Comments by Francis J. Cronin

On

The IPI versus Macro Output Price Indexes; Calculating the IPD and PD in GDP Price Index RAMs; TFP Estimates with Volume-Based Output and Line Loss Inputs

In the matter
of the
Ontario Energy Board's

3rd Generation Incentive Regulation for Electricity Distributors

(EB-2007-0673)

On behalf
of
Power Workers' Union

May 20, 2008

1.0 Introduction and Summary of Issues

I comment on several recently arