Staff which are reflected in the opinions described in the Discussion Paper which are attributed to Board Staff?

c) Please describe the extent to which PEG participated in the drafting of the Discussion Paper.

d) Using the list of each of the items in the Table of Contents of the Board Staff Discussion Paper found in Union's evidence at Ex.B, Tab 1, Appendix A and for each of the items and sub-items in Topic 2 "Underlying Principles", Topic 3 "Incentive Regulation Plan Design" and Topic 4 "Other Issues", provide PEG's opinion on each of the matters discussed and a brief description of PEG's rationale for its opinions on each of these subject matter items.

e) Using the List of Questions contained in the Board's Issues List found at Appendix A to Procedural Order No. 4, please provide PEG's answers to each of the questions asked in items 1 to 14 inclusive, including a brief description of PEG's rationale for each response.

RESPONSE

a) The Board and PEG signed the contract agreement on May 11, 2006.

b) Neither PEG nor Board staff filed the Board Staff Discussion Paper in this proceeding. Neither PEG nor Board staff will be relying on the Discussion Paper in this proceeding. Questions relating to PEG's involvement in drafting the Discussion Paper are therefore not relevant to this proceeding.

c) As stated on page 14 of the Staff Discussion Paper, footnote 5, Section 3.3 of the Paper (X Factor) was written by PEG. Neither PEG nor Board staff filed the Board Staff Discussion Paper in this proceeding. Neither PEG nor Board staff will be relying on the Discussion Paper in this proceeding. Questions relating to PEG's involvement in drafting the Discussion Paper are therefore not relevant to this proceeding. In addition, this question asks for material covered by privilege, which privilege has not been waived by Board staff.

d) It is too early in the process to answer all these questions.

IGUA #2

INTERROGATORY

Ref: PEG Report, Executive Summary, pp. (iii) to (vii) inclusive

Issue Number: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

PEG's evidence contains summary tables of the Indexes computed by PEG for EGD and Union. Union's evidence at Ex.B, Tab 1, page 8 contains a Table summarizing Union's price cap plan proposal. EGD's evidence at Ex.B, Tab 1, Schedule 1, pp.1 to 3 contains a summary description of its proposal. IGUA wishes to understand the differences between the IR regimes being proposed by Union and EGD and PEG's recommendations for each utility. In this context, please provide responses to the following questions:

a) Using Union's Table 1 as the point of departure, please revise the Table as required to show how Union's summary would differ if the Board accepted PEG's recommendations for Union.

b) Does PEG recommend a Price Cap rather than a Revenue Cap for EGD?

- If the answer is yes, then please briefly explain the rationale for PEG's response;

- If the answer is no, then please briefly explain the rationale for PEG's response and include therein an explanation of why, in PEG's view, the Board should consider approving IR regimes for Union and EGD which materially differ.

c) Please provide an exhibit which summarizes PEG's understanding of EGD's IR proposal using the same parameter topic headings Union uses in its Table 1 and then provide a revision to that summary table to show how EGD's proposal would differ if the Board accepted PEG's recommendations for EGD.

RESPONSE

Witness: Mark Lowry

a) Please see the Executive Summary to our report for tables that provide a point of comparison to the union and Enbridge proposals. If the Board accepted PEG's recommendations for Union, the X factor would be 0.52 instead of the 0.02 discussed in Union’s filing.

b) No. We believe that the proposed revenue per customer cap is a reasonable alternative to a price cap for EGD. Our reasons for this opinion include the following.

- Revenue caps effectively address the financial hardships that can result for a gas utility from declining average use.
- Revenue caps can materially reduce the operating risk that results from weather volatility.
- A revenue per customer approach to revenue cap indexing is reasonable if implemented correctly. There is precedent for this approach in the approved revenue per customer cap plan of Southern California Edison. Dr. Lowry of PEG was a witness for Edison in that proceeding and testified for both Edison and San Diego Gas & Electric in support of a similar approach in a subsequent proceeding.
- A salient disadvantage of revenue caps is the weak incentives that they provide for effective marketing of utility services. This is less of a problem for Enbridge than it is for Union since the large volume retail and wholesale customers that benefit most from marketing flexibility are a substantially smaller part of its business.
- The businesses of the two companies are different enough for consideration to be paid to separate IR approaches for them. A revenue per customer cap can be developed using the same research and principles as apply to the price cap plan that PEG has detailed.

c) PEG’s and EGD proposals are not comparable because:

- PEG calculated a revenue cap, not a revenue cap per customer as proposed by EGD

- In terms of Y factors, PEG’s proposals for both companies were calculated with the underlying assumption that no capital expenditure would be treated as a Y factor. PEG’s proposed X factor would be higher if most of the capital expenditure would be considered a Y factor.

Witness: Mark Lowry

IGUA #3

INTERROGATORY

Ref: PEG Report, Executive Summary, pp. (i) to (vii) inclusive, Board Staff Discussion Paper, Union evidence Ex.B, Tab 1, Appendix A

Issue Number: 1.2, 5.1 and 6.1
Issue: 1.2 What is the method for incentive regulation that the Board should approve for each utility?
5.1 What are the Y factors that should be included in the IR plan?
6.1 What are the criteria for establishing Z factors that should be included in the IR plan?

The evidence indicates that the IR Regime which PEG supports contemplates that a number of components of the regulated revenue requirements of Union and EGD will continue to be subject to some form of continuing Cost of Service ("COS") regulation for the duration of any IR plan the Board might approve for each of these utilities. In this context, IGUA regards Y factors, including Deferral Accounts, and Z factors as continuing COS features of rate regulation. IGUA would like to obtain PEG's analysis of the extent to which the regulated revenue requirements of Union and EGD will continue to be subject to some form of continuing COS regulation over the duration of any IR plan the Board might approve for each utility. To this end, please provide, in separate schedules for Union and EGD, the following:

(a) PEG's understanding of the total base year regulated revenue requirement for Union and EGD;

(b) PEG's understanding of the total base year delivery-related regulated revenue requirement for Union and EGD;

(c) PEG's segregation of the total base year regulated revenue requirement for Union and EGD to be provided in response to question (a) between the following broad categories:

- Cost of gas, operations and maintenance expenses,
- Depreciation,
- Property taxes,
- Capital taxes,

- Return segregated as follows:
  - Equity return
  - Cost of debt
  - Income taxes

(d) Within each of these broad categories, list and provide PEG's quantification of any item of COS which, in whole or in part, falls within the categories of Y factors, including Deferral Accounts, and Z factors proposed by Union and EGD.

(e) Using information to be provided in response to the previous questions, please provide PEG's estimate of the following:

(i) the proportion of the total regulated revenue requirement of Union and EGD which will not be subject to some form of continuing COS treatment under the IR plans proposed by Union and EGD;

(ii) the proportion of the delivery-related revenue requirement of Union and EGD which will not be subject to some form of continuing COS treatment under the IR plans proposed by Union and EGD.

RESPONSE

PEG is not qualified to answer this question. The question is better directed to Union and Enbridge. With regard the segregation of costs, we believe that all of the non-gas costs listed in subpart (b) can potentially be covered by the rate escalation index. Companies should be able to make a Z factor filing for material changes in tax rates that are not reflected in the inflation measure. Thus, some or all taxes could in principle be Y factored as an alternative.

Witness: Mark Lowry

IGUA #8

INTERROGATORY

Ref: PEG Report, Executive Summary, pp. 2 and 15 to 17
Issue Nos.: 4.1, 4.2 and 4.3
Issue:
4.1 Is it appropriate to include the impact of changes in average use in the annual adjustment?
4.2 How should the impact of changes in average use be calculate?
4.3 If so, how should the impact of changes in average use be applied (e.g., to all customer rate classes equally, should it be differentiated by customer rate classes or some other manner)?

The evidence discusses the average use factor as an adjustment to the X factor. The IR plans which Union and EGD propose contemplate that Demand Side Management ("DSM") matters will be a Y factor adjustment. The evidence also indicates that DSM measures and declines in average use are inter-related. In this context, please provide PEG's response to the following questions:

(a) Is there any reason why declines in average use could not be included within the ambit of the Board's consideration of matters pertaining to a Y factor for DSM or as a separate average use Y factor?

(b) Please revise the Tables in the Executive Summary of PEG's evidence at (iii), (iv) and (v) to exclude the average use factor as an adjustment to the X factor.

RESPONSE

(a) No

(b) The attached file labeled "IGUA Q8 attachment. PDF" provides the revised tables in the Executive Summary of PEG's evidence at (iii) and (v). The update of Table iv would require significant new research. PEG cannot provide the results of this update within the timelines of the interrogatories' responses. However PEG anticipates that results of this update will be available prior to the commencement of ADR.

Witness: Mark Lowry

reasonable, and can place incentive regulation of Ontario's gas utilities on a solid foundation of economic reasoning and empirical research.

Key Results

The following table details our proposals for the X factors of the summary PCIs. It also provides, in italics, a notion of the likely growth in these PCIs during the IR plan. This projection requires an assumption regarding GDPIPI growth, and we use for this purpose the recent historical trend. The growth in the *actual* PCI would reflect the growth in the actual GDPIPI for final domestic demand during the IR plan period. The table presents, finally, indexes computed by PEG of the trend in each company's rates during the 2000-2005 period.

Summary Price Cap Indexes

	Enbridge	Union
Productivity Differential	0.89	0.52
Input Price Differential	0.27	0.22
Stretch Factor	0.50	0.50
X Factor [A = sum of above]	**1.66**	**1.24**
Recent GDPIPI Trend [B]	*1.86*	*1.86*
PCI *[B-A]*	***0.20***	***0.62***
Summary Rate Trends	***1.37***	***0.87***

It can be seen that, for both companies, PCI growth would be materially slower than the growth in the GDPIPI. Ontario gas consumers would, in other words, experience growth in rates for gas utility services that are below the general inflation in the prices of final goods and services in Canada. The higher X for Enbridge is chiefly due to its greater opportunities to realize scale economies. The notional PCI trend is, for each company, quite similar to the overall trend in their actual rates during the 2000-2005 period.

Here are some details of our recommendations for the PCIs for individual service groups. Separate PCIs have been designed for each rate class that includes residential service. The rates for all other services would be subject to common but company specific

Revenue Cap Indexes

	Enbridge	Union
Productivity Differential [A]	0.89	0.52
Input Price Differential [B]	0.27	0.22
Stretch Factor [C]	0.50	0.50
X Factor^{RCI} [D=A+B+C]	**1.66**	**1.24**
Output Growth [E]	**2.83**	**1.92**
GDPIPI [F]	*1.86*	*1.86*
Indicated RCI Growth [F-D+E]	***3.03***	***2.54***[3]

It can be seen that the RCIs grow more rapidly than the corresponding PCIs. This is due chiefly to the fact that an RCI is designed to compensate the utility for its *cost* trend rather than its *unit* cost trend.

Input Price Differential

We compared the input price trends of Ontario gas utilities to that of Canada's economy using both capital costing methods. We chose the 1998-2005 period as the one ending in 2005 that was well suited for calculating the IPD using COS capital costing. We found that the appropriate input price differentials for Enbridge and Union were 0.27% and 0.22% respectively. This is to say that the trend in the economy's input prices was a little more rapid than the trend in the industry's.

Productivity Differential

We compared the productivity trends of Enbridge and Union (*i.e.*, company specific TFP trends) to the trends of US gas utilities in an effort to ascertain appropriate TFP targets. The chosen targets were compared to the multifactor productivity ("MFP") trends of the Canadian private business sector to calculate the PDs for each company. Under the COS approach to capital costing the annual TFP growth of Enbridge and Union averaged 0.71% and 1.87% respectively. The productivity of Enbridge in the use of operating and maintenance ("O&M") inputs slowed materially in 2003 upon the expiration of the multi-

[3] The actual trend in the index would depend, once again, on actual GDPIPI FDD growth during the plan.

IGUA #10

INTERROGATORY

Ref: PEG Report, Executive Summary, page (iv), pp. 64 to 67
Issue Nos.: 3.1 and 3.2
Issue: 3.1 How should the X factor be determined?
3.2 What are the appropriate components of an X factor?

The evidence indicates that the Price Cap Index for EGD's non-residential customer classes would be 0.32% and for Union's non-residential customers would be 0.08%, and that the Price Cap Index for residential service groups will be higher when a negative average use adjustment factor is included in the X factor. Please provide responses to the following questions with respect to this evidence:

a) Are these service group PCIs for the non-residential customers of Union and EGD shown in Table (iv) of the PEG Report indicative of the Price Caps that would apply to determine the 2008 Rates for EGD and Union? If the answer is no, then please indicate the year for which these Price Cap Indeces would be applicable. For example, are they the Price Caps that would apply to determine Union and EGD rates for 2007, using a 2006 revenue requirements and rates as the base?

b) What do the Price Cap Indeces for the residential rate classes become if the average use adjustment factor is treated as a Y factor, rather than as an adjustment which reduces the X factor?

c) What are the statistical confidence levels for the service group Price Cap Indeces which PEG recommends?

d) What other regulators have adopted service group Price Cap Indeces in the IR plans for the utilities they regulate?

RESPONSE

a) PEG developed the proposed PCIs under the assumption that they would apply to determine the 2008 Rates for EGD and Union. However PEG is not certain when the Board plans to implement the proposed PCIs.

Witness: Mark Lowry

b) We believe that the X factors for residential services will be substantially higher and PCI growth substantially lower. Results of the research that will be undertaken to respond Exhibit R-PEG Tab5 Schedule 8 b) will further clarify this answer.

c) Statistical confidence levels for the service group Price Cap Indices were not calculated as part of this research.

d) PEG has never undertaken a comprehensive review of this issue. However, we believe that service-group specific PCIs are often found in price cap plans for telecom utilities. These commonly take the form of rate freezes on basic services to residential customers

IGUA #12

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 1, Schedule 1, pp. 3-22, Ex.B, Tab 3, Schedules 1, 2 and 3

Issue No.: 1.2

Issue: What is the method for incentive regulation that the Board should approve for each utility?

There are a number of criticisms of PEG's Report contained in EGD's evidence. Please provide responses to the following questions with respect to EGD's criticisms of PEG's Report:

(a) Please have PEG provide a list of each of the criticisms which EGD makes of its report and a summary of PEG's response to each of those criticisms.

RESPONSE

Please see the attached document, "IGUA Question 12: PEG Objections to Enbridge Testimony".

Witness: Mark Lowry

IGUA Question 12:

PEG Objections to Enbridge's Testimony

Pacific Economics Group, LLC

Economic and Litigation Consulting

IGUA QUESTION 12:

PEG OBJECTIONS TO

ENBRIDGE'S TESTIMONY

Mark Lowry
Managing Partner

PACIFIC ECONOMICS GROUP

22 East Mifflin, Suite 302
Madison, Wisconsin USA 53703
608.257.1522   608.257.1540 Fax

Table of Contents

1. Introduction

This response groups into one convenient location many of the numerous objections that we have to the testimony of Enbridge Gas Distribution witnesses concerning our research. We will provide additional remarks at the upcoming technical conference.

2. Regulatory Policy Issues

Two large policy issues related to X factor design are largely independent of the details of PEG's TFP and econometric research. The first is adjusting the X factor for developments that EGDI claims are relevant yet have not been considered by PEG. The second is the use of a Y factor to recover extensive costs.

2.1 Proposed Adjustments to the X Factor

Enbridge witnesses propose adjustments to the X factor to reflect factors that are likely to increase the Company's unit cost and are allegedly not considered in PEG's analysis. Adjustments were emphasized for the Company's expected cast iron capital replacement expenditures and for the *expected* decline in average gas use per customer (AUPC). PEG assesses the merits of each of these adjustments below.

2.1.1 Adjusting the X Factor for Cast Iron Replacement Expenditures

All Enbridge witnesses proposed adjusting the X factor for the Company's expected increase in cast iron capital replacement expenditures. Dr. Carpenter went so far as to claim that it would be "patently unreasonable" to reject an adjustment to Enbridge's X factor because of this projected investment program. PEG disagrees and believes it is far more reasonable, and better regulatory policy, **not** to adjust the X factor for Enbridge's cast iron replacement program over the term of the next PBR plan. This is true for at least four reasons:

1. *Adjusting the X factor in advance can create poor performance incentives*

The amount of money that Enbridge spends on cast iron replacement over the term of the PBR plan cannot be known at present, but it is subject to Company discretion. In the absence of a countervailing incentive, if Enbridge was granted an adjustment to its X factor to reflect the costs of a speculative replacement program, it would have an incentive to forecast high replacement expenditures *ex ante* yet keep its actual spending below forecast levels. This type of behavior would maximize the Company's profits and could be justified *ex post* in many ways that would be difficult for the OEB to verify, such as claiming that the Company achieved more efficiencies in replacement spending than it anticipated. These "gaming" incentives could be mitigated by having countervailing mechanisms that penalize the Company for not spending all that it originally forecast, but such mechanisms also create poor incentives since they eliminate utilities' incentives to undertake capital replacement programs as efficiently as possible.

There is ample evidence supporting PEG's concern that inappropriate incentives are likely to arise if EDGI's X factor is adjusted *ex ante* to reflect projected capital expenditures. Most importantly, PBR plans for British energy utilities have set X factors on the basis of companies' projected expenditures over the term of their indexing plans, including projected capital expenditures. Incentive problems related to forecast gaming and subsequent capital "underspend" have bedeviled British regulation from the beginning. In the most recent (2005) price controls that were established for power distributors, the UK energy network regulator (the Office of Gas and Electricity Markets, or Ofgem) eventually dealt with these poor incentive properties by establishing a complex "sliding scale mechanism" that determined each company's allowed capital expenditures based on its forecasts relative to benchmark forecasts. Overall, the British experience suggests that linking X factors to projected capital expenditures introduces a host of undesirable incentive problems and encourages counterproductive behavior. Addressing these problems requires greater regulatory intervention and/or far more complex regulatory mechanisms than have been considered to date in Ontario incentive regulation.

2. *No Foundation* EGDI's claims that its cast iron program is not reflected in PEG's analysis are also unfounded. There has, in fact, been a significant amount of cast iron replacement in the US gas distribution industry in recent years, and these replacement expenditures are reflected in PEG's baseline estimate for industry TFP

trends. It is not clear that the volume of capital replacement that Enbridge anticipates for the future differs from the pattern of capital replacement that is already reflected in the Company's projected X factor. EGDI should present data to support its claim that the Company's pattern of future cast iron replacement expenditures are materially different from the cast iron replacement spending that has been undertaken by the US gas distribution industry rather than simply asserting, without evidence, that this difference exists.

3. *Difficulty of Determining the Quantitative Impact of the Adjustment* One method for establishing an X factor for the plan is to regress the growth of TFP on some measure of change in cast iron using the US sample data. PEG did this using a two-tailed test of statistical significance and the growth in the percentage of lines that are not cast iron as an explanatory variable. We reported in June using a two-tailed test of statistical significance that the change in the cast iron percentage did not have a statistically significant impact on TFP growth. Even if an adjustment was justified, it is not at all clear what magnitude is appropriate for a given capital replacement program.

It is also possible that the relationship between cast iron expenditures and the X factor could vary by firm; for example, utilities operating in areas of high labor costs or extreme population densities may have higher costs for undertaking a given volume of cast iron replacement. Any practical proposal for adjusting the X factor to reflect capital replacement expenditures would have to confront these quantification issues, which are by no means straightforward to resolve.

4. *Implementation and Administrative Burdens* As demonstrated above, adjusting the X factor for cast iron replacement raises a number of complex measurement and implementation issues that EGDI fails to acknowledge, let along provide any practical guidance or empirical evidence for resolving. More information is needed immediately to establish that an X factor adjustment is even needed for Enbridge's capital investment spending. The link between this spending and the magnitude of the X factor adjustment would also have to be quantified. Enbridge would also have to demonstrate, both now and at the time of rate rebasing, that there was no double counting

of the costs of capital replacement. A sliding scale mechanism or similar provisions to ensure truthful capital spending forecasts would also be complex to design and administer and also necessarily involve detailed capital expenditure benchmarks for each distributor. All of these factors greatly complicate and add costs to the PBR regime.

Given these reasons, PEG believes it is far more reasonable not to adjust the X factor for Enbridge's capital expenditures over the term of the plan. PEG's approach is more likely to be consistent with creating appropriate performance incentives, prevent inadvertent double counting of revenue adjustments, and reduce regulatory costs and burdens.

2.1.2 Adjusting the X Factor for Declining Use Per Customer

EGDI has also proposed that the X factor be adjusted to reflect declining average gas use per customer (AUPC). Again, PEG believes that this would not be appropriate. Most of the reasons discussed above for why it is not appropriate to adjust X *ex ante* because of projected capital expenditure replacement expenditures also apply to *ex ante* X factor adjustments for declining AUPC. In particular:

1. *Bad incentive properties* EGDI would have incentives to game its AUPC forecasts just as it would to game its capital replacement expenditure forecasts. The Company would benefit financially from achieving the lowest possible X, which in turn depends on the largest possible downward adjustment in X due to revenue losses from projected declining AUPC.

2. *No Foundation* It is well-known that AUPC has been declining for residential and commercial customers for decades. Indeed, it is well-documented that volumes for US residential and commercial customers have been declining for over 25 years because of factors including greater energy conservation and the use of better materials and more energy efficient appliances in new construction. One study by the American Gas Association (AGA) estimates that gas consumption per household declined by 22% from 1980 to 2001 in weather-normalized

terms, while a more recent AGA study shows that this decline has accelerated, with gas usage per customer declining an additional 13% between 2000 and 2006.[1] This represents a substantial decline in AUPC in recent years, which would be reflected in PEG's estimated TFP trends. EGDI has presented no evidence to substantiate its claim that its delivery volumes over the term of the PBR decline would decline at a more rapid rate than the already rapid rates of decline that are currently reflected n their proposed X factor.

3. *Double Counting* Under a revenue cap mechanism, declines in AUPC are dealt with through balancing accounts and subsequent adjustments to true-up actual to allowed revenues. If the X factor is adjusted *ex ante* and there is an additional adjustment for declining AUPC, there will be a double counting of revenue losses due to declining consumption.

4. *Implementation and Administrative Burdens* Again, adjusting the X factor *ex ante* because of declining AUPC raises implementation and administrative burdens. Additional costs would be incurred to evaluate the truthfulness of EGDI forecasts, create countervailing mechanisms to encourage truthful projections, and determine the need and magnitude of an appropriate X factor adjustment. These additional costs would not be incurred under PEG's approach.

For these reasons, we also believe it is not appropriate to adjust the X factor for Enbridge's projected decline in AUPC over the term of the plan.

2.2 Y Factor

Enbridge proposes that, absent appropriate X factor adjustments, the Company be allowed to Y factor numerous categories of capital expenditures.

PEG Response

[1] For information on the decline since 1980, see the American Gas Association (2004). The more recent study is by Joutz and Trost (2007).

The Y factoring of a sizable part of the Company's capital expenditures can create a serious imbalance between the incentives for short term and long term cost containment. There is an incentive to undertake excessive replacement capex that results in suboptimally *small* use of labor and other kinds of operation and maintenance inputs.

PEG notes also that the Y factoring of any sizable cost component would require a recalculation of the TFP target for Enbridge. That is because the current target is based on research in which the full amount of capex is counted. Capital is the fastest growing input category for most gas distributors and materially slows TFP growth. A recalculated X factor would *rise* materially. This adjustment would be difficult to do precisely since the available capex data for US utilities isn't highly detailed.

2.3 *The Stretch Factor*

2.3.1 Need for a Stretch Factor

1. Bernstein states (p. 22) that "A stretch factor arises when regulated firms shift from an earnings-based regime to an incentive-based regime, but in such cases prices are set only at the outset of the IR regime, and are never again rebased. *Since future prices will be rebased at the end of the forthcoming IR period, this procedure transfers productivity improvements to consumers and eviscerates the rationale for a stretch factor* [italics added]."

PEG Response

Bernstein's assertion at p. 22 is glaringly at odds with the precedents for stretch factors in energy utility regulation. The fact of the matter is that *almost every* IR plan for *energy* utilities that features a rate adjustment mechanism with a stretch factor has ended in a rate case. The only exceptions are the plans that *haven't ended yet*. Dr. Bernstein, with his telecom background, can perhaps be forgiven for this embarrassing misstatement.

It is also noteworthy that two of Dr. Bernstein's published articles support stretch factors as a component of the overall X factor without adding the caveat about rebasing that serves the interest of his client. For example, Bernstein and Sappington (1999)[2] say

> "When a new regulatory regime and/or competitive pressures can reasonably be expected to motivate the regulated firm to enhance its realized productivity growth rate, historic growth rates can understate the most appropriate X factor to impose on the regulated firm. To account for this fact, the basic X factor in price cap regulation plans can be (and often is) augmented by what is called a consumer productivity dividend (CPD) or a stretch factor. In principle, a CPD should reflect the best estimate of the increase in the productivity growth in the regulated sector that will be induced by the enhanced incentives in the regulated industry."

Bernstein (2000) has also written[3]

> "When price cap regulation replaces rate of return regulation in an industry, firms can often be expected to achieve a higher productivity growth rate in the future than they have in the past. Therefore, it can be appropriate to augment *any* (emphasis added) historically-based estimate of the X factor with what is called a *consumer productivity dividend* (CPD). In principle, a CPD should reflect the best estimate of the increase in the productivity growth in the regulated sector that will be induced by the enhanced incentives in the regulated industry."

Please note also that Dr. Bernstein appears to advocate a stretch factor that captures the *entirety* of the expected productivity acceleration and not *half* of it as PEG does.

2. Bernstein states at 4 that "rebasing ensures that the consumer benefits from the productivity improvements, since the new prices they face encompass the firm's superior productivity performance." Lister argues (p. 29) that "perhaps the strongest reason to ignore an additional consumer dividend is that the largest customer benefit is derived through the rebasing mechanism and not through the stretch factor."

PEG Response

These statements are at odds with common sense and the company's own experience. One reason is that good performance depends in part on the pursuit of *short term* and

---

[2] Bernstein, Jeffrey I. and Sappington, David E.M. (1999), "Setting the X Factor in Price-Cap Regulation Plans", *Journal of Regulatory Economics*, 20 page 19.

[3] Bernstein, Jeffrey I. (2000), "Price Cap Regulation and Productivity Growth", *Telecommunications Policy*, 24 page 5.

unsustainable opportunities for performance gains (*e.g.* low prices on inputs) as well as on long term performance gains. Rebasing alone will not effectively share the short term benefits. Of equal or greater importance is the fact that absent innovative rebasing mechanisms, companies may have incentives to relax cost vigilance in the late years of a PBR plan, to postpone certain expenditures, and to exaggerate needed forward test year increases. These strategies can markedly reduce the benefits customers receive from IR plans at rebasing. Enbridge customers know this better than most since the Company's O&M expenses surged at the conclusion of its targeted PBR plan.

3. In paragraph 70 (page 29) of his testimony, Mr. Lister claims that the Commission Staff in Massachusetts supported the elimination of the consumer dividend in the PBR plan approved for Boston Gas in 2003, citing a passage in the Initial Brief of the Massachusetts Division of Energy Resources (DOER). However, the DOER is **not** part of the Staff of the Massachusetts Department of Telecommunications and Energy (aka the Department of Public Utilities). The DOER is, rather, a Massachusetts State agency that is entirely independent of the DTE and was acting as an outside intervenor in the Boston Gas proceeding. The DOER positions in the Boston Gas case in no way reflected those of the DTE or DTE Staff. On the contrary, the DTE rejected DOER's price cap proposal for Boston Gas in its entirety, concluding that it was "problematic" and had "no record support" (Final Order, Docket D.T.E. 03-40, October 31, 2003, p. 472). It is also clear from the record in D.T.E. 03-40 that DTE approved a consumer dividend of 0.3% for the Boston Gas PBR plan and carefully considered other values for this parameter before making its decision. A noteworthy counter-proposal came from the Massachusetts Attorney General, which recommended a consumer dividend of one percent. The DTE ultimately rejected this proposal as well, saying

> The Attorney General did not provide any empirical support for his proposal. We agree with the Attorney General that a higher consumer dividend will result in greater benefit for customers, and a greater incentive for Boston Gas to achieve further cost reductions and productivity gains under the PBR plan. However….the Department's decision is constrained by the requirement of substantial evidence and thus must be tethered to the record. The Department, therefore, rejects the Attorney General's tempting but unsupported proposal. (D.T.E. 03-40, pp.

486-487)

This position expressed by the DTE is close to the opposite of what Lister suggests. Far from wanting to eliminate the consumer dividend, the DTE generally favored larger as opposed to smaller consumer dividends. It found the Attorney General's one percent consumer dividend proposal "tempting" but ultimately unacceptable because of the lack of a supporting evidentiary record [PEG has provided the necessary evidentiary record in this proceeding with its incentive power model and its calculation of the industry norm]. In sum, there is no evidence anywhere in the Boston Gas proceeding that neither the DTE nor DTE Staff ever supported eliminating the consumer dividend, and Mr. Lister's conclusion on this point is founded on confusion rather than fact.[4]

2.3.2 Incentive Effects

1. Lister argues (pp. 21-23) that stretch factors *weaken* incentives for better operating performance.

<u>PEG Response</u>

Stretch factors are widely recognized to be one approach to sharing IR performance gains that does *not* weaken performance incentives. Incentives depend only on whether the benefits that are shared with customers are linked, either currently or prospectively, to the efficiency gains a firm actually achieves under a PBR plan. If a benefit sharing mechanism does not create a direct link between the amount of benefits that are shared and a firm's achieved efficiency gains, then the benefit sharing device is said to be *external* to the firm and its actions. This is analogous to the fact that industry input price and TFP trends are said to be external to the utility in question because, in all of these instances, the values that are taken for parameters that are used to adjust rates cannot be affected by the firm's own actions. Pre-established stretch factors are *external*

[4] It may also be recognized that, on pp. 486-87 in D.T.E. 03-40, the D.T.E. clearly states that it believes utilities' performance incentives will be increased rather than diminished by having higher values for consumer dividends. PEG does not agree with this view, and indeed our incentive power research concludes that incentives are not impacted at all by the values of consumer dividends that are chosen at the outset of PBR plans. However, it is also worth noting that the Department's conclusion in D.T.E. 03-40 runs counter to Mr. Lister's views that consumer dividends necessarily reduce incentives, which also tends to undermine rather than support the conclusions that he draws from this precedent.

benefit sharing devices. The values of benefits that are shared with customers through these measures are set in advance of the plan's operations and hence must be external to, and independent of, the firm's actual performance gains under the plan.

PEG's published work has routinely pointed out the positive incentive effects of consumer dividends as benefit-sharing devices. For example, in our White Paper for the Edison Electric Institute titled *Price Cap Regulation for Power Distribution*, PEG says "an important advantage of stretch factors is that their values can be assigned independent of a company's unit cost trend, so they do not compromise performance incentives or raise cross subsidy issues."[5]

Lister's crude numerical analysis is obviously flawed as a means for assessing stretch factor incentives. A real stretch factor does not in fact take *any* share of the cost savings in the illustrative example. The company keeps the full cost saving until the expiration of the plan. To say otherwise is like saying that a Hamilton steelmaker facing sagging prices for its product has weakened incentives to cut cost.

4. In paragraph 52 (page 23) of his testimony, Mr. Lister says that in "the recent PEG presentation <u>Comparing AltReg Options</u> (June 2007), PEG states that 'companies pursue efficiency to profit, transferring efficiency gains to customers reduces incentives to undertake actions that improve efficiency.' The consumer dividend reduces the Company's incentives to improve efficiency."

<u>PEG Response</u>

This quotation is drawn from a presentation by Dr. Kaufmann of PEG at a Boston conference. The last sentence in this passage does not come from PEG, although a reasonable reader might conclude that Mr. Lister believes this conclusion is either contained elsewhere, or flows logically, from the aforementioned PEG presentation.

It is true that the passage Mr. Lister cites does appear on the second slide on PEG's <u>Comparing AltReg Options</u> presentation in Boston in June 2007. This slide also says

[5] Kaufmann, L. and M.N. Lowry (2000), *Price Cap Regulation of Power Distribution*, p. 33.

”there is usually a tradeoff between creating incentives to perform efficiently and transferring efficiency gains to customers as lower prices.” These points are followed up on the following slide (Slide 3), which says

Policymakers try to balance goals of incentives and customer benefit

Can be done many ways

i. Change term of incentive regulation (e.g. CPI-s) plan

ii. Add earnings sharing mechanism (ESM) plan

iii. Transfer all efficiency gains to customers at end of plan

iv. Transfer some efficiency gains to customers at end of plan

However, nowhere in this presentation does it say that the value of the *stretch factor* will affect the “tradeoff between creating incentives to perform efficiently and transferring efficiency gains to customers.” Indeed, this point is intentionally excluded from the list of ways that policymakers try to balance these goals. PEG therefore believes that a full examination of the entire presentation that Mr. Lister cites (attached as IGUA 12 Comparing AltReg Options.ppt to this response) as well as PEG’s long-standing position on these issues, undermines rather than supports Mr. Lister’s conclusions.

2.3.3 Relationship between Consumer Dividend and DSM Objectives

Lister argues that consumer dividends make it harder for utilities to achieve their DSM and energy conservation objectives since they tend to lower prices and lower prices encourage more consumption.

PEG Response

This is silly. It is critical not to pursue enhanced end-use efficiency as if this goal exists in a vacuum. OEB objectives also include encouraging least-cost energy supply and delivery, consistent with maintaining safe, reliable service. The promotion of demand response should not be implemented in a manner that makes it more difficult for utilities to achieve other productive efficiencies, and that exacerbates upward pressures on prices, as Mr. Lister apparently advocates. This will immediately reduce customer welfare and could have longer-term negative consequences if, for example, it reduces the competitiveness of the Ontario economy and causes energy price-sensitive customers to close down plants, switch operations to other Provinces or US States, or otherwise reduce their local economic activity. The loss of price-sensitive energy loads would reduce utilities' ability to spread their fixed costs and thereby contribute to even further upward price pressures. PEG is not trying to be overly alarmist regarding these dangers, but it is important for the OEB to keep this bigger picture in mind. Social benefit will be promoted by encouraging efficiency across the entire utility value chain, which implies that regulatory policy should be balanced and comprehensive and not focus on a single objective to the exclusion, and possible frustration, of others.

3. TFP Indexes

3.1 *Company Specific Versus Industry TFP Targets*

1. Lister proposes the use of the company's historic TFP trend, arguing that it doesn't weaken performance incentives and best reflects the business conditions of Enbridge.

PEG Response

Please see our response to IGUA question 40 for a full discussion of this proposition.

2. Lister also claims that PEG has supported company-specific TFP in the past. For example, in paragraph 60 (p. 26) of his testimony, Mr. Lister says that "in a recent PEG presentation, titled Overview of AltReg, PEG clearly stated that reliance on company-specific information is viable in establishing a benchmark. PEG echoed this finding in a latter presentation, Range of AltReg Options as well."

PEG Response

These remarks were made by PEG partner Larry Kaufmann, who has had little involvement in this OEB project, and not by managing partner Mark Lowry, who is its principle investigator and witness in this proceeding. Because of the partnership structure of the PEG business, Dr. Kaufmann is not obliged to have positions that are consistent with those of Dr. Lowry. Please note, in any event, that it is clear from examining the entirety of Dr. Kaufmann's presentations at the Boston conference that these statements do **not** support the conclusion that it is generally desirable to set productivity targets using company specific information. A complete investigation of these presentations (which are attached) shows that PEG's support of the use company-specific information applied to benchmark-based plans only and not to indexing mechanisms.

For example, slide 13 in Dr. Kaufmann's Overeiw of AltReg (attached as IGUA 12 Overeiw of AltReg.ppt) presentation does say that benchmarks can be based on company-specific information, but the information presented in the Range of AltReg Options (attached as IGUA 12 Range of AltReg Options.ppt) presentation makes it very clear where PEG believes this is appropriate. Slide one of this latter presentation presents a "Taxonomy of Basic PBR Options" that clearly distinguishes between Index-Based Mechanisms (for prices or revenues) and Benchmark-Based Plans (including comprehensive plans and those that apply to service quality). Slide two in this presentation discusses rate indexing plans of the type that PEG has proposed for Ontario's gas distributors and says "in North America, X factors are usually based on *industry* productivity and input price trends" (emphasis added). Slide 16 mentions 'benchmark plans' and includes the first explicit mention of benchmarks, which are defined on this slide as "external standards of comparison for activity variables." Slide 18 of this presentation says that the most common approach for determining such benchmarks in benchmark plans is the company's own historical performance.

It is also abundantly clear from PEG's written work that we generally support the use of industry and not company-specific TFP trends to calibrate X factors. PEG personnel have testified dozens of times in support of industry TFP trends but have never supported the use of company specific TFP trends to set X factors in proposed PBR plans. Mr. Lister's conclusions are therefore based on a conflation of recommendations for different types of PBR plans and are not supported by either the presentations he cites or PEG's broader experience and work.

3.2 Definition of Industry and Selection of Peer Groups

1. PEG created TFP trend peer groups for Enbridge and Union to provide a point of comparison for the econometrically-based peer group targets. The average TFP growth rates of the peers were similar to those of the econometric targets, thereby substantiating the notion that Enbridge and Union should have targets well *above* US norms. Lister makes numerous criticisms of this approach and presents as an alternative a northeast US peer group that has average TFP growth well *below* the US norm.

PEG Response

Please see the response to IGUA Question 40 for a full discussion of this issue.

2. Lister notes that PEG has used Northeast peer groups in TFP testimony for Boston Gas, and in that work featured a northeast dummy variable in its econometric cost model.

PEG Response

The Massachusetts DTE made reference to an (irrelevant) northeast dummy variable in the econometric cost model of a *non-PEG* witness when it first approved a TFP target for Boston Gas based on a northeast peer group. PEG partner Larry Kaufmann has since included a northeast dummy variable in his econometric models filed in Massachusetts as a courtesy to the Board. Please also note that these models were used in the Massachusetts evidence to benchmark econometric cost *levels*. In such an application, a northeast dummy variable may be germane. In any event, the fact that a northeast peer group is relevant *for a Northeast utility* says nothing about its suitability for use in a very different business environment such as the rapidly growing economy of southern Ontario. All the Massachusetts gas utilities for which this peer group has been applied are, in fact, relatively slow growing and have some of the most cast iron and bare steel intensive systems in the country. These factors are not true for EGDI.

3.3 Instability of Results

Carpenter notes with concern the stability of the TFP results produced from essentially the same sample.

PEG Response

Please see our response to IGUA question 42 for a full explanation of these differences.

3.4 *Weather Normalization*

Lister questions on pp. 6-7 various aspects of the weather normalization method used by PEG. In particular, he cites

- Use of annual rather than monthly heating degree days
- Predictive power of the econometric model used in normalization
- No distinction between heating load and base load.

PEG Response

1. Enbridge has not demonstrated that monthly heating degree days or a distinction between base load and heating load really matters. This is just one of many examples where they mention an issue that *might* affect the value of X but do not demonstrate that it actually *does* and would materially *reduce* X.
2. PEG has more than 40 man years of experience in the field of statistical research. We believe that an R^2 of 45% is quite respectable in a model of this purpose.
3. The PEG method is similar to that used by Union and produces weather adjusted volume trends that are similar to Union's. However, it produces quite different results for Enbridge than the company's own method.
4. The Enbridge weather normalization method may be suitable for use in rate cases but is unsuitable for use in TFP trend research because its backward looking character makes it too sensitive to the particular pattern of past weather fluctuations.

In conclusion, the PEG approach to weather normalization is preferable to that of Enbridge for purposes of calculating the EGD long term TFP trend.

3.5 *Measure of Output Growth*

PEG employed an elasticity-weighted output index to set the X factor for the revenue cap index in its June report. Bernstein instead argues (p. 16-18) that the output index should be *revenue-weighted* even though the Company is proposing a revenue *per customer* index. He states at 16 that "Under PCR or RCR, industry TFP growth rates should capture the historic trend in the service usage for the gas utilities. This salient feature of productivity growth services to *guarantee* that the regulated firm under IR does not acquire excessive profit [italics added]". At p. 18 Bernstein states that "a cost elasticity share-weighted industry TFP growth rate differs from the revenue share-weighted industry TFP growth rate and the former rate generally provides *no guidance* as to the appropriate PD component, and resulting X factor under IR [italics added]."

PEG Response

PEG once again disagrees strongly with Dr. Bernstein. The mathematical reasoning that generally supports the index-based regulation suggests that a revenue-weighted output index is incompatible with a revenue per customer cap. The PEG research results can be readily adjusted to provide the appropriate X factor. Suppose that the trend in the revenue requirement equals the trend in cost, which is the sum of the trends in input price and productivity indexes:

trend Revenue = trend Cost = trend Input Prices + trend Inputs.

Now

trend Revenue =

trend Input Prices – (trend Customers - trend Inputs) + trend Customers

so that

trend Revenue – trend Customer

= trend (Revenue/Customer)

= trend Input Prices-(trend Customers - trend Inputs).

The relevant output index for a revenue/customer cap index is thus the *number of customers*, much as the relevant output index for a PCI is revenue-weighted.

PEG has consistently used the number of customers as the output index in productivity studies designed to support revenue per customer caps. Dr. Melvyn Fuss chose the number of customers as the output measure for his productivity index when he testified in support of the Enbridge O&M expense index in its TPBR plan and the Board agreed on its appropriateness. Enbridge and/or its consultants have employed the number of customers as an output measure in several of its own published productivity studies.

We can easily correct the revenue cap index that we propose in the June 20 report by adding a revenue per customer adjustment to the X factor. Results can be seen in the attached table IGUA 12 Revenue per Customer. PDF. The resultant cost growth is the same, as it should be. The resultant X factor is far higher than that which would result from the use of Bernstein's proposed revenue-weighted output index.

3.6 The Input Quantity Index

3.6.1 Irreversible Capital and Capital Adjustment Costs

Dr. Bernstein states on page 39 of his evidence that "PEG assumes capital to be variable and reversible. But econometric cost models demonstrated that these assumptions have been rejected. In fact recent estimates indicate that investment irreversibility leads to an overestimation of TFP growth in US telecommunications by 33% on an annual basis, and increases the hurdle rate of return characterizing profitable investment projects by as much as 35%."

PEG Response

However, the "recent econometric work" that Bernstein cites is in fact highly speculative, and capital irreversibility is not reflected in either mainstream TFP measurement or cost function estimation. The estimates in question were made in an unpublished NBER working paper[6]. This paper noted on page 12 that "For the *first time* this paper introduces estimates of the premium due to irreversible investment in the measurement of TFP growth" (emphasis added). No previous research on the link between irreversibility and TFP calculation has apparently ever been published in a scholarly journal.[7]

It is also worth noting that Dr. Bernstein has published other articles on productivity measurement for utility industries, and none of these papers includes an adjustment for capital irreversibility, even in his most recent paper on X factor calculation.[8] Dr. Bernstein has also written a paper with Dr. Sappington on the form of the X factor, and this paper discusses the theoretical potential to adjust the X factor for factors other than TFP and input price trends. This article does *not* discuss the potential

---

[6] Bernstein, Jeffrey; and Mamuneas, Theofanis P. (2007) "Irreversible Investment, Capital Costs and Productivity Growth: Implications for Telecommunications." May 2007 NBER Working Paper.
[7] The working paper is scheduled to be published in the *Review of Network Economics*, September 2007.
[8] Bernstein, Jeffrey (2006). "X-Factor updating and total factor productivity growth: the case of Peruvian telecommunications, 1996-2003." *Journal of Regulatory Economics*, 30:316-342.

or importance of adjusting X factor estimates to reflect capital irreversibility or capital adjustment costs.

In sum, PEG's treatment of capital costs has a firm foundation in economic science and published academic studies. Dr. Bernstein's recommendations on the importance of capital irreversibility and capital adjustment costs are not reflected in the mainstream academic literature.

It should also be noted that PEG developed the COS approach to capital costing partly out of a concern that Enbridge, with its rapid customer growth, might be experiencing unit cost escalation under COS that was not captured by GD capital costing.

3.7 *Adjusting the TFP Target for the US-Productivity Gap*

Lister contends (pp. 3-6) that a productivity target based on US operating data should be adjusted for an alleged gap between productivity between the US and Canadian gas distribution industries. He cites research by the Centre for the Study of Living Standards (CSLS) that found that the TFP trend of the Canadian gas distribution industry grew at a -1.2% average annual pace from 1988 to 2005 and a pace of -0.4% 2001-2005. He cites, additionally, a report by Rao, Tang and Wang of Industry Canada on a large (50%) gap in 2004 between the productivity levels of US and Canadian utility sectors. On this basis, Lister argues for a downward productivity gap adjustment to any TFP target based on US data.

PEG Response

1. The CSLS numbers on gas distribution TFP trends are calculated using an implicitly *revenue*-weighted output index. This will reduce the TFP trend of the industry considerably relative to the *elasticity*-weighted output quantity index that PEG uses. Using a *revenue*-weighted output index and its own methods PEG calculates, for instance, a -0.1% average annual trend in the TFP index for Enbridge 2000-2005 rather than the +0.71% average annual trend that we feature in our report. This reduction is effected through the average use adjustment.

2. Despite the heavy implicit weight placed on volume growth in the CSLS index the output index isn't weather-normalized as it should be if we seek to capture a long-term TFP trend using average annual growth rates from fixed sample periods.

3. TFP index numbers for Canadian distributors are sensitive to the slow productivity growth of Enbridge, since it accounts for a large share of Canada's gas distribution industry.

4. Lister neglects to report any of the *Statistics Canada* indexes of utility productivity that are available. The labeled "IGUA Q12 Canadian Productivity" juxtaposes the CSLS Canadian TFP indexes for gas utilities and all utilities with analogous indexes produced by Statistics Canada. The Table reveals marked differences in the Statistics Canada and CSLS results. For example, over the longest overlapping period for which data are available for both indexes (1994-2003), CSLS reported a -0.9% for all Canadian utilities whereas Statistics Canada reported a +1.8% trend for the same group! This finding is especially striking in view of the fact that, when discussing the relative merits of these MFP measures, CSLS itself recommends that their own statistics **not** be used, saying:

    > Statistics Canada recently released free estimates of productivity in Canada for the 1996-2005 period. The CSLS strongly recommends the use of official data over the CSLS database. However, the CSLS database can be useful for individuals who wish to study a longer period or those who need provincial data.[9]

5. One factor that might explain a productivity gap is material differences in the taxation rates of US and Canadian companies. PEG perused the literature in search for information on this issue. A 2005 commentary "The 2005 Tax Competitiveness Report: Unleashing the Canadian Tiger" by Mintz *et al* for the C.D. Howe Institute presents a table on "Marginal Effective Tax Rates on Capital for Large and Medium Sized Corporations 2005". This is attached as IGUA 12 Taxes. PDF. It can be seen that the effective tax rates in Canada, while high, are *quite similar to those in the US.*

[9] Capital, Labour, and Total Factor Productivity Tables by Province, 1987-2006, NAICS based. CSLS website. http://www.csls.ca/data

6. If a US-Canada productivity gap does exist, Enbridge draws the incorrect conclusion about the implications for the future TFP growth of an Ontario gas distributor operating under IR. Enbridge implies that an industry with a lower productivity *level* now should have lower TFP *growth* in the future. In fact, the opposite is more likely to be true. This concept is explained in the very Rao, Tang, and Wang (2004) document that Lister cites. The authors state that

> Future productivity growth prospects partly depend upon the current gap with the productivity leader, the United States. *The higher the level gap, the larger the scope for a faster productivity growth in Canada due to catch-up, and vice versa* [italics added].[10]

This conclusion is all the more noteworthy inasmuch as the gap in TFP levels that the authors report is especially large for the utilities industry.

It is also well established in the empirical literature that a "productivity gap" is expected to lead to *convergence* of productivity levels among countries (or industries in different countries) over time due to spillovers in technology and foreign investment. Convergence can only occur if TFP growth for the less productive industry grows more rapidly than TFP growth for the leading international industry. In the US-Canadian context, this would imply that the TFP of Canadian gas distributors must grow more rapidly than their US counterparts for there to be productivity "catch up." Moreover, the rate of convergence is directly proportional to the size of the gap, and some research shows that productivity catch up is especially strong for the utility and services sectors[11].

All these factors imply that Canadian utilities may expect *higher* TFP growth than comparable US utilities when operating under IR. This potential for greater TFP growth could reasonably be reflected in a higher consumer dividend than the 0.5% that is

---

[10] Rao, Someshwar; Tang, Jianmin; and Wang, Weimin. (2004) "Measuring the Canada-U.S. Productivity Gap: Industry Dimensions." *International Productivity Monitor*, Fall 2004, page 4.

[11] The "utility" sector is the most specific industry category available in this literature. See the following references: Bernard, Andrew B. and Jones, Charles I. (1996), "Comparing Apples to Oranges: Productivity Convergence and Measurement Across Industries and Countries", *The American Economic Review*, 1216-1238. Baily, Martin Neil and Solow, Robert M. (2001), "International Productivity Comparisons Built from the Firm Level", *The Journal of Economic Perspectives*, 151-172. Conway, Paul; Rosa, Donato de; Nicoletti, Giuseppe; and Steiner, Faye (2006), "Regulation, Competition and Productivity Convergence, Economics Department Working Papers No. 509", OECD, 1-52.

common for US utilities and which PEG has recommended for Ontario's gas distributors. If any adjustment in X factors is warranted for the US-Canada productivity gap, it is therefore the opposite of the reduction in X which Mr. Lister apparently advocates. Enbridge seems, amazingly, asking for an unusually *low* X factor because of poor operating performance even though it has bragged about its good operating performance on many past occasions, including two econometric benchmarking studies commissioned by PEG!

3.8 Service Specific X Factors

Bernstein says that service specific X factors involve an arbitrary reallocation of the AU factor and inappropriately estimates TFP for specific service groups.

PEG Response

Please see our response to IGUA 11.

4. Econometric Research

4.1 Inadequacies of the PEG Econometric Work

PEG makes a number of uses of estimates of cost elasticities which it obtains from econometric cost research. Enbridge has numerous criticisms of the econometric research that produces the estimates, thereby calling into question the propriety of PEG's X factor calculations.

1. Lister comments (p. 12) on the "instability" of the results, including estimates of trend variables that range from -0.8% to -1.2%. He comments also on the different samples used in model estimation.

PEG Response

PEG believes that the results are *quite stable* considering the material changes in the models that were undertaken to make results more relevant to Ontario. These changes include…

- A decomposition of the delivery volume so as to separately measure the cost impacts of changes in residential and commercial volumes --- important to the cost of both Enbridge and Union --- and the other business volumes that are important only to the cost of Union. The sample size in later models was reduced because some companies didn't report this decomposition.
- The use of a COS rather than a GD approach to capital costing so as to facilitate the calculation of IPDs and make sure that the rapid growth challenges of Enbridge are recognized.
- Some models have trend-input price interaction terms while others do not.

2. Bernstein criticizes PEG's econometric work on the grounds that the model was restricted in ways that could influence results. One concern is the lack of interaction terms for the output variables.

PEG Response

PEG generally employs flexible functional forms in its econometric research. The only noteworthy restriction on flexibility in this model is the elimination of interaction terms between the output variables. This was done for only one reason: to obtain reasonable estimates of the company specific cost elasticities. The inclusion of these interaction terms resulted in negative output elasticities for up to half the sampled firms, a result contradictory to cost theory. Unreasonable elasticity estimates proved problematic in the calculation of the ADJ factor.

In general, there is always a tradeoff between econometric specifications and available data; sometimes it makes sense to employ different, even "restricted" specifications, to obtain results that are more theoretically plausible, especially if data are relatively limited.

3. Dr. Bernstein states (p. 6) that "PEG's model contains severe restrictions prohibiting parameters to differ among firms, not just for a single year, but for all years in the sample." He continues on page 31 of his evidence by asserting that "PEG did not allow for firm or time differences…this means that all firms are assumed to have the same cost function, and the same input demand functions, not just for a single year but for all years in the sample."

PEG Response

Econometric cost models that, like the PEG model, are estimated using panel data sets do sometimes allow some model parameters to vary by company. However, this flexibility is almost always confined to the constant term, which is *not used in the calculation of the TFP target.*

Allowance for a time-varying constant term could have some effect on the estimates of parameters that are used. However, PEG, with its unrivalled experience in utility statistical cost research, has found that the use of this approach does *not* produce superior estimates. We instead account for some firm-specific conditions by including variables for exogenous business conditions, which vary across firms. If firm-specific effects have already been accounted for by the inclusion of these variables, the use of what are known as "fixed-effect" estimators would lead to a significant loss in model efficiency and therefore the ability to determine cost efficiency. A model using our approach was recently published in a respected peer reviewed journal.[12] Moreover, the same general approach was twice used in econometric benchmarking studies for Enbridge without any complaint from the client.

As for variances across time which are not captured by a trend variable, it's worth noting that in Dr. Bernstein's comparable telecom papers[13], he imposes the constraint of his parameter estimates remaining constant across the entire survey period of 1953-1979. No evidence is provided in these papers that he checked for structural change in his cost function parameters.[14]

4. Carpenter (p.5 and p. 14) criticizes the PEG model for its lack of a customer density (*e.g.* customers per line mile) variable.

PEG Response

PEG considered the introduction of a line miles variable into the econometric model and did find it to be statistically significant. We excluded this variable from the

---

[12] Lowry, Mark Newton, Getachew, Lullit and Hovde, David (2005), "Econometric Benchmarking of Cost Performance: The Case of US Power Distributors", *The Energy Journal*, 75-92.
[13] See Bernstein (1988a), Bernstein (1988b), Bernstein (1989).
[14] The manufacturing-sector cost function of Bernstein (1991) does make an adjustment for a structural shift.

final model used to set the TFP target only because its inclusion made it impossible to split out residential and commercial deliveries from other deliveries. We tried to add some consideration of density to our model with the urban core dummy. *We acknowledge that a model with a line miles variable and a simpler volumetric specification is a valid alternative.* The implications of this alternative specification for the TFP target are unknown.

5. Enbridge witnesses dispute and contradict PEG's econometric evidence that the rapid output growth of Enbridge permits it to earn sizable incremental economies of scale that can materially accelerate the pace of its TFP growth. Lister, for instance, states (p. 10) that

> The Company has experienced some of the highest customer growth rates across Canada, which results in high upfront costs to support a long payback period which would put *downward* pressure on the Company's measured TFP relative to other distributors. That is, high customer growth in the short term, all else equal, will lower the measured TFP since, by definition, inputs are growing faster than the revenue-weighted TFP growth.

<u>PEG Response</u>

Evidence from various sources supports the existence of incremental economies of scale from output growth over a wide range of operating scales. That means that the rapid customer growth of Enbridge actually accelerates its TFP growth rather than slowing it as Lister suggests. The chief source of these economies is the special economies in the delivery of volumes in piping systems.

"Special economies in the delivery of volumes" refer to the fact that the unit cost of gas deliveries is negatively related to the volume of gas deliveries. In other words, the unit cost of delivering natural gas declines as the volume of delivered gas increases. There is extensive support in the economic literature that these economies are inherent in the technology of gas delivery. Below are two quotes from published studies that support the existence, and describe the sources, of scale economies in the delivery of natural gas.

- "Gas pipelines exhibit significant economies of scale in both construction and operation. Up to a very large capacity, the per-mile cost of construction varies with the radius of a pipeline but the capacity varies with the square of the radius. Per-unit operating costs also decline with increased volumes. Therefore, the construction and operating costs of one pipeline are usually lower than the costs of two parallel pipelines each transporting half as much gas." (Bernhardt, J. (Feb. 1998), "Is Natural Gas Pipeline Regulation Worth the Fuss?," *Stanford Law Review 40*(3), pp. 757-758)

- "(One of the) basic facts of nature (are the)…powerful economies of scale in pipeline transmission…pipelining is a classic example of scale economies and local 'natural monopoly.' The capital costs of a line, given the terrain, are less than directly proportional to the amount of steel needed, since right of way and installation costs vary little with line diameters. Steel requirements are proportional to nearly the square of the diameter (therefore ***of*** the radius) of the line. Operating cost is a matter of overcoming the friction of the fluid against the inside of the pipe; the friction is directly proportional to radius. But the output of the line, i.e. the amount of oil or gas which can be carried in a given period, is ***more** than* proportional to the cross section area, i.e. to more than the square of the radius. Hence a 36-inch pipeline may be expected to cost rather ***more** than* twice as much as an 18-inch line, but to carry substantially more than four times as much, so that the unit cost is about half (see below, Table 111, p. 49). Even if the amount of available gas is greater than can be carried most economically in the 36-inch line, it is usually cheaper to increase pressure and pay to overcome the additional friction with additional compressor stations than to build, say, two 24-inch lines." (Adelman, M.A. (1962), "The Price of Natural Gas Reserves. *The Journal of Industrial Economics, Vol. 10 Supplement: The Supply and Price of Natural Gas*, pp. 44-45)

PEG's econometric research on the drivers of gas utility cost supports the notion that extensive incremental scale economies are available even for large companies like Enbridge. In our econometric cost model for the OEB we find that the parameter for the quadratic term for residential and commercial deliveries is negative and statistically significant. This conclusion is further supported by PEG's analyses of gas distribution costs over the last decade, which almost invariably finds that the coefficient on the quadratic term for gas deliveries is negative (although it is not always statistically significant). Even in those cases where the coefficient on the quadratic term for deliveries is not statistically significant, PEG has always found that economies of scale exist at the sample mean for gas distributors.

Below we produce the key results for all eleven gas distribution econometric cost studies that PEG has published in the last decade that we still have suitable records of. For each study we list:

- The name of the client (SDG&E is San Diego Gas and Electric, SoCalGas is Southern California Gas, Multinet is a gas distributor in Victoria, Australia, and 'New Zealand' applies to two NZ gas distributors: Vector and NGC)
- The date of the study
- Whether the study benchmarked or analyzed total gas distribution cost (TC) or operating and maintenance costs (O&M)
- The coefficient on the quadratic term for gas deliveries (VV)
- The t-statistic associated with the coefficient on the quadratic term for gas deliveries
- The sum of the estimated output elasticities at the sample mean level of output

Client	Date	Costs	VV Coefficient	VV T Stat	Sum Output Elasticity
SDG&E	1/98	TC	.010	0.13	.755
Multinet	9/01	O&M	-.125	-0.52	.843
SoCalGas	12/02	TC	-.487	-4.17	.855
Enbridge	1/03	O&M	-.395	-3.50	.875
Boston Gas	4/03	TC	-.512	-6.83	.868
SDG&E	2/04	TC	-.365	-2.62	.928
Enbridge	2/04	O&M	-.440	-2.72	.944
New Zealand	6/04	TC	-.085	-1.17	.688
Bay State	4/05	O&M	-.054	-0.36	.612
SDG&E	8/06	TC	-.041	-0.05	.867
ESC (Aus.)	6/07	O&M	0.17	0.14	.767

It can be seen that the coefficient on the quadratic term for deliveries was negative in nine of the 11 applications and this coefficient was statistically significant in five of those nine studies. The estimate was not found to be *positive* and statistically significant in any study. Please note that all of these studies involved fully translogged output specifications. We also find that incremental scale economies exist at the sample mean in each of the studies, with an average for the sum of the output elasticities equal to .818. This means that 1% growth in all output variables raises cost by only 0.818% for a firm of sample mean size.

Please note, additionally, that we emphasize the negative quadratic term for the volume variable because it is apparently the special reason for unusual scale economies. We acknowledge that the *quadratic term on the number of customers* has a positive sign. However, this is *insufficiently large to lead to an exhaustion of scale economies at large levels of output.*

PEG agrees in principle that at some point scale economies will plateau and be exhausted, but the point at which this occurs is not a *theoretical* issue but an *empirical* one and can vary substantially across industries. Dr. Carpenter presents *no* empirical evidence to support his claim that scale economies have in fact been exhausted for Enbridge but simply says this will occur "at some point" (p. 18). In gas distribution, the empirical evidence suggest that sizable scale economies are available even for the largest firms in the industry. The TFP trends that we report for individual US utilities in Tables 8a, 8b, 9a, and 9b are consistent with this finding. It can be seen that a number of large utilities experienced rapid TFP growth during the sample period.

PEG also believes that its finding that scale economies exist at the mean of our US gas distribution sample is reasonable and consistent with most of the literature on this issue. For example, Fabbri, Fraquelli and Giadrone present a survey of empirical literature on estimated scale economies in gas distribution industries.[15] Their survey shows that every econometric study that has used flexible form cost models like the translog has found evidence of scale economies. It is well-known that the translog cost function allows scale economies to be estimated more precisely than alternate specifications like the Cobb-Douglas. The one (partial) exception to this finding is by Kim and Lee (1996) for the Korean gas distribution industry, but this was a study that was done for the first five years of the industry's existence (1987-1992). Such a "start up" industry may be characterized by significant amounts of initial investment and

[15] Fabbri, P., G. Fraquelli and R. Giandrone (2000), "Costs, Technology and Ownership of Gas Distribution in Italy," *Managerial And Decision Economics*, 71-81.

relatively few initial customers, which can distort the long-run relationships between costs and output that may be expected in more mature gas distribution industries.

Please note, finally, that Carpenter provides no substantiation for his assertion on p. 14 that companies with increasing line miles per customer are especially likely to exhaust incremental scale economies. This is an empirical issue and can be proven only with empirical evidence.

Overall, our research supports the conclusion that growth in gas distribution output (particularly growth in gas deliveries) can produce scale economies even for large companies like EGDI. Since, additionally, incremental scale economies can be an important source of TFP growth, our research also shows that the growth in gas distribution output is an important criterion for selecting an appropriate TFP growth peer group for EGDI. These findings argue against the use of a northeast peer group for Enbridge since output growth is much slower in the northeast than in metropolitan Ottawa and Toronto.

4.2 Use of Econometrics to Set the TFP Target

PEG recommends the use of TFP targets that are based on mathematical theory regarding the drivers of TFP growth and on econometric estimates of cost elasticities. This research is subject to numerous criticisms by Enbridge witnesses.

1. Lister queries why three other business conditions in the PEG model are not used to calculate the TFP targets.

PEG Response:

One of these variables (the number of electric customers) is inapplicable because neither Enbridge nor Union serves electric customers. The second (urban core dummy) is inapplicable because its value doesn't change over time. The third (% of miles cast iron) would *raise* the X factor, which probably doesn't make sense in the short run.

2. Lister states (p. 14) that "other utilities have moved away from econometric modeling." He cites PG&E and Southern California Edison as examples of this trend, quoting the latter's most recent GRC which argued that "Our previous experience with productivity models is that they generally produce imprecise estimates of productivity growth."

PEG's Response:

PG&E and SCE moved away from econometric modeling of TFP trends because they were estimating the cost models using only *company specific* (*i.e.* their company's own) *data*. Estimates of underlying parameters were therefore negatively impacted by low degrees of freedom and from the lack of variability in sample data which, as PEG has noted, tends to improve the reliability of statistical estimates. PEG has used a nationwide sample of data to eliminate the problem that PG&E and SCE faced. The real importance of the PG&E and SCE precedents is that the California PUC, with a staff that includes several PhD economists, sanctioned the use of econometrically based TFP targets on several occasions. Moreover, the formulas employed were similar to those used by PEG.

It is also worth noting that econometrics is currently being used in another gas distribution proceeding. The Essential Services Commission in Melbourne, Australia has issued a Draft Determination for allowed gas distribution charges over the term of an upcoming PBR plan. Allowed opex under this plan is determined using an indexing mechanism, and one of the elements of the opex indexing formula is the trend in the partial factor productivity (PFP) of opex. The opex PFP trend was estimated using econometric methods (applied to both US and Australian-New Zealand datasets) similar to those used to set the TFP target for EGDI in this proceeding.

In summary then, there is substantial precedent for the use of TFP targets based on econometric research and no tendency for regulators to move away from this approach based on its lack of merit.

4.3 *Cast Iron Replacement Expenditures*

PEG performed auxiliary regressions of the growth in TFP on the growth in the number of customers and the change in the percentage of mains that are not cast iron. This was part of an attempt to give Enbridge the benefit of the doubt concerning the impact of cast iron replacement on its unit cost. The inclusion of customer number changes in this latest work makes our conclusions about the effect of cast iron changes on TFP even stronger. This is because utilities with a high percentage of cast iron on their systems are located disproportionately in the northeastern states, where slow customer growth limits opportunities for scale economies. Econometric analysis permits us to assess the impact of both conditions simultaneously. We could not reject the hypothesis that a change in cast iron reliance has no effect on TFP growth.

1. Bernstein objects to the implications of our coefficient on percent of cast iron on TFP growth, which implies that reducing the percent of cast iron main reduces cost and hence increases TFP growth. He says this conflicts with the fact that replacing cast iron pipe requires new investment, which tends to depress TFP growth. This is not a contradiction in principle but merely a reflection of the difference that capital investment decisions can have on long run and short run TFP growth. Bernstein himself has discussed this in his Fall 2000 article "Price Cap Regulation and Productivity Growth", where he says

> Large capital projects, embodying technological advances, may be required over some time period, followed by a period of relatively low investment. These lumpy and discrete capital additions initially lead to higher costs and thereby lower productivity growth. However, once the new capital is deployed, productivity growth increases. Short-term productivity fluctuations are exacerbated in capital-intensive industries, such as telecommunications, resulting from timing mismatches of costs and revenues. (Page 26)

Bernstein's testimony emphasizes only the first two sentences from the quote above, about the short-term impact of capital spending on TFP growth. He omits the following sentence, which is that new capital raises TFP in the future. This sentence would definitely be relevant when discussing the replacement of old cast iron pipes with newer, plastic pipes, which are much less prone to leaks and otherwise have lower maintenance costs and, hence, contribute to greater TFP growth. A long-run TFP growth trend estimate would have to pick up both the short-term negative effect that results while capital is being invested and the longer-term positive effect from using improved capital; Bernstein's testimony recommends adjustments of the TFP trend only for the former effect.

2. Carpenter states that our auxiliary regression results do not shed light on the TFP impact of a cast iron *replacement* program.

PEG Response

PEG has revisited this issue since filing the June 20 report by regressing TFP growth on customer growth and a variable that represents the magnitude of reductions in cast iron main. Results of 2 representative runs can be found in the labeled "IGUA 12 Cast Iron.xls". The estimate of the parameter of the new cast iron variable was statistically *insignificant* using *both* one and two-tailed tests. Our failure to find statistical significance for cast iron variables suggests to us that the O&M productivity savings that result from cast iron replacement substantially offset the short term growth in capital cost. The slow productivity growth of utilities in the northeast that have extensive cast iron is due, instead, to slow customer growth that limits their opportunities to realize scale economies. Please note also that, according to the table prepared by Lister, Enbridge in fact has *very little* cast iron compared to the typical northeastern US utility.

Comparison of Utility Sector Productivity Trends from Centre for the Study of Living Standards (CSLS) and Statistics Canada, 1994-2005

	Utilities					
	Stats Canada MFP - gross output[1]		Stats Canada MFP - Value Added[1]		CSLS TFP - Value-Added[2]	
	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1994	79.7	4.8%	94.9	3.3%	96.0	2.9%
1995	84.3	5.6%	100.0	5.2%	99.7	3.8%
1996	87.6	3.8%	98.8	-1.2%	100.7	1.0%
1997	89.4	2.0%	89.4	-10.0%	100.0	-0.7%
1998	87.7	-1.9%	87.7	-1.9%	96.5	-3.6%
1999	90.4	3.0%	90.4	3.0%	96.8	0.3%
2000	91.8	1.5%	91.8	1.5%	94.6	-2.4%
2001	94.9	3.3%	94.9	3.3%	86.9	-8.4%
2002	100	5.2%	100.0	5.2%	89.6	3.1%
2003	98.8	-1.2%	98.8	-1.2%	88.9	-0.8%
2004					87.4	-1.7%
2005					89.0	1.8%
Average Annual Growth Rates						
1994-2003		2.4%		0.4%		-0.9%
2001-2005						0.6%

1 Table 383-0022, Statistics Canada CANSIM series.
2 Centre for the Study of Living Standards, Income and Productivity Data. Labour, Capital and Total Factor Productivity by Industry for Canada and the 10 Provinces - based on NAICS. (Updated July 26, 2007)
Table 7: Total Factor Productivity by Industry using Employment as the Labour Input, 1987-2006.

Both series current as of August 2007.

IGUA 12 Revenue/Customer

Revenue Per Customer Cap Indexes: Results Using PEG Calculations

	Enbridge	Union
Productivity Differential [A]	0.89	0.52
Revenue Per Customer Adjustment [B=B1-B2]	0.44	0.19
Customer Growth [B1]	*3.27*	*2.11*
Output Growth [B2]	*2.83*	*1.92*
Input Price Differential [C]	0.27	0.22
Stretch Factor [D]	0.50	0.50
X Factor^{RCI} [E=A+B+C+D]	2.10	1.43
Customer Growth [F]	3.27	2.11
GDPIPI [G]	1.86	1.86
Indicated RCI Growth [G-E+F]	3.03	2.54

Overview of Alternative Regulation (AltReg)

Larry Kaufmann, *Partner*
Pacific Economics Group, LLC

Alternative Regulation for Electric and Gas Utilities

Boston, MA
June 25, 2007

Pacific Economics Group, LLC
Economic and Litigation Consulting

Introduction

Alternative approaches to energy utility regulation have become common in recent years

- Many alternative regulation plans have now been approved
- Experience under performance-based regulation (PBR) is accumulating
- Varied approaches and many options to choose from

This presentation is designed to provide an overview on PBR basics

Rationale for PBR

Cost of Service Regulation

Cost of service regulation ("COSR") is still the primary form of energy utility regulation in North America

- Paradigm: Rates recover the prudently incurred cost of service
- Periodic rate cases examine costs and their prudence

Rationale for PBR (con't)

Cost of Service Regulation

COSR has made utility services available to all at affordable rates

Despite success, dissatisfaction with COSR has encouraged experimentation with other arrangements

- Competition
- Alternative Regulation

What's the problem?

Rationale for PBR (con't)

Some Criticisms of COSR

- Adversarial process
- High regulatory costs
- Lack of incentive for cost control
- Disincentives for innovation
- Risk averse management
- Micromanagement by regulators
- Inflexible and less than efficient pricing

Rationale for PBR (con't)

COSR especially unsuited to volatile conditions and/or persistent upward cost pressures

- Slow, cumbersome process
- Limited operating flexibility
- Can invite opportunistic prudence reviews

Current environment characterized by

- Volatile fuel prices
- Required capacity additions
- Declining natural gas usage per customer

>>upward cost pressures

Rationale for PBR (con't)

Fundamental COSR Critique

Economists' critique:

Fundamentally a problem of <u>information</u>

Costly for regulators to make informed appraisals of utility operations

e.g. Rate cases are expensive & time consuming

Many traditional "short cuts" taken to contain regulatory cost are problematic

Rationale for PBR (con't)

Traditional Short Cuts

Limit scope of prudence reviews

Focus on practices with conspicuously poor outcomes

No rewards for superior performance

>>> Rates reflect company's own cost and output

Discourage practices that complicate regulation

Reduce rate case frequency

Pacific Economics Group, LLC
Economic and Litigation Consulting

Rationale for PBR (con’t)

Consequences

Linking rates to company’s own cost & output *weakens incentives*

Competitive Industries:	Cost down >>> Profits up Cost up >>> Profits down
COSR:	Cost down >>> Rates down Cost up >>> Rates up

Incentives especially weak for projects with long (*e.g.* 4-6 year) payback periods

Practices complicating regulation can improve performance

e. g. Market-responsive rates and services

Pacific Economics Group, LLC
Economic and Litigation Consulting

Rationale for PBR (con't)

Consequences (cont'd)

Regulatory lag *strengthens* performance incentives

Problems:

- Utilities need rate relief in longer run

  >>> Practical limits on regulatory lag

- Risk
- Delays in customer benefits

Rationale for PBR (con't)

COSR Conclusions

COSR is regulatory "technology" that may not achieve the best "bang" for the regulatory "buck"

Despite flaws, COSR can provide real performance incentives due to

- Prudence reviews
- 2-3 year regulatory lag

Alternatives to COSR can produce greater benefits

Pacific Economics Group, LLC
Economic and Litigation Consulting

Alternative Regulation

What is Alternative or Performance-Based Regulation?

Limits of COSR have stimulated search for alternative forms of regulation

Goes by many names

- Alternative regulation (AltReg)
- Incentive Regulation
- Performance-Based Regulation (PBR)
- Formula Rate Plans (FRPs)

Alternative Regulation (con’t)

Active Ingredients

PBR is a “rule-based” regulatory approach

>> rules that create

- Inherent incentives for utilities to achieve regulatory objectives
- Reasonable risk-return balance

Alternative Regulation (con't)

PBR rules include

<u>Reliance on *external* information</u>

e.g. Past company performance

External benchmarks (*e.g.* prices of other utilities)

Input price trends

<u>Automatic rate adjustment mechanisms</u>

e.g. Earnings sharing mechanisms

<u>Economic reason & empirical research</u>

Alternative Regulation (con't)

Potential Advantages

Lower regulatory cost

- Longer regulatory lag
- Lower administrative costs

Stronger performance incentives

- Cost control
- Pricing/marketing
- Innovative practices

>>> Larger expected benefits from regulation

Alternative Regulation (con't)

Potential Advantages (cont'd)

Plan parameters can be calibrated to share benefits between utility and its customers

>>> ”Win-Win situation”

- Bigger pie
- Bigger slices for everyone

Alternative Regulation (con’t)

PBR/Altreg Tools

PBR plans constructed from set of basic tools

- Rate Case Moratoria
- Plan Updates
- External Rate Adjustments
- Benefit Sharing
- Marketing Flexibility
- Service Quality

Important Design Objectives for PBR/AltReg

- Promoting efficient behavior
- Sharing benefits with customers
- Creating balanced incentives (*e.g.* cost and quality)

Comparing AltReg Options

Lawrence Kaufmann, *Partner*
Pacific Economics Group

Alternative Regulation for Electric and Gas Utilities

Boston, MA
June 25, 2006

Pacific Economics Group
Economic and Litigation Consulting

Introduction

Effective utility regulation should create

- Strong performance incentives for companies
- Benefits (e.g. lower prices) for customers

Strong performance incentives » lower unit costs
Lower unit costs » ultimate source of customer benefits

Introduction (cont..)

BUT there is usually a trade off between

- *Creating* incentives to perform efficiently
- *Transferring* efficiency gains to customers as lower prices

>> companies pursue efficiency to profit, transferring efficiency gains to customers reduces incentives to undertake actions that improve efficiency

Introduction (cont..)

Policymakers try to balance goals of incentives and customer benefit

Can be done many different ways

- Change term of incentive regulation (e.g. CPI-X) plan
- Add earnings sharing mechanism (ESM) to plan
- Transfer *all* efficiency gains customers end of plan
- Transfer *some* efficiency gains customers end of plan

Introduction (cont..)

These options involve many implementation decisions

- How long a plan term?
- What fraction of "over earnings" should companies keep during plan?
- Should the ESM have different sharing fractions for different levels of company earnings?
- Should the ESM have "deadbands"?
- What fraction of efficiency gains should be transferred to customer at end of plan?

All these options should consider the impact of these decisions on company incentives since that is the ultimate source of efficiency gains and *potential* customer benefits

Pacific Economics Group
Economic and Litigation Consulting

Introduction (cont..)

Evaluating these regulatory options very complex

Would be good if there was a tool that:

- *Quantified* incentive – benefit tradeoffs under different regulatory options
- Evaluated *long-term* impact or customers and companies of different regulatory regimes

Pacific Economics Group (PEG) has developed an "incentive power" model for these purposes

Plan of Presentation

I. Introduction
II. Incentive power idea
III. Current uses Incentive Power Models in utility regulation
IV. PEG's Incentive Power Model
  A. Basics
  B. Evaluation different regulatory regimes
  C. Implications
V. Conclusions

II. Incentive Power Idea

Known that different regulatory options have different implications for incentives

Can consider two polar cases:

- "pure" cost of service regulation

>> prices tied to company's own costs <u>each year</u>

- "pure" benchmark regulation

>> prices de-linked from company's cost <u>each year</u>

"Incentive Power"

- Summarizes strength of incentives in regulatory regime
- Generally increases as less weight placed on cost of service regulation

Pacific Economics Group
Economic and Litigation Consulting

II. Incentive Power Idea (cont..)

Early, simple incentive power model

$P = (1-b)\ c + b\ B$

P = utility price charged

C = utility's own cost

b = weight placed on external benchmark

>> b also is the "power" of the regulatory regime

II. Incentive Power Idea (cont..)

Actual regulation more complex

- Few if any cases of “pure” cost of service regulation (COSR) or benchmark regulation
- Most regulatory regimes somewhere between extremes
- Many different ways to design COSR and incentive regulation
- Practical incentive power model would take account of practical realities of regulation while still providing summary measure of “power” of regulatory regime between the polar extremes

III. Current Uses Incentive Power Model in Regulation

Incentive power work done for the regulator Ofgem by Frontier Economics

- Developing Network Price Controls: Workstream B
  Balancing Incentive
  March 2003
  A final report prepared for Ofgem
- Developing Network Price Controls: Initial Conclusions
  June 2003
  Ofgem

Documents can be downloaded/printed from www.ofgem.gov.uk under Distribution Price Controls work area

Pacific Economics Group
Economic and Litigation Consulting

III. Current Uses Incentive Power Model in Regulation (cont…)

Frontier: "We define the power of the incentive regime as the proportion of the present value of cost savings retained by the firm"

Intuitive, but not complete

- Does not explain how "the present value of cost savings" is generated
- Critical point because the analysis should focus on how regulatory regime *impacts* firm behavior
- Can lead to misleading inferences on what regulatory regimes create greatest long-run benefits

III. Current Uses Incentive Power Model in Regulation (cont…)

Example: Two regulatory regimes A & B

A: Generates $3m NPV cost savings
1/3 share goes to company, 2/3 share to customers

B: Generates $2m NPV cost savings
40% share goes to company, 60% share customers

	Total Company Benefits (NPV profit)	Total Customer Benefits (NPV price reductions)	Frontier Economics Incentive Power Measure
A	$1M	$2M	1/3
B	$0.8M	$1.2M	0.4

>> Frontier's measure identifies B as being more "powerful" seen though both customers and companies are worse off relative to A

Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model

PEG developing incentive power model around same time as Frontier

PEG's model focuses directly on:

- Impact of regulatory regimes on firm *behavior*
- Total NPV benefits generated for customers and companies
- Incentive power defined in terms of fraction of NPV cost savings generated relative to maximum amount NPV cost savings (in fully external, benchmark regulation)

PEG model presented in work for Essential Services Commission (ESC) in Victoria, Australia

IV. PEG's Incentive Power Model (cont…)

A. Basic PEG Model

Firm maximizes lifetime net present value (NPV) of profits subject to

- Regulatory constraints
- "technological" constraints

Regulatory constraints

- Initial price given
- Plan has a known term before prices are reviewed
- Benefit sharing *during* term of plan
- Benefit sharing when plan is *updated*

IV. PEG's Incentive Power Model (cont…)

A. Basic PEG Model (cont…)

Technical constraints:

- Firm has an array of projects available it can pursue that will reduce costs
- Projects differ in terms of:
  - One-time vs. permanent impact on costs
  - Whether projects reduce operating expenditures (opex) or capital expenditures (capex)
  - Up-front costs incurred to implement
  - "Payback periods" or how long it takes projects to pay for themselves given upfront costs

Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

A. Basic PEG Model (cont…)

Assumed eight available projects:

1. One-time reduction opex, no upfront costs
2. Permanent reduction opex, 1 year payback
3. Permanent reduction opex, 3 year payback
4. Permanent reduction opex, 5 year payback
5. One-time reduction capex, no upfront costs
6. Permanent reduction capex, 1 year payback
7. Permanent reduction capex, 3 year payback
8. Permanent reduction capex, 5 year payback

IV. PEG's Incentive Power Model (cont…)

A. Basic PEG Model (cont…)

Regulatory Scenarios:

– Specification COSR and degree of "externalization"
  - 2 year term, no externalization
  - 3 year term, no externalization
  - 2 year term, 5% externalization
  - 3 year term, 5% externalization

– Full externalization/benchmark regulations

>> Two polar cases

Incentive power measured relative to NPV cost

Savings under full externalization

Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

A. Basic PEG Model (cont…)
Other Regulatory Scenarios:

- Term
  - 3 year
  - 5 year
  - 10 year
- Earnings sharing
  - Company share = 75%
  - Company share = 50%
  - Company share = 25%
- Plan Updates
  - Full COSR "true-up"
  - 90% COSR true-up
  - 75% COSR true-up
  - 50% COSR true-up

Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

A. Basic PEG Model (cont…)
Firm solves profit maximization problem by choosing a path of cost reduction activities knowing technological and regulatory constraints (particular regulatory scenario)

>> which of eight potential cost reduction initiatives will prove profitable and will be pursued depends on regulatory regime

After model solves for firm's actions, cost reduction actions are inserted back into model to generate paths for

- Costs
- Profits
- Prices

Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

A. Basic PEG Model (cont…)

Pros:

- Very rigorous approach
- Realistic approach to company cost reduction strategies
- Extremely flexible, can consider thousands regulatory and cost reduction scenarios

Cons:

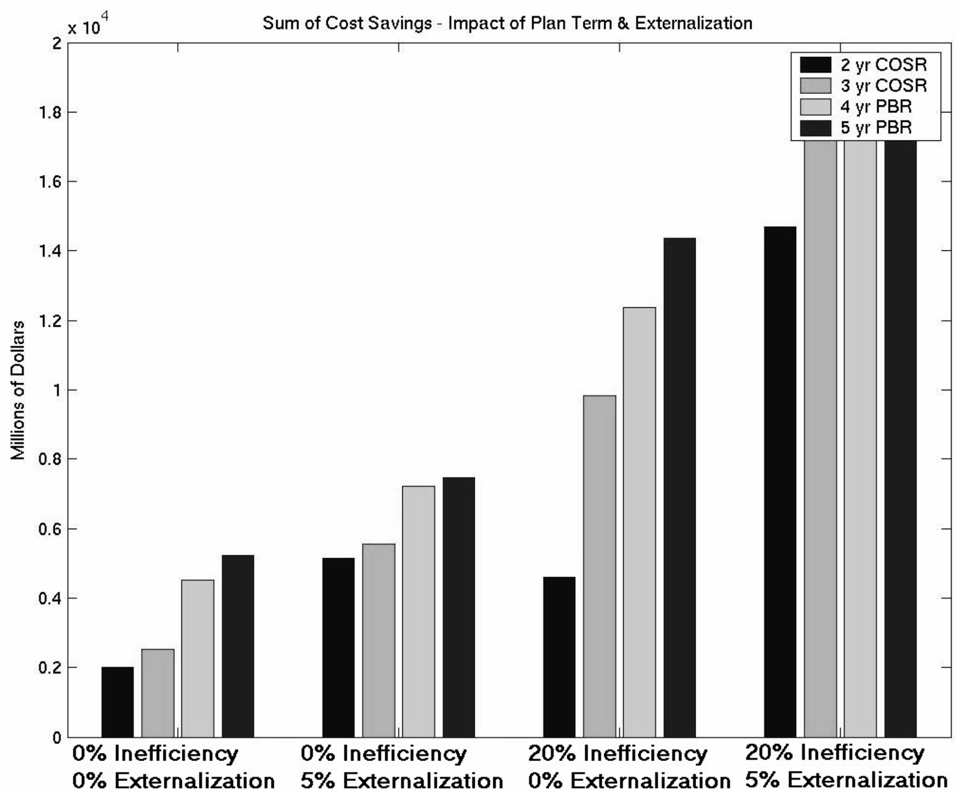
- Very complex

  >> no analytical solution

  solved with numeric optimization techniques

IV. PEG's Incentive Power Model (cont…)

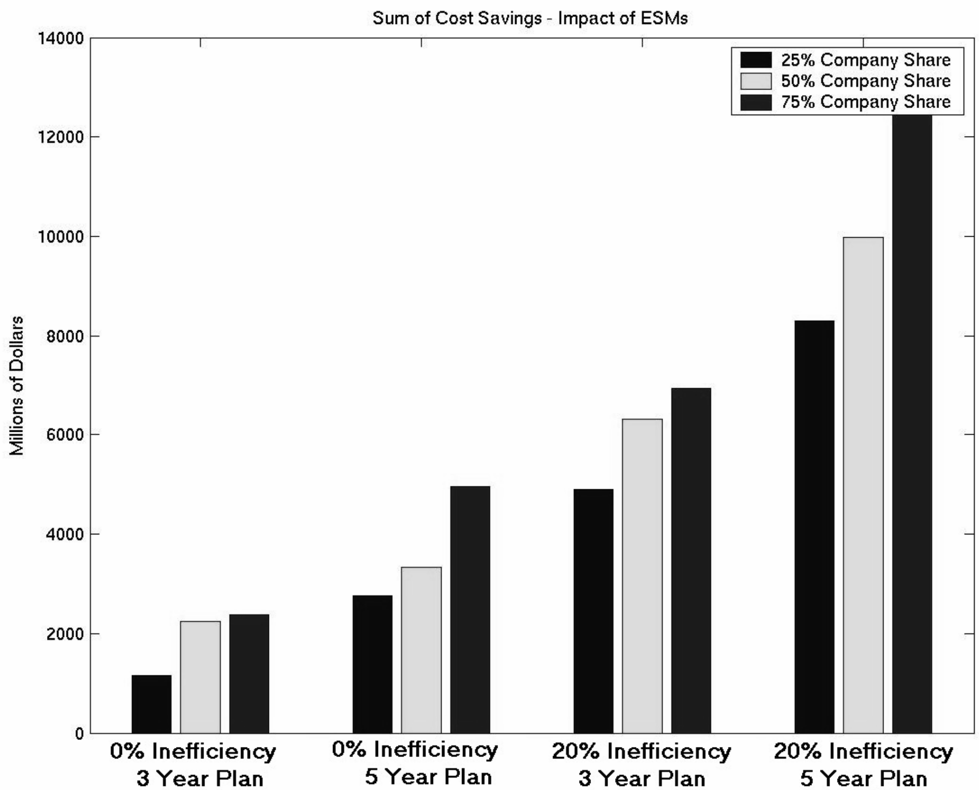
B. Regulatory Scenarios – Impact of plan term and partial externalization on cost savings.



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

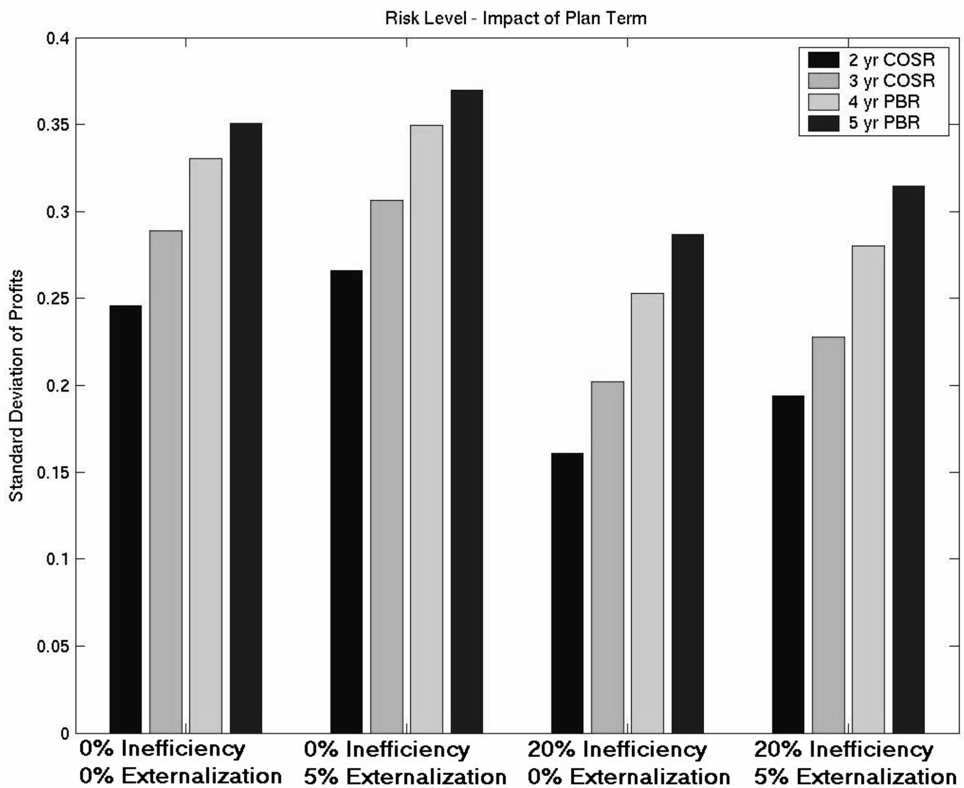
B. Regulatory Scenarios – Impact of ESMs on cost savings.



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

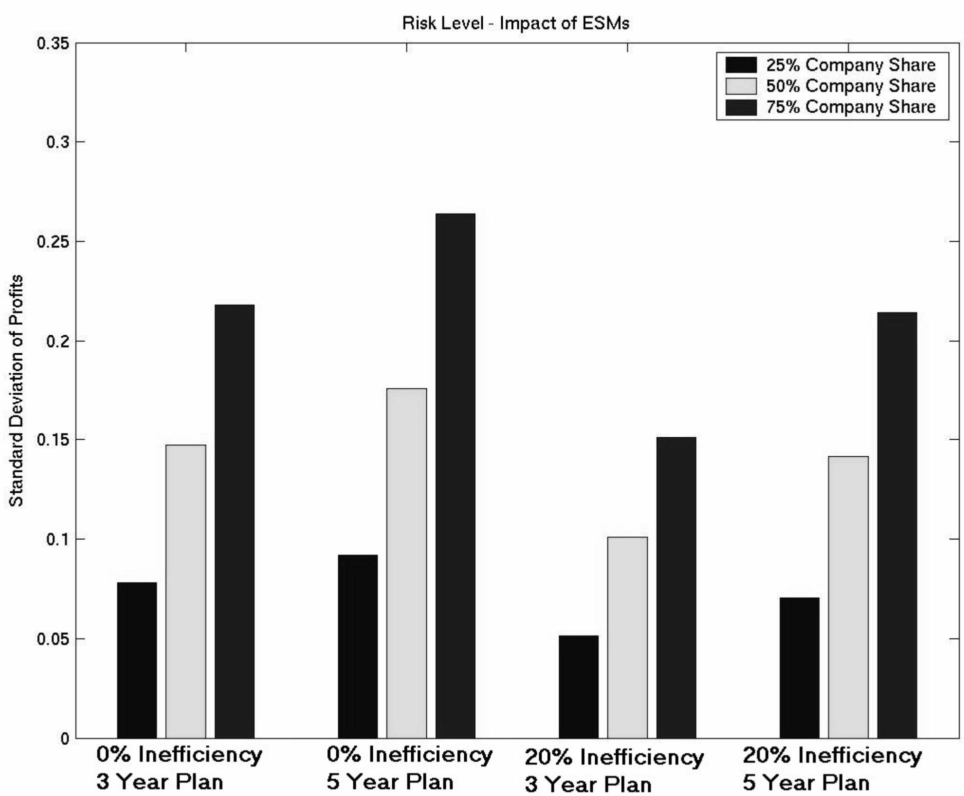
B. Regulatory Scenarios – Impact of plan term and partial externalization on risk.



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

B. Regulatory Scenarios – Impact of ESMs on risk.



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

B. Regulatory Scenarios (cont…) – cost savings

	2 Year Plans		3 Year Plans	
	Impact of Externalization	Cost Savings	Impact of Externalization	Cost Savings
COSR	2 yr 0% extern	461	3 yr 0% extern	983
	2 yr 5% extern	1,468	3 yr 5% extern	1,787
	2 yr 10% extern	1,777	3 yr 10% extern	2,054
	4 Year Plans		5 Year Plans	
	Impact of Externalization	Cost Savings	Impact of Externalization	Cost Savings
PBR	4 yr 0% extern	1,236	5 yr 0% extern	1,435
	4 yr 5% extern	1,863	5 yr 5% extern	1,911
	4 yr 10% extern	2,137	5 yr 10% extern	2,161
	3 Year Plans		5 Year Plans	
	Impact of ESMs	Cost Savings	Impact of ESMs	Cost Savings
PBR Impact of ESMs	3 yr 25% company share	4,897	5 yr 25% company share	8,298
	3 yr 50% company share	6,311	5 yr 50% company share	9,971
	3 yr 75% company share	6,935	5 yr 75% company share	13,632

Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

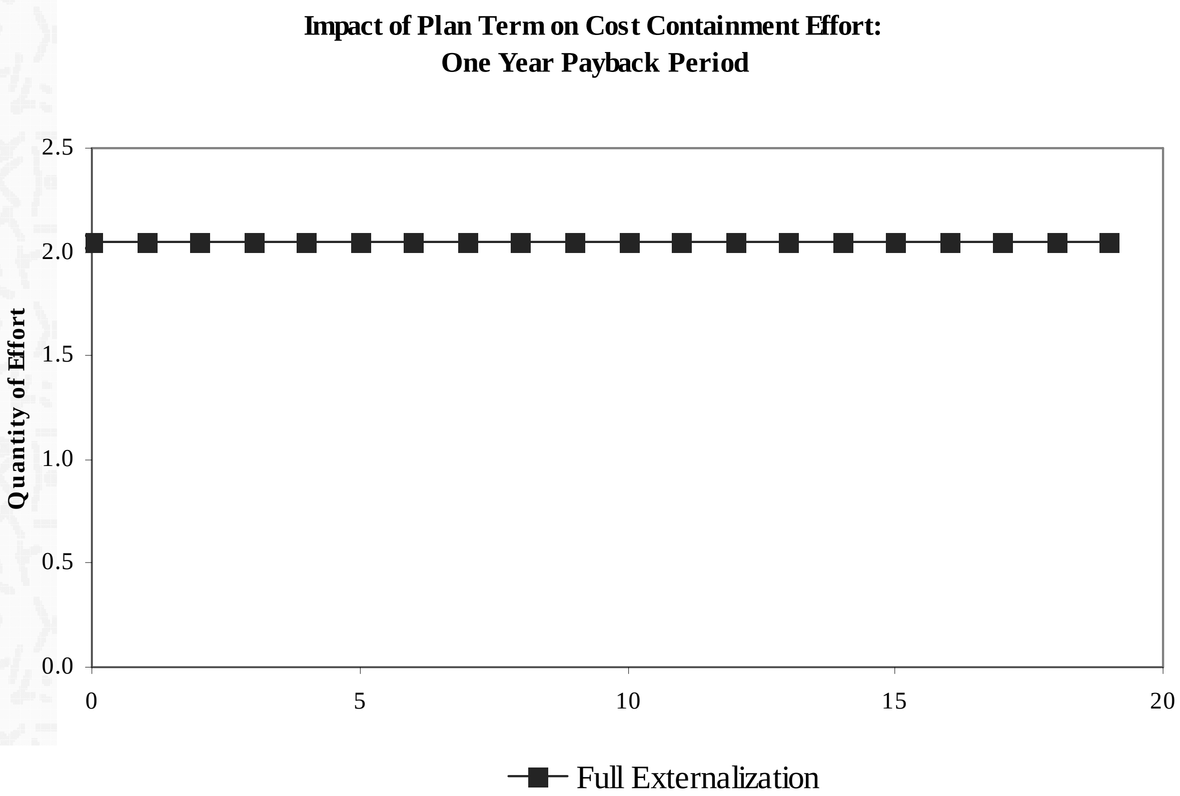
B. Regulatory Scenarios (cont…) – risk level.

	2 Year Plans		3 Year Plans	
	Impact of Externalization	Risk Level	Impact of Externalization	Risk Level
COSR	2 yr 0% extern	16.08%	3 yr 0% extern	20.24%
	2 yr 5% extern	19.40%	3 yr 5% extern	22.79%
	2 yr 10% extern	22.96%	3 yr 10% extern	25.40%
	4 Year Plans		**5 Year Plans**	
	Impact of Externalization	Risk Level	Impact of Externalization	Risk Level
PBR	4 yr 0% extern	25.28%	5 yr 0% extern	28.67%
	4 yr 5% extern	28.02%	5 yr 5% extern	31.48%
	4 yr 10% extern	30.86%	5 yr 10% extern	34.36%
	3 Year Plans		**5 Year Plans**	
	Impact of ESMs	Risk Level	Impact of ESMs	Risk Level
PBR Impact of ESMs	3 yr 25% company share	5.11%	5 yr 25% company share	7.02%
	3 yr 50% company share	10.10%	5 yr 50% company share	14.15%
	3 yr 75% company share	15.12%	5 yr 75% company share	21.41%

Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

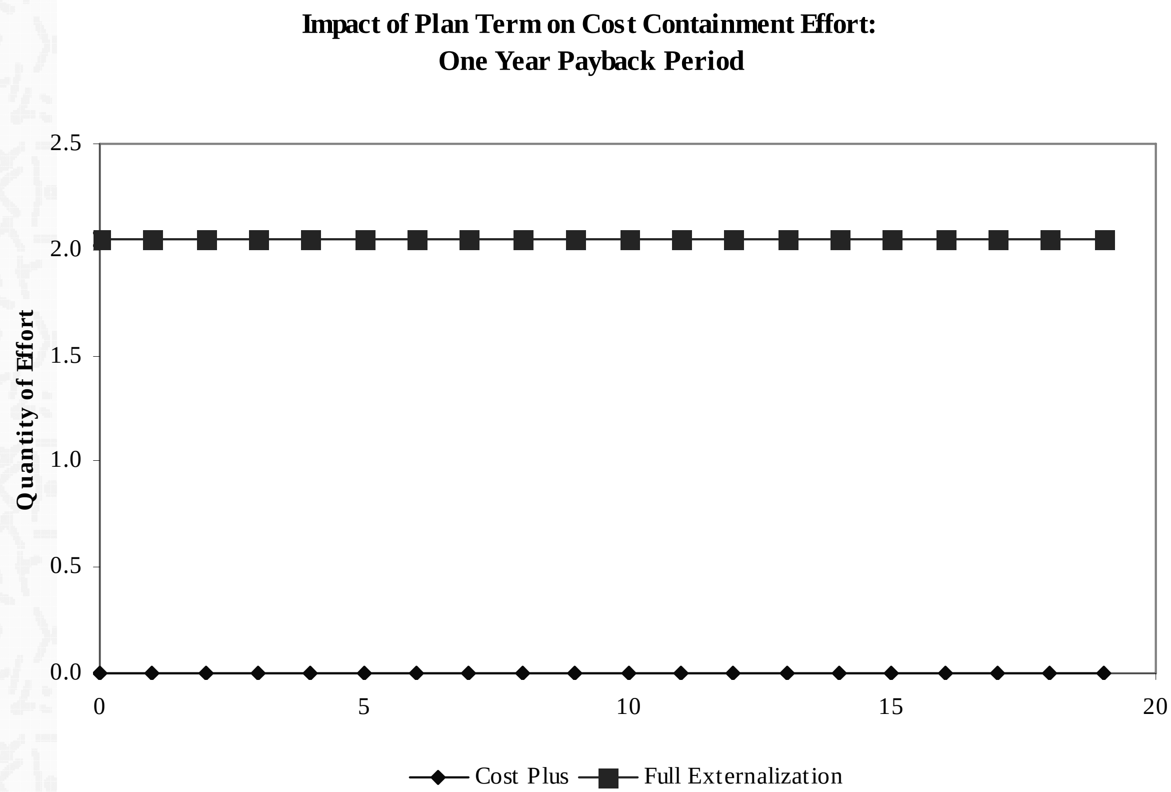
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

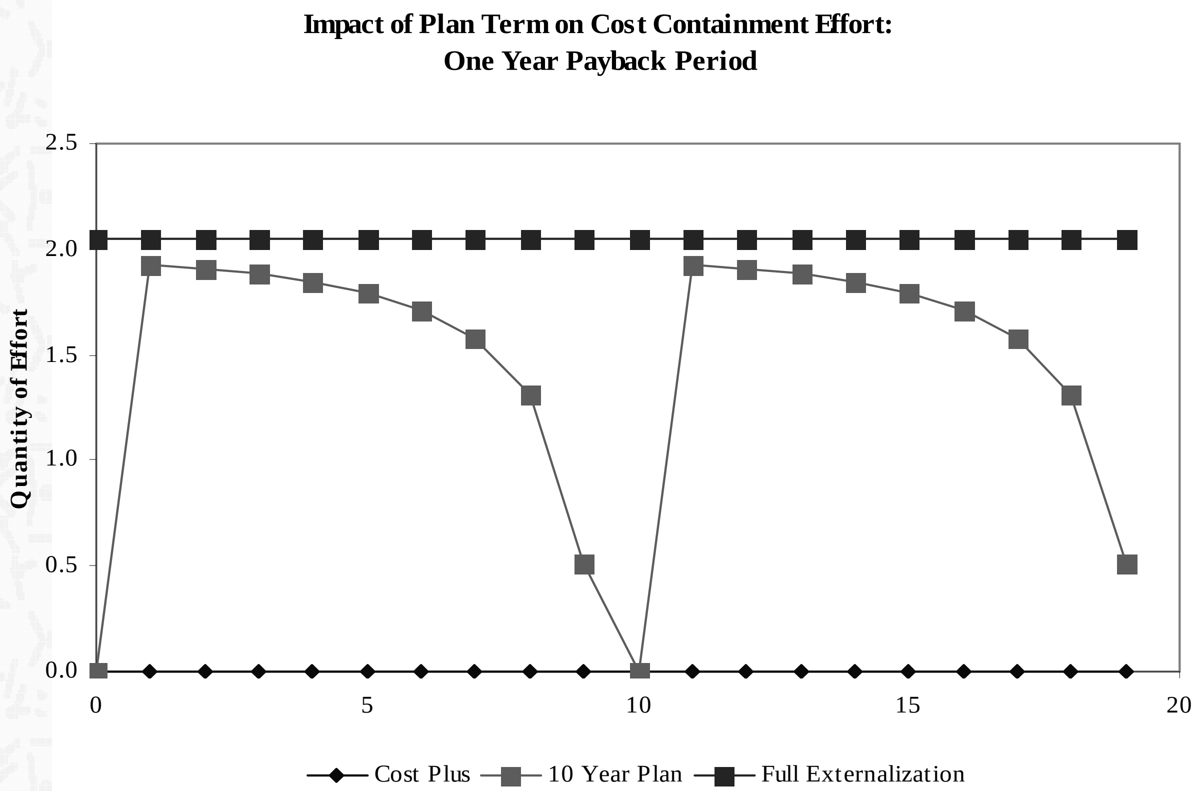
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

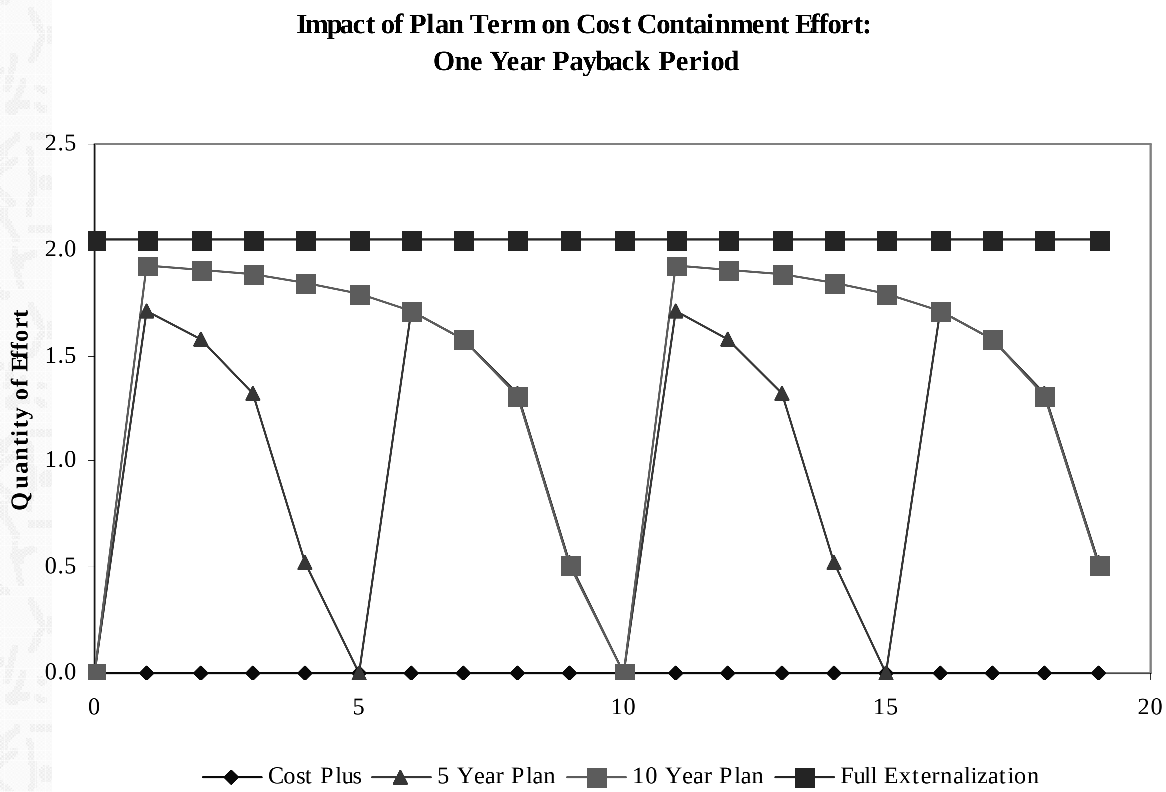
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

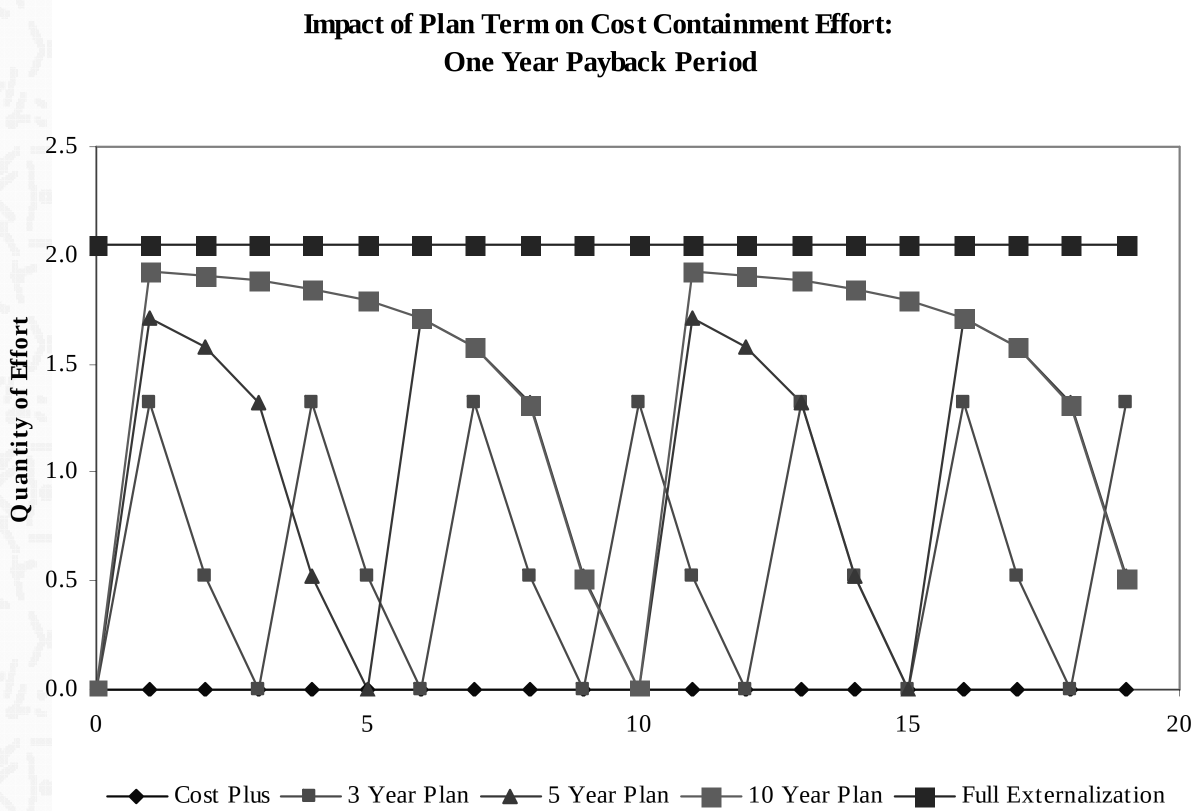
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

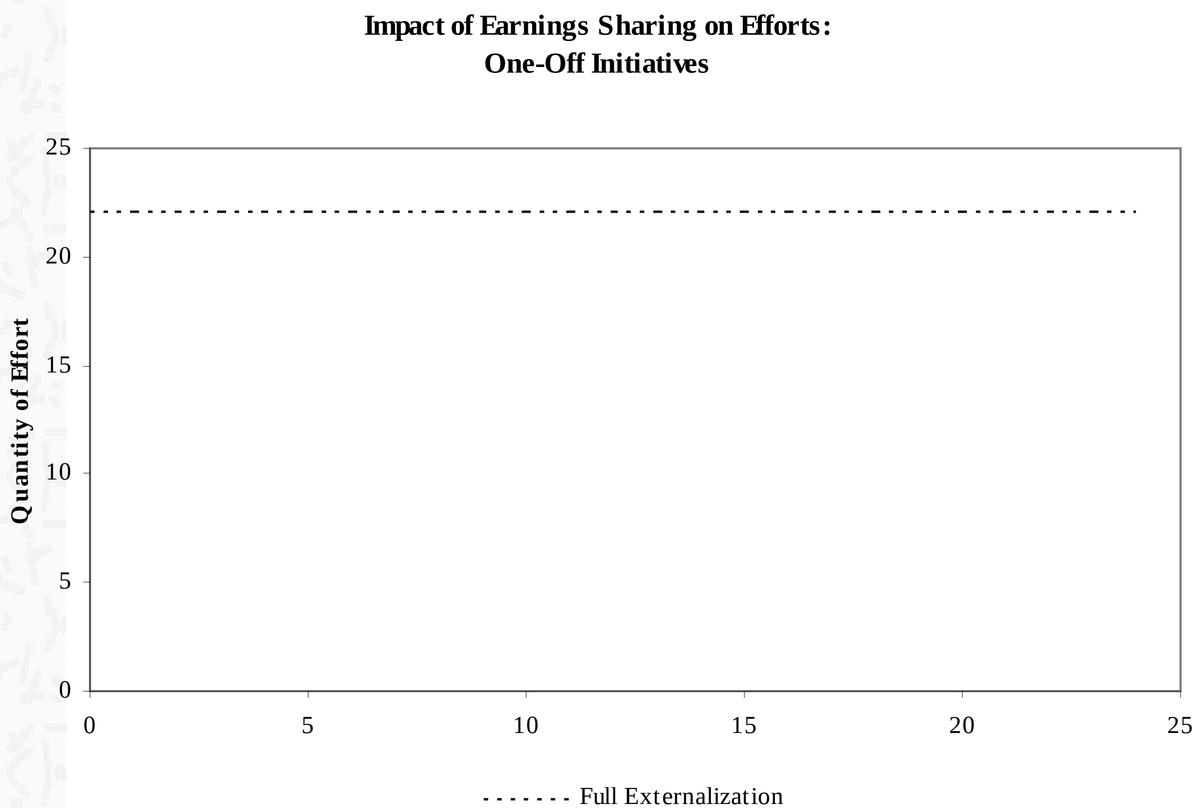
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

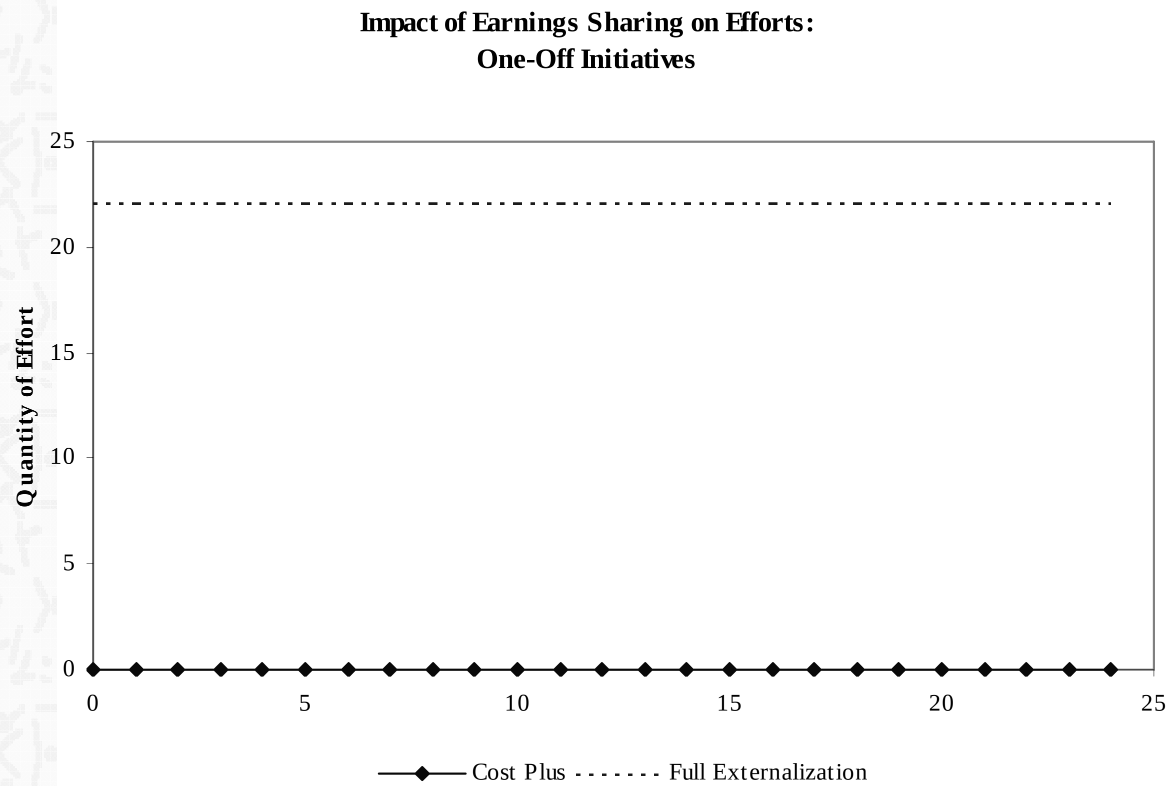
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

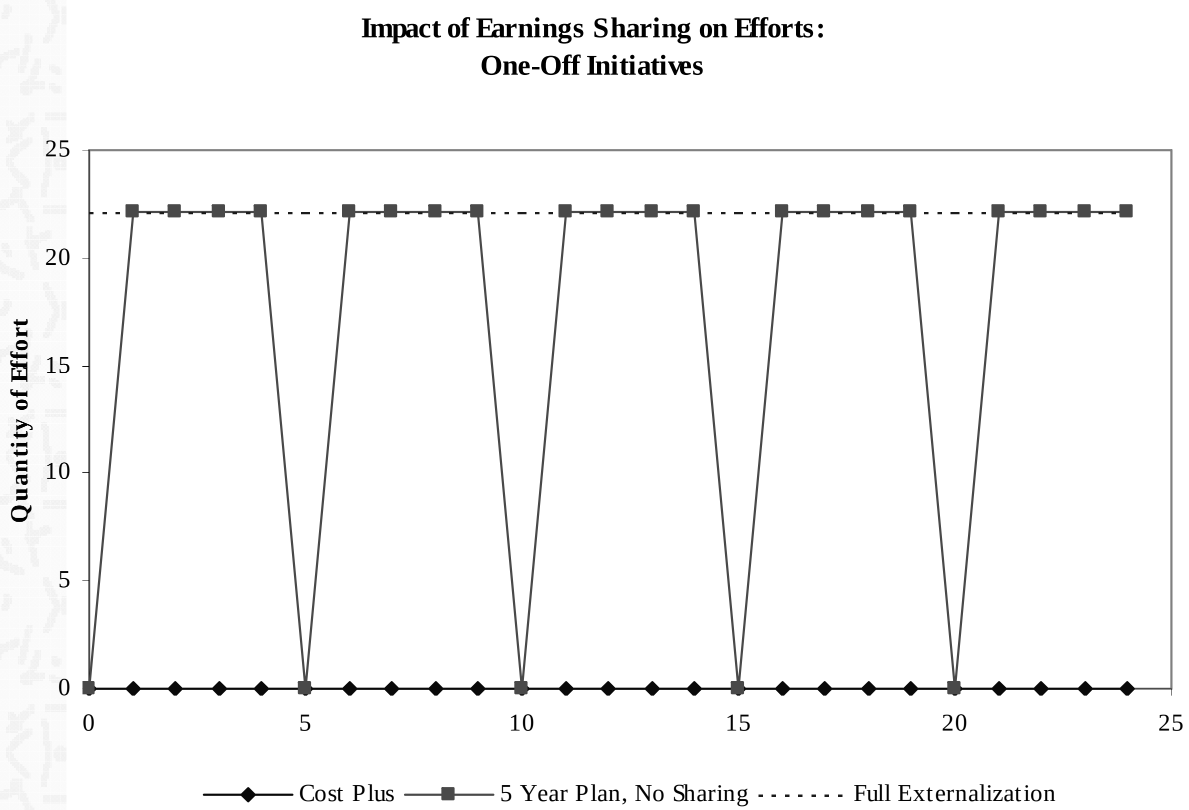
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

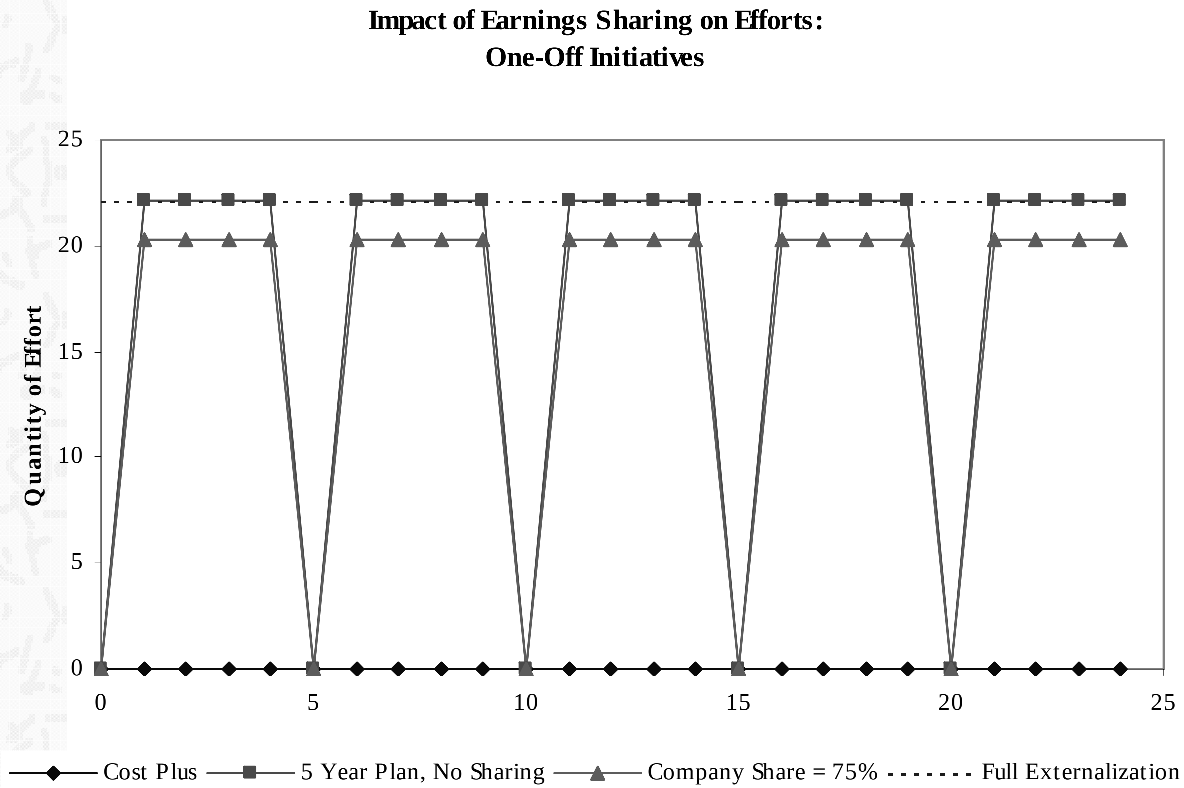
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

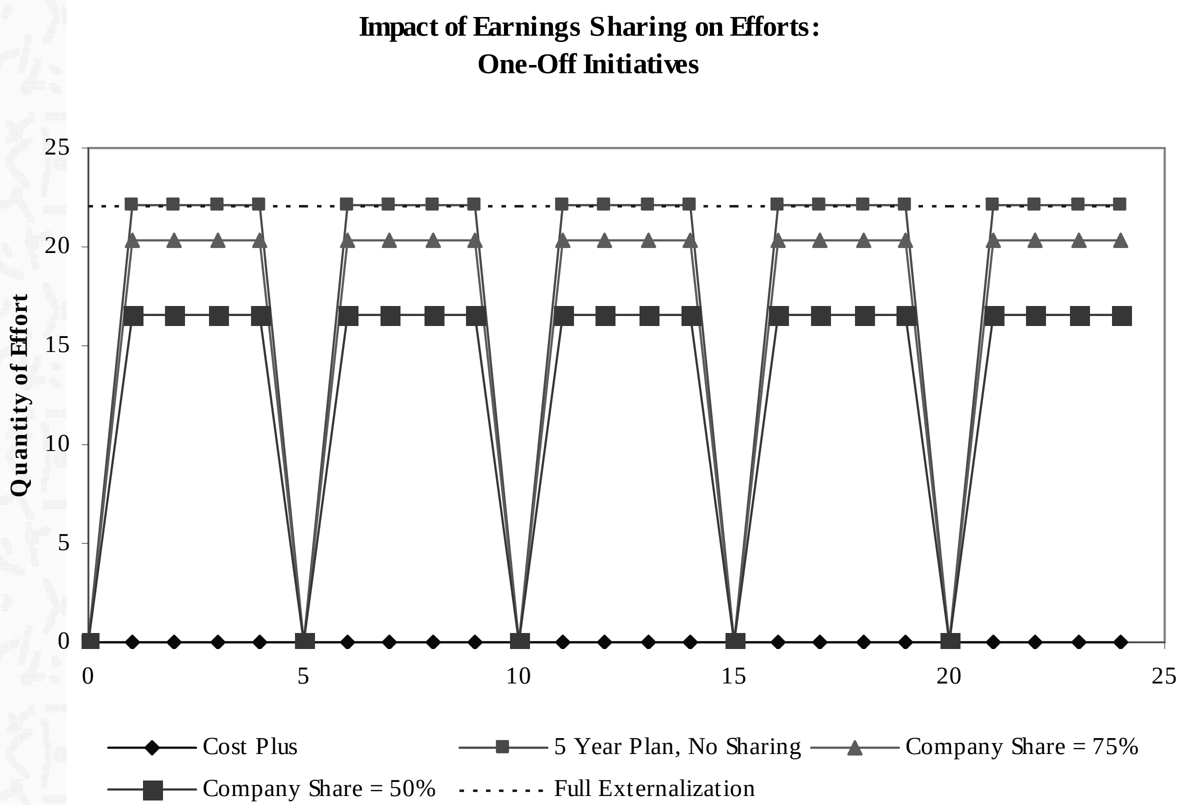
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

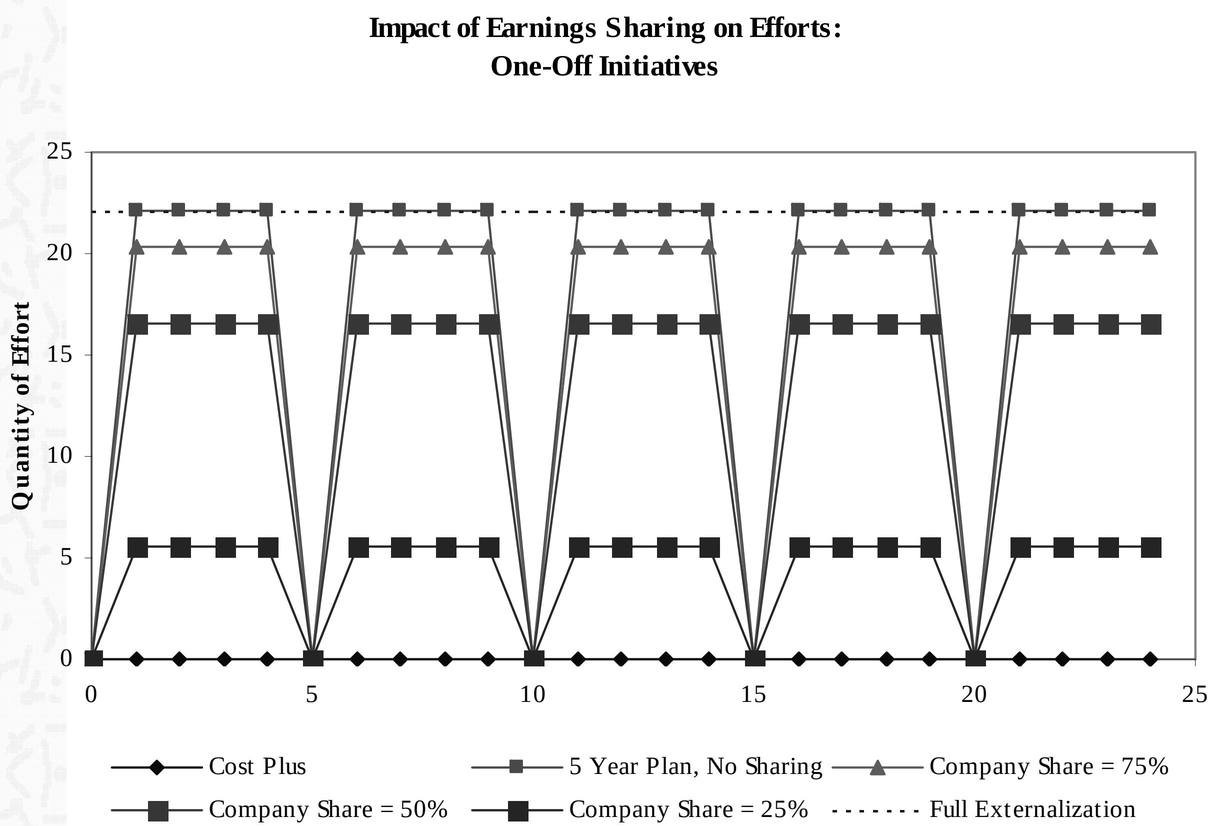
B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

B. Regulatory Scenarios (cont…)



Pacific Economics Group
Economic and Litigation Consulting

IV. PEG's Incentive Power Model (cont…)

C. Some Implications

- Model confirms theoretical conclusions
- Earnings sharing always reduces incentives
- Earnings sharing can lead to worse incentives compared with COSR <u>unless</u> plan term lengthened relative to COSR
- Earnings sharing has more of an impact on permanent than one-off initiatives
- How rates are updated has much more of an impact on permanent than on-off cost reduction initiatives

Pacific Economics Group
Economic and Litigation Consulting

V. Conclusions/Further PEG Work

PEG’s incentive power model very powerful tool

Can examine thousands of regulatory scenarios, input on companies and customers

Can identify what projects will be worthwhile to pursue under different types of regulatory regimes

Can be tailored to individual company/country circumstances

V. Conclusions/Further PEG Work (cont…)

Model can also calculate impact of regulation on

- Customer benefits
- Division of benefits customers and companies

Range of AltReg Options

Larry Kaufmann, *Partner*
Pacific Economics Group, LLC

Alternative Regulation for Electric and Gas Utilities

Boston, MA
June 25, 2007

Pacific Economics Group, LLC
Economic and Litigation Consulting

PBR Taxonomy

Taxonomy of Basic PBR Options

Index Based Mechanisms
- Prices
- Revenues

Freezes
- Prices
- Revenues (per customer)

Earnings Sharing Mechanisms

Benchmark-Based Plans
- Comprehensive
- Service Quality

Rate Indexing

Growth in rates limited by "price cap index" (*PCI*)

$$\text{growth in Rates} \leq \text{growth in } PCI$$

PCI growth determined by pre-established formula

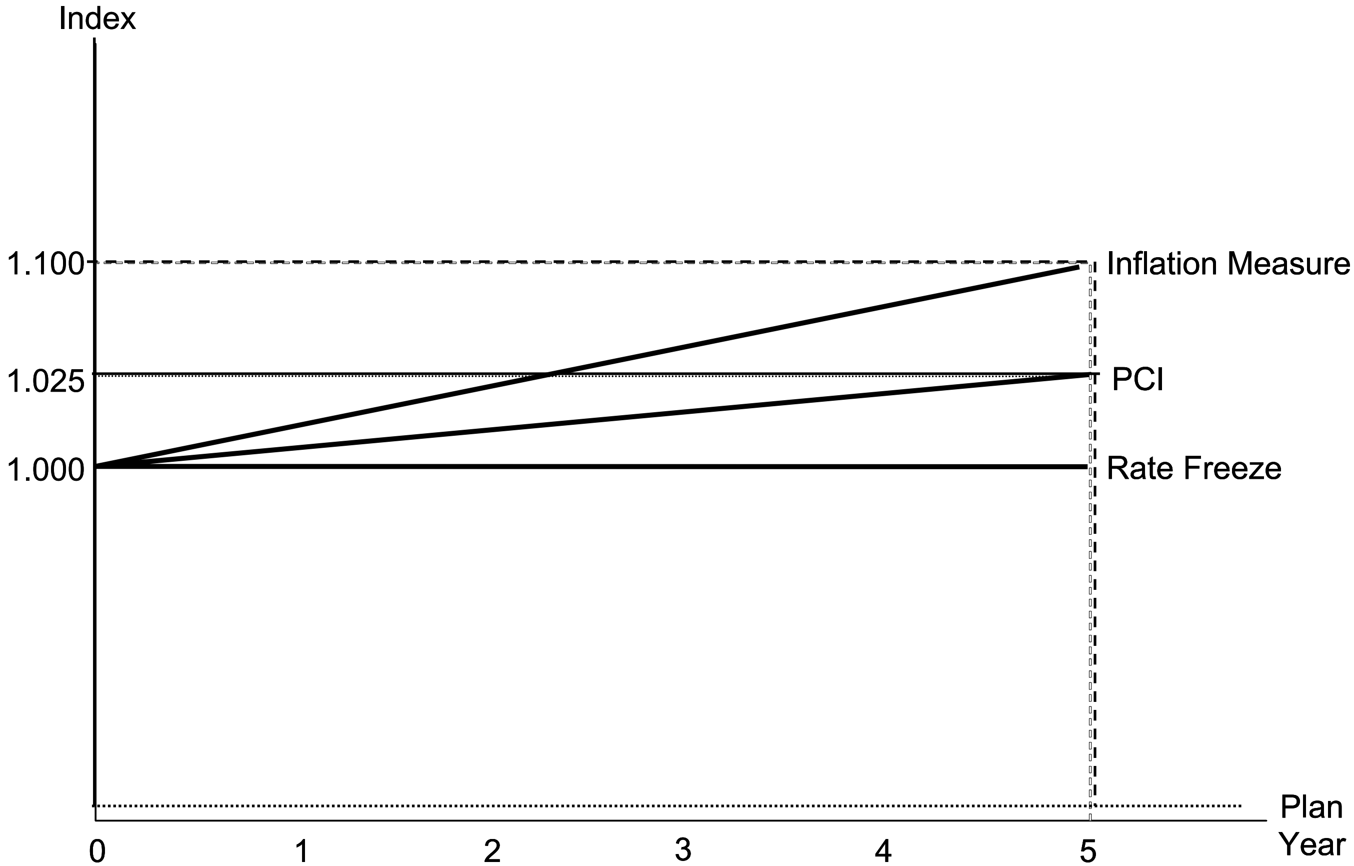
$$\text{growth in } PCI = P - X + Z$$

P = Growth in external "inflation measure"

X = "X-factor" slows PCI growth, ensures customer benefits

>>> In North America, X-factors are usually based on information in industry productivity and input prices

Price Cap Index



Pacific Economics Group, LLC
Economic and Litigation Consulting

Rate Indexing (con't)

Z = "Z-factor" adjusts PCI growth for other external developments

- Changes in government policy (*e.g.* tax rates, undergrounding requirements)
- Change in industry accounting standards
- Force majeure events (*e.g.* hurricanes, ice storms)

Rate Indexing (con't)

Selected U.S. Indexing Precedents for Energy Utilities

Company	Services
Southern California Gas	Gas Distribution
San Diego Gas and Electric	Gas Distribution
Southern California Edison	Electric Distribution
Central Maine Power	Electric Distribution
Bangor Hydro	Electric Distribution
Bangor Gas	Gas Distribution
NSTAR	Electric Distribution
National Grid	Electric Distribution
Boston Gas	Gas Distribution
Bay State Gas	Gas Distribution
Berkshire Gas	Gas Distribution
Blackstone Gas	Gas Distribution

Rate Indexing (con't)

Indexing Pros and Cons

Pro

Can create strong and balanced incentives

Automatic inflation adjustments can provide needed rate relief

Rate adjustments can reflect local input price and productivity trends

>>> Reduced business risk
>>> Longer rate case moratoria, stronger incentives

Con

Complex

Can be implementation controversies & dueling expert witnesses

Pacific Economics Group, LLC
Economic and Litigation Consulting

Freezes

Many Altreg plans have no indexing

- Some plans involve formal rate freezes
    - No rate changes
    - Utilities can file for “Z factor” events
- Legitimate form of AltReg
    - Prices decoupled from costs
      >> better incentives cost control
    - Pre-established plan term
      >> facilities longer-term planning and initiatives

Freezes (con't)

Formal Rate Freezes

Entergy Arkansas	Bundled Power	AR
Edison Sault Electric	Bundled Power	MI
Consumers Energy	Bundled Power	MI
MidAmerican Energy	Bundled Power	IA
Black Hills Light & Power	Bundled Power	SD
Florida Power & Light	Bundled Power	FL
Michigan Transco	Power Transmission	FERC
Int'l Transmission	Power Transmission	FERC
National Grid USA	Power Distribution	MA
National Grid USA	Power Distribution	NY
Atlanta Gas Light	Gas Distribution	CA
Yankee Gas	Gas Distribution	CT

Freezes (con't)

Pros and Cons

<u>No Indexing Con</u>

Energy utilities need rate relief in long run

Commonly achieve "normal" (*e.g.* 0.9%) productivity growth

With input price growth over 2.5%, they need price relief, like most North American companies

Risky No protection against input price volatility

Freezes (con't)

Pros and Cons (con't)

No Indexing Pro

Simple

Avoids "high tech" controversies (*e.g.* TFP measurement)

No "automatic rate increases"

Earnings Sharing Mechanisms

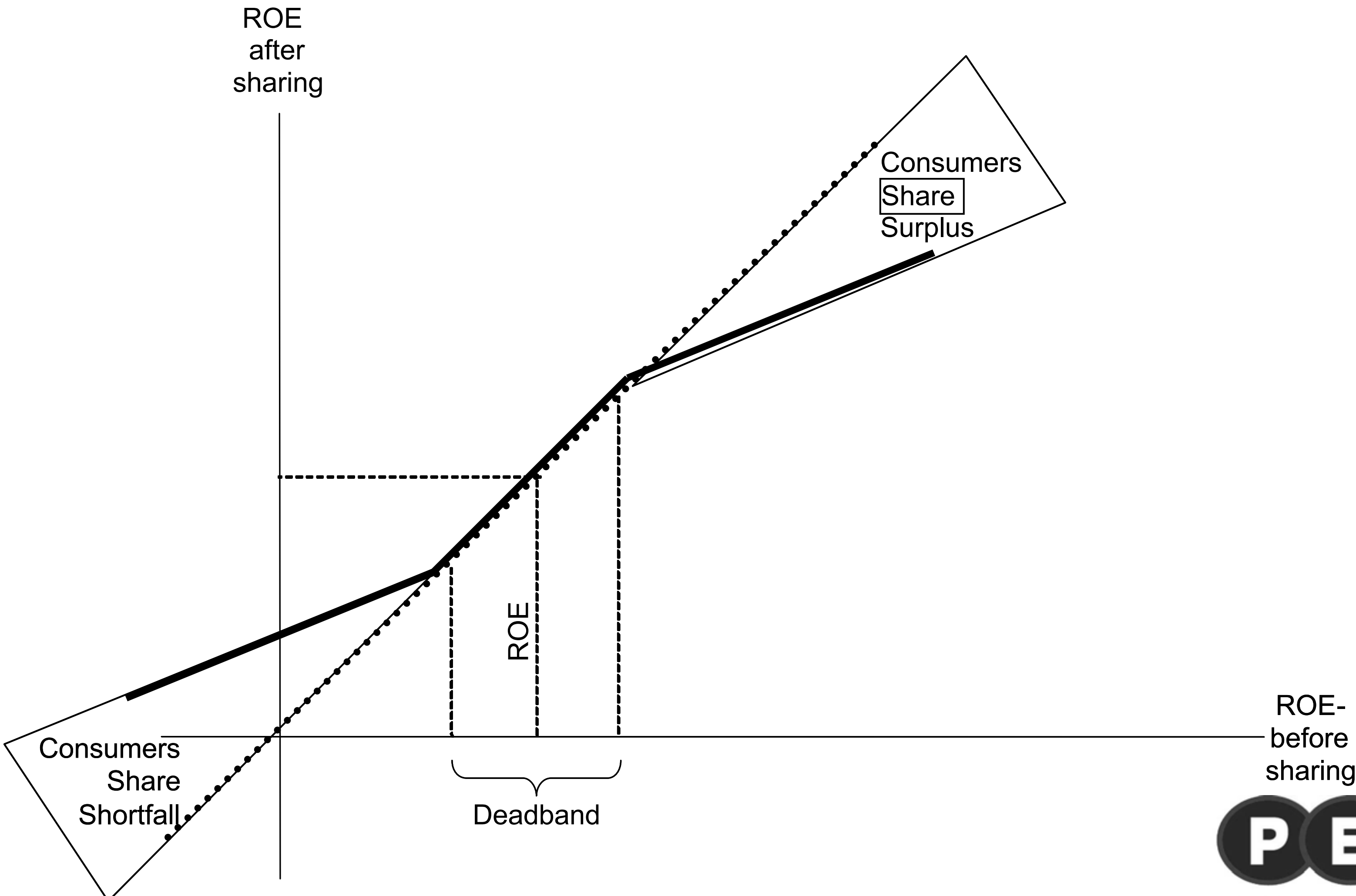
Earnings sharing mechanisms (ESMs) adjust rates automatically for differences between company's *actual* and *target* rate of return.

Rate of return typically ROE

Sharing percentages can differ in different "bands" around target

ROE < 9.5 %	50% company, 50% customers
9.5% < ROE < 13.5 %	100% company
13.5% < ROE	50% company, 50% customers

Earnings Sharing Mechanism (con’t)



Pacific Economics Group, LLC
Economic and Litigation Consulting

Earnings Sharing Mechanism (con't)

ESM Pro:

Transparent alignment of shareholder and customer interests

>>> Company & customers clearly share benefits of better performance

Benefits shared *as realized*

Customers benefit *earlier*

Reduces risk

Discourages extremely high or low earnings

Pacific Economics Group, LLC
Economic and Litigation Consulting

Earnings Sharing Mechanism (con't)

Earnings Sharing Con:

Weakens performance incentives *if no plan extension*

e.g. Company keeps 50% of benefits, not 100%

Earnings calculations can be controversial absent defined mechanism

Customers disappointed when earnings not in sharing range

Earnings Sharing Mechanism (con't)

Earnings Sharing Precedents

Energy

- Common in approved North American plans
- Excluded from several recent plans (e.g. AmerenUE)
- Rare overseas

Telecom

- Common in early plans
- Rare in recent plans

Benchmark-Based PBR

Benchmark-based PBR has the following "basic ingredients"

<u>Activity Variables</u>	Variables that measure company activities (*e.g.* Unit Cost)
<u>Benchmarks</u>	External standards of comparison for activity variables (*e.g.* Unit $\text{Cost}^{\text{Peer}}$)
<u>Evaluation Mechanism</u>	Method for comparing activity variables to benchmarks (*e.g.* $\text{Cost}^{\text{Company}}$-$\text{Cost}^{\text{Peer}}$)

Benchmark-Based PBR (con't)

- A good benchmark takes account of <u>external business conditions:</u>
  - Business conditions beyond the control of *utilities* that influence their activities

- Examples
  - Scale of service *e.g.* MWh delivered, # customers
  - Mix of services *e.g.* residential, commercial, industrial
  - Input prices *e.g.* labor and capital services
  - Urbanization
  - Terrain

Benchmark-Based PBR (con't)

Benchmarks are typically determined using

- Company's own historical performance
  - The most common approach
  - Sometimes includes "stretch" goals
- Peer performance
  - Industry measures
  - Peer group "yardsticks"

Benchmark-Based PBR (con't)

Two basic types of benchmark PBR

- Comprehensive: focused on a broad-based activity variable or variables
- Partial: focused on a more narrow measure of performance

Benchmark-Based PBR (con't)

Comprehensive Benchmark Plan Precedents

Unit Cost Yardsticks/Peer Comparisons

- Niagara Mohawk Power
- NM Gas
- NYSE&G

Price and Service Quality Indicators

- Mississippi Power "PEP"
- Xcel Energy/North Dakota "PLUS"

Benchmark-Based PBR (con't)

Evaluation: Comprehensive Benchmark PBR

Pros
- Can create strong incentives
- Potentially creates balanced incentives

Cons
- Complexity
- Typically doesn't increase operating flexibility
- May not eliminate need for supplemental rate adjustments

Benchmark-Based PBR (con't)

Non-Comprehensive/Targeted Benchmark Plans

- Service Quality >> most common
- Fuel (*e.g.* natural gas) procurement
- Demand-side management
- Generator performance
- O&M costs

Benchmark-Based PBR (con't)

Evaluation: Non-comprehensive Benchmark PBR

<u>Pros</u>

- Can be very effective in improving performance in targeted areas

<u>Cons</u>

- Doesn't affect non-targeted areas, may create unbalanced incentives
- Complexity in determining appropriate penalty/reward structure
- Some plans controversial

IGUA #14

INTERROGATORY

Ref: PEG Report, p. (iii)
Issue No.: 3.1
Issue: How should the X factor be determined?

PEG states that the higher X factor for EGD is chiefly due to its greater opportunities to realize scale economies. Please produce and explain the factors and evidence considered by PEG in coming to this conclusion.

RESPONSE

Please see our response to IGUA Exhibit R-PEG Tab 5 Schedule 12 for a discussion of the scale economy evidence.

Witness: Mark Lowry

IGUA #16

INTERROGATORY

Ref: PEG Report, p. (iv)
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

PEG states that, when an RCI is used, a balancing account commonly ensures that the allowed revenue requirement is exactly recovered. Please identify the various categories of costs which are commonly included in such a balancing account:

RESPONSE

Balancing accounts used in revenue decoupling mechanisms are typically designed to recover the revenue requirement for non-energy base rate inputs. These are the inputs required for gas transmission, distribution, storage, customer, administrative, and general services.

Witness: Mark Lowry

IGUA #20

INTERROGATORY

Ref: PEG Report, p. (vii)
Issue Nos.: 3.1 and 3.2
Issue: 3.1 How should the X factor be determined
3.2 What are the appropriate components of an X factor?

PEG states that no evidence has been brought to their attention concerning the recent operating efficiency of EGD or Union, and accordingly, PEG has no basis for adjusting the X factor for this consideration. Were EGD and Union given an opportunity to provide evidence relevant to the determination of a stretch factor? If the answer is yes, please explain the opportunities provided to EGD and/or Union and produce all related correspondence.

RESPONSE

PEG believes that utilities have an opportunity to file evidence documenting the superiority of their performance whenever they file in support of a rate case or an IR plan. Such evidence is always germane. Enbridge twice retained Dr. Lowry to file benchmarking studies in prior rate cases. It was also presumably cognizant of our views of the relevance of benchmarking in stretch factor determination at the time it prepared its evidence for this IR proceeding.

Witness: Mark Lowry

IGUA #32

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, page 17 of 48
Issue No.: 12.3
Issue: 12.3 Changes in Rate Design
12.3.1 What should be the criteria for changes in rate design?
12.3.2 How should the change in the rate design be implemented?
12.3.3 What should be the information requirements for a change in rate design?

Union claims that it should have the ability to adjust the Fixed Monthly Charge and the Variable Charge on a revenue neutral basis annually. Union claims that with the ability to adjust the Fixed Monthly Charge and the Variable Charge on a revenue neutral basis, there would be no need to adjust the fixed monthly charge as part of the Price Cap formula.

a) Is it appropriate to adjust the Fixed Monthly Charge and Variable Charge during the IR term? Please provide an explanation.

b) Would these adjustments impact Union's business risks?

c) If Union is provided with the ability to adjust the Fixed Monthly Charge and the Variable Charge during the term of the IR period, would there be a need to adjust the PCIs or RCIs calculated by PEG? Please explain.

RESPONSE

a) Such adjustments are reasonable when the base year rates do not properly reflect the differential impacts of customer and volume growth on cost. PEG cannot comment on the appropriateness of the current Union's rate design.

b) Higher fixed charges would reduce Union's business risk.

c) Yes. PEG calculated PCIs and RCIs on the premise that no rate redesigns occur. If rate redesigns do occur, it is likely that they will increase the share of revenue which is drawn from fixed charges and less revenue from

Witness: Mark Lowry

volumetric charges. Since the number of customers grows more rapidly than volumes this will bolster future revenue

IGUA #39

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 1, pp. 8 to 10 of 37
Issue No.: 3.1
Issue: How should the X factor be determined?

EGD provides evidence in Tables 3, 4 and 5, as well as in the corresponding text about its Output Quantity Index, Input Quantity Index, and Historical Cost Weighted TFP:

a) Did PEG have access to this information when it prepared its report?

b) If the answer to (a) is no, did PEG request this information from EGD?

c) Does this information alter PEG's opinion on the appropriate X factor to be used in the Revenue Cap Index ("RCI") and PCI applicable to EGD?

RESPONSE

a) The EGD calculations appear to use some of the data series that PEG used in its productivity research. However, some new data may have been used.

b) Yes. PEG asked for this information in a data request.

c) No. The X factor should, after all, be based on external data since this approach generates stronger performance incentives and the available external data have been found to be relevant. Estimates of the TFP trend of Enbridge should be used to gauge the reasonableness of results from external sources. However, we have shown that the TFP growth of Enbridge over the 2000-2005 period has been slowed by extremely slow O&M productivity growth. Specifically, the O&M productivity growth of Enbridge averaged -0.70% during this period. This compares to a 1.31% trend for Union and a 2.23% trend for the U.S. sample. Enbridge witnesses have not provided an able defense of this striking disparity. It follows that *the fact that* *the TFP growth of Enbridge from 2000 to 2005 was well below its target isn't evidence that the target is inappropriate. It is instead evidence of the merit of using TFP indexes based on external data in X factor design.* The TFP growth of Union is remarkably similar to its target and it is not at all clear why the business conditions of Enbridge should not make similar productivity growth achievable.

Regarding the specifics of the TFP index discussed by witness Lister on p. 9 of his testimony, the striking difference between the -0.60 trend that he reports and the 1.88% target proposed by PEG is that Enbridge uses a *revenue* weighted TFP index rather than the elasticity-weighted index that PEG used in its effort to isolate the average use effect. A revenue weighted output index computed using PEG's method (including GD capital costing) would have a trend of only 0.11.

The residual 71 [11+(-60)] basis point difference between the Enbridge and PEG calculations is due chiefly to the Enbridge approach to weather normalization. This approach may be satisfactory for rate-setting under the company's recent schedule of annual rate cases but is unsatisfactory for X factor calibration because of its backward looking recognition of average use trends. PEG's method, which is similar to Union's, is more appropriate for PCI calibration.

In summary, then, the TFP index calculated by Enbridge has limited relevance to this proceeding because it reflects unexplained slow O&M productivity growth and uses an inappropriate approach to weather normalization. It is a poor choice as a TFP target for Enbridge when reasonable external targets are available. If the Board wishes to use an Ontario-specific TFP target for Enbridge, it should choose the 1.87% trend of Union.

IGUA #40

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 1, page 25 of 37
Issue No.: 3.1
Issue: How should the X factor be determined?

EGD has identified what it claims are viable alternatives for establishing the productivity target which include:

(a) Use of the California Department of Rate Payer Advocates replicated PEG model presented in July 2007 for the U.S. as a whole, adjusted for the Canadian-U.S. productivity gap;

(b) Use of the California Department of Rate Payer Advocates replicated PEG model presented in July 2007 for the Northeast Sector, adjusted for the Canadian-U.S. productivity gap.

(i) Does PEG agree that either of these adjusted models are viable alternatives for establishing the productivity target for EGD? If not, why not?

RESPONSE

No. A peer group for Enbridge should consist of utilities facing similar drivers of TFP growth. As discussed informally on pp. 6 and 7 of PEG's June report and explained on detail in IGUA Q40 Appendix A, PEG used mathematical theory and econometric research, which provided a rigorous basis for identifying the drivers of TFP growth and choosing peer groups.

Here is a more formal treatment that is consistent with our derivation of the ADJ factor that is discussed on pp. 93 and 94 of the June report. The starting point for the analysis is the assumption that the actual cost incurred by a firm is the product of its minimum total cost, C^*, and a term, η, that may be called the inefficiency factor.

$$C = C^* \cdot \eta. \tag{A-1}$$

The inefficiency factor indicates how high the actual cost of a firm is above the minimum attainable level. Equation (A-1) implies that the instantaneous growth rate of total cost is the sum of the growth rates of minimum total cost and the inefficiency factor. [1]

$$\dot{C} = \dot{C}^* + \dot{\eta}. \tag{A-2}$$

It is a basic result of economic theory that given competitive a well-behaved production technology, the minimum total cost of an enterprise is a function of various input prices (***W***), output quantities (***Y***), and variables that measure miscellaneous other business conditions (***Z***). The resultant cost function can be represented mathematically as

$$C^* = g(\boldsymbol{W}, \boldsymbol{Y}, \boldsymbol{Z}). \tag{A-3}$$

The elasticity of cost with respect to each output variable Y_i is denoted by ε_{Y_i}. The other elasticities and business condition variables are denoted analogously.

Total differentiation of Equation (A-3) with respect to time reveals that

$$\dot{C}^* = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_h \varepsilon_{Z_h} \cdot \dot{Z}_h + \sum_j \varepsilon_{W_j} \cdot \dot{W}_j \right) + \dot{g}. \tag{A-4}$$

The growth rate of minimum total cost can be seen to be the sum of two terms. The first is the sum of the products of the growth rates of the business condition variables and their corresponding cost elasticities. The second is the proportional shift in the cost function ($\dot{g}$).

Shephard's lemma holds that the derivative of minimum total cost with respect to the price of an input is the optimal input quantity. The elasticity of minimum total cost with respect to the price of each input, *j*, then equals the optimal share of that input in minimum total cost (sc_j^*). Equation (A-4) may therefore be rewritten as

$$\begin{aligned} \dot{C}^* &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_h \varepsilon_{Z_h} \cdot \dot{Z}_h + \sum_j sc_j^* \cdot \dot{W}_j + \dot{g} \\ &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_h \varepsilon_{Z_h} \cdot \dot{Z}_h + \dot{W}^* + \dot{g}. \end{aligned} \tag{A-5}$$

The third term on the right-hand side of (A-5) is the growth rate of an input price index, which we will denote by W^*. The growth rate of W^* is a weighted average of the growth rates of the price subindexes for each input category. The optimal (cost-minimizing) cost shares serve as weights rather than the actual cost shares of the utilities. We will call W^* the optimal input price index. Assume for simplicity that it is approximately equal to growth in a company's actual input price index, $\dot{W}$.

Let us now define the growth rate of a TFP index (TFP^E) to be the difference between the growth rates of a cost elasticity output quantity index (Y^E) and an input quantity index (X). Formally

[1] All growth rates in this discussion are assumed to be instantaneous.

$$T\dot{F}P^{E} \;=\; \dot{Y}^{E} - \dot{X}\;. \tag{A-6}$$

The growth rate of the input quantity index is known to be the difference between the growth rates of cost and the (actual) input price index (*W*).

$$\dot{X} \;=\; \dot{C} - \dot{W} \tag{A-7}$$

Equations (A-5) - (A-7) imply that

$$\begin{aligned}
T\dot{F}P^{E} &= \dot{Y}^{E} - \left(\dot{C} - \dot{W}\right) \\
&= \dot{Y}^{E} - \left[\left(\sum_i \varepsilon_{Y_i}\cdot \dot{Y}_i + \sum_h \varepsilon_{Z_h}\cdot \dot{Z}_h + \dot{W} + \dot{g} + \dot{\eta}\right) - \dot{W}\right] \\
&= \dot{Y}^{E} - \left[\left\{\sum_i \varepsilon_{Y_i}\left[\left(\sum_i \frac{\varepsilon_{Y_i}}{\sum_i \varepsilon_{Y_i}}\right)\cdot \dot{Y}_i\right] + \sum_h \varepsilon_{Z_h}\cdot \dot{Z}_h + \left(\dot{g} + \dot{\eta}\right)\right\}\right] \\
&= \dot{Y}^{E} - \left[\left\{\sum_i \varepsilon_{Y_i}\left[\dot{Y}^{E}\right] + \sum_h \varepsilon_{Z_h}\cdot \dot{Z}_h + \left(\dot{g} + \dot{\eta}\right)\right\}\right] \\
&= \dot{Y}^{E} - \left[\left\{(\sum_i \varepsilon_{Y_i} - 1)\left[\dot{Y}^{E}\right] + \dot{Y} + \sum_h \varepsilon_{Z_h}\cdot \dot{Z}_h + \left(\dot{g} + \dot{\eta}\right)\right\}\right] \\
&= \left[\left\{(1 - \sum_i \varepsilon_{Y_i})\left[\dot{Y}^{E}\right] - \sum_h \varepsilon_{Z_h}\cdot \dot{Z}_h - \left(\dot{g} + \dot{\eta}\right)\right\}\right]
\end{aligned} \tag{A-8}$$

The growth rate of the TFP index has been decomposed theoretically into four terms. The first is the **scale economy effect**. Returns to scale are realized to the extent that incremental scale economies are available and output quantity grows. Incremental scale economies exist if the sum of the cost elasticities with respect to the output variables is less than 1.

The second term measures the effect on TFP growth of growth in the values of the Z variables. We will call this the **other business condition effect**. If the cost elasticity of a given Z variable, *h*, is positive (negative), an increase in the value of the variable will decelerate (accelerate) TFP growth.

The third term measures the effect on TFP growth of the proportional shift in the cost function. It may be called the **technological change effect**. The cost function will shift downward (upward) if cost falls (rises) at given values of the business condition variables. A downward (upward) shift in the cost function will accelerate (decelerate) TFP growth.

The fourth term measures the effect on TFP growth of a change in the inefficiency factor. We will call this the **inefficiency effect**. A decline (increase) in the inefficiency factor will accelerate (decelerate) TFP growth.

Equation (A-8) reveals that TFP growth depends on the *growth rates* of outputs and other business condition variables and not on their *levels.* It makes sense, then, to search for peers facing similar growth rates in business conditions.

PEG used Equation (A-8) and the econometric estimates of cost elasticities which it developed for the Board to prepare peer groups for Enbridge and Union rigorously. The econometric research readily provides the estimates needed for the scale economy effect and the parametric trend effect. In principle, other business condition effects could also be included in the model. The econometric research identified three other business conditions: number of electric customers, % of line miles that are not cast iron, and the presence or absence in the service territory of an urban core. With regard to these

- The value of the urban core variable doesn't change.
- Enbridge and Union don't have electric customers
- The estimate on the cast iron variable suggests that reducing cast iron *lowers* cost rather and does not *raise* cost as Enbridge suggests.

Feeling that the cast iron effect might be different in the short run PEG chose not to use this variable in our TFP target research. Since the parametric change effect is similar for all companies and the other two business conditions are not germane, the research suggested that similarity in the scale economy effect was the sole basis for choosing peers. Since Enbridge and Union are experiencing brisk customer growth, the peers will tend to be companies that also have brisk customer growth.

In contrast to this scientific approach to peer group selection, Enbridge witness Carpenter recommended on p. 22 of his evidence

> a much simpler and easier to understand and replicate approach to the selection of a per group for EGDI. This would involve the identification of the four or five key factors which contribute to costs and scale economies in gas distribution.

The universe of utilities from which peers would be chosen using these criteria would be restricted to the northeast U.S. Carpenter presents data on these business conditions in Table 4 on p. 23 of his evidence. In addition to the *ad hoc* character of Carpenter's proposed approach, it turns out that Enbridge is *not* similar to the typical Northeast utility in most of the measures chosen. Most importantly, Enbridge is much larger than the typical northeast utility and has a much more rapid pace of output growth. This is important since it is these two variables that have some bearing on the scale economy effect. Note also that Enbridge has far less cast iron than the typical northeast utility.

The attached table labeled “IGUA Q40 Attachment 1” presents an objective comparison of the scale economy effect and other relevant data for three alternative peer groups: the PEG peer group, a northeast peer group, and the full U.S. sample. It can be seen that the scale economy effect of the PEG peer group is the most similar to that of Enbridge whereas that of the Northeast peer group is the *least* similar. This suggests that a Northeast peer group would be a poor choice. A full U.S. sample peer group would be a better choice but still suboptimal since the U.S. industry as a whole is not experiencing the rapid customer growth of Enbridge.

The table also displays the average TFP growth rates of the companies in the three peer groups. The difference between the average TFP growth rates of the PEG and Northeast peer groups is striking. The Northeast peer group has very slow TFP growth because of its slow output growth. Yet Enbridge has very rapid output growth.

The results of this discussion reveal that the peer group recommended by PEG has a solid foundation in empirical research and mathematical reasoning. The approach recommended by Enbridge is, in contrast, nonsensical and self-serving and should carry no weight in this proceeding.

CHOOSING TFP PEERS FOR ENBRIDGE: COS

Company	TFP	2004 Number of Customers	Sum of Elasticities [E]	Elasticity Weighted Output [dYe]	Expected Scale Economies = (1-[E]) x [dYe]
Enbridge	**0.71%**	**1,529,297**	**0.772**	**2.83%**	**0.65%**
Arithmetic Sample Average [1,2]	**1.29%**	**883,827**	**0.889**	**1.50%**	**-0.51%**
Difference from Enbridge	**0.58%**	**(645,470)**	**0.117**	**-1.33%**	**-1.16%**
PEG Peer Group					
Atlanta Gas Light	**1.45%**	1,532,615	0.857	1.59%	0.23%
Consumers Power	**0.82%**	1,690,874	0.778	1.42%	0.31%
Northern Illinois Gas	**1.58%**	2,092,607	0.749	1.56%	0.39%
Northwest Natural Gas	**2.09%**	586,461	0.934	3.69%	0.24%
Southwest Gas	**2.90%**	1,550,509	0.915	4.60%	0.39%
Washington Gas Light	**2.61%**	980,686	0.771	3.03%	0.69%
Washington Natural Gas	**1.04%**	661,739	0.866	3.28%	0.44%
Mountain Fuel Supply	**2.16%**	777,555	0.867	2.77%	0.37%
New Jersey Natural	**1.83%**	453,983	0.882	2.78%	0.33%
PEG Peer Average [2]	**1.83%**	**1,147,448**	**0.847**	**2.75%**	**0.38%**
Difference from Enbridge	**1.12%**	**(381,849)**	**0.075**	**-0.08%**	**-0.27%**
NE Peer Group					
Baltimore Gas and Electric	**1.95%**	624,862	0.894	1.51%	0.16%
Central Hudson Gas & Electric	**2.06%**	69,081	1.022	1.72%	-0.04%
Nstar Gas	**2.62%**	252,576	0.897	1.23%	0.13%
Connecticut Energy	**1.27%**	170,817	0.953	1.14%	0.05%
Connecticut Natural Gas	**0.18%**	151,127	0.892	-0.64%	-0.07%
Consolidated Edison	**0.86%**	1,041,458	0.796	0.18%	0.04%
Niagara Mohawk	**1.62%**	560,566	0.842	0.40%	0.06%
Orange and Rockland	**-0.93%**	123,577	0.940	1.18%	0.07%
PECO	**1.19%**	464,619	0.890	1.59%	0.17%
People's Natural Gas	**0.69%**	355,134	0.880	0.08%	0.01%
PG Energy	**1.15%**	159,242	0.942	1.00%	0.06%
Public Service Electric & Gas	**-0.51%**	1,693,048	0.776	0.65%	0.15%
Rochester Gas and Electric	**0.94%**	293,334	0.896	0.60%	0.06%
New Jersey Natural	**1.83%**	453,983	0.882	2.78%	0.33%
NE Peer Average [2]	**1.07%**	**458,102**	**0.893**	**0.96%**	**0.08%**
Difference from Enbridge	**0.36%**	**(1,071,195)**	**0.121**	**-1.87%**	**-0.57%**

[1] The average TFP trend will differ from that based on a size-weighted average of the company results.

[2] The expected scale economies of the peer group is an average of the scale economies for individual companies. The expected scale economies calculated using average values of [E] and [dYe] will not equal the average of the expected scale economies calculated independently by company.

IGUA #41

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 8 of 24
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

Dr. Carpenter alleges that based on data currently available, the companies that make up the peer groups that PEG has chosen for EGD do not have business characteristics that are similar to EGD's. Does PEG agree with this statement? If not, why not?

RESPONSE

Certainly not. These companies were chosen precisely for the similarity in the business conditions that are known to drive TFP growth. Please see our response to IGUA Exhibit R-PEG Tab 5 Schedule 12 for a full discussion of our objections to the Enbridge testimony.

Witness: Mark Lowry

IGUA #42

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 11 of 24
Issue No.: 3.1
Issue: How should the X factor be determined

Dr. Carpenter observes that in Dr. Lowry's April 2007 testimony in California, Dr. Lowry reported that the average annual growth in TFP during 1994 to 2004 was 0.63%. In Dr. Lowry's June 2007 Ontario report he reported an average annual growth rate in TFP for that same time period for the U.S. sample as 1.18%.

(a) Please explain the reasons for the different growth rates in the annual TFP between Dr. Lowry's April, 2007 testimony and the June, 2007 report.

RESPONSE

The results from our work for the OEB differ from those in our California (CA) testimony referenced above, due chiefly to changes in the research methodology intended to make our methods more rigorous and more germane in an application to Enbridge and Union.

1. In the CA work we used total throughput as a workload measure in the output index. In the OEB work, we split total throughput into residential / commercial deliveries and other deliveries so as to improve our ability to recognize the different cost challenges faced by Union (which has a large transmission volume) and Enbridge (which doesn't).

2. We excluded 3 companies from the CA sample that did not report the necessary split of deliveries.

3. We used weather normalized deliveries for residential / commercial deliveries in the OEB work and not in the CA work.

4. The econometric model changed because of the downsized sample and because we removed some interaction terms from the model so as to get more sensible company-specific cost elasticities.

Witness: Mark Lowry

5. We used (upgraded) company specific elasticities in the OEB work instead of the sample mean elasticities used in the CA work. This was done to improve recognition of the different cost challenges facing Enbridge and Union.

6. We reduced the rate of return used in the calculation of capital cost to bring it in line with Ontario gas utility norms. This reduced the weight on the capital quantity, which grows more rapidly than the quantity of O&M inputs.

7. Our OEB research featured a new COS approach to capital costing rather than the GD approach featured in the CA work. This was done chiefly to facilitate the calculation of the input price differential (IPD). The IPD was not an issue in the California proceeding.

Please see our response to IGUA Exhibit R-PEG Tab 5 Schedule 12 for a comprehensive discussion of our many objections to the Enbridge testimony.

Witness: Mark Lowry

IGUA #43

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 14 of 24
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

Dr. Carpenter states that PEG's Ontario model can only be considered robust and unbiased if it includes all of the variables that explain Gas Distribution Costs, and that one of those variables is Customer Density.

(a) Does PEG agree with this statement? If not, why not?

(b) Does PEG's Ontario model take into consideration Customer Density? If not, why not?

RESPONSE

a) We believe that this is one contention of Dr. Carpenter that may merit further investigation, as we discuss further in our response to IGUA Exhibit R-PEG Tab 5 Schedule 12.

b) No. We excluded a line miles variable from the model because its inclusion rendered the "other" delivery volume variable insignificant.

Witness: Mark Lowry

IGUA #45

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 18 of 24
Issue No.: 3.1
Issue: How should the X factor be determined?

Dr. Carpenter states that number of customers is by far the single most important determinate of costs in PEG's model, and that under PEG's reasoning the positive and significant quadratic number of customers variable should lead to an opposite conclusion regarding the ability of companies the size of EGD to realize future scale economies. Does PEG agree with this assertion? If not, why not?

RESPONSE

No. Our mention of the negative quadratic term for volume was only intended to explain why our econometric research finds that large companies can still earn incremental scale economies from output growth. Evidently, the positive sign on the customer quadratic term is not enough to offset this effect. Please see our response see Exhibit R-PEG Tab 5 Schedule 12 for a full discussion of our many objections to the Enbridge testimony.

Witness: Mark Lowry

IGUA #46

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 19 of 24
Issue No.: 3.1
Issue: How should the X factor be determined?

Dr. Carpenter states that PEG does not appear to have considered a Northeast Regional approach to its econometric model, even though that was the approach PEG took in the model's estimation for Boston gas in 2003.

(a) Did PEG consider a Northeast Regional approach to its econometric model? If not, why not?

(b) If PEG did consider this approach, did it apply any regional dummy variables to test for Northeast Regional effects? If not, why not?

(c) If the answer to (b) is no, please explain why PEG employed a dummy variable in the sample utilities located in the Northeast U.S. in its models estimation for Boston gas in 2003, but has not done so in Ontario in 2007.

RESPONSE

a) We briefly considered this option but quickly realized that northeast U.S. utilities, which unlike Union and Enbridge are generally small companies struggling with slow customer growth, comprise a remarkably bad peer group option.

b) Not applicable

c) Please see our response to IGUA Exhibit R-PEG Tab 5 Schedule 12 for a discussion of this issue.

Witness: Mark Lowry

IGUA #47

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 21 of 24
Issue No.: 3.1
Issue: How should the X factor be determined

In addressing EGD's cast iron replacement program, Dr. Carpenter alleges that it is "patently unreasonable" for PEG to reject any adjustment for a known and important cost driver over the plan for EGD on the basis of "a statistically unconfirmed null hypothesis" associated with sample data that may not even reflect such programs.

a) Is PEG aware of any U.S. utilities where an adjustment for a cast iron main replacement program has been incorporated into a PCI or RCI? If yes, please provide details.

b) Please provide PEG's response to the allegation that it is patently unreasonable to reject any adjustment for a known and important cost driver over the plan period for EGD.

RESPONSE

a) No.

b) We disagree with this contention, as we discuss further in our response to Exhibit R-PEG Tab 5 Schedule 20.

Witness: Mark Lowry

IGUA #48

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 5 of 64
Issue Nos.: 3.1 and 13.1
Issue: 3.1 How should the X factor be determined?
13.1 What information should the Board consider and stakeholders be provided with at the time of rebasing?

Dr. Bernstein states that since the IR Plan under the OEB involves price rebasing at the end of the IR plan, it is redundant to include a positive stretch factor. Does PEG agree with this statement? If not, why not?

RESPONSE

No. Please see our response to Exhibit R-PEG Tab 5 Schedule 12 for a full discussion of our objections to the Enbridge testimony.

Witness: Mark Lowry

IGUA #50

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 22 of 64
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

Dr. Bernstein states that PEG's AU effect does not in fact account for the prevailing and prospective declines in service usage, which differ from past trends. As a consequence, the PCI and RCI developed by PEG are deficient. Does PEG agree with this conclusion? If not, why not?

RESPONSE

No. Please see in our response to Exhibit R-PEG Tab 5 Schedule 12 a discussion of this issue.

Witness: Mark Lowry

IGUA #51

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 23 of 64
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

Dr. Bernstein states that since future prices will be rebased at the end of the forthcoming IR period, that rebasing procedure transfers productivity improvements to consumers and eviscerates the rationale for a stretch factor. Does PEG agree with this proposition? If not, why not?

RESPONSE

No. Please see in our response to Exhibit R-PEG Tab 5 Schedule 12 a discussion of this issue.

Witness: Mark Lowry

IGUA #52

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 27 of 64
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

Dr. Bernstein states that PEG's analysis and calculation of its specific X factors must be rejected on the basis of its arbitrary calculation and flawed analytical development. Does PEG agree that its calculation of the service specific X factors were arbitrary and were flawed? If not, why not?

RESPONSE

No. Please see our response to Exhibit R-PEG Tab 5 Schedule 12 for a full discussion of this issue.

Witness: Mark Lowry

IGUA #54

INTERROGATORY

Ref:
Issue No.:
Issue:
Does the evidence provided by EGD with respect to the X factor change PEG's opinion on the PCI or RCI set out in the PEG Report?

RESPONSE

PEG believes that Enbridge has taken a "blunderbuss" approach to the research set forth in the June report that is designed to discredit it, while providing very little substantiation for the Company's alternative proposal. Very few of the criticisms have merit and many concerns could have been resolved earlier had Enbridge asked us more substantive questions about the work at earlier stages of this regulatory initiative. However, a few of their ideas may merit further research. These are discussed further in our response to Exhibit R-PEG Tab 5 Schedule 12.

Witness: Mark Lowry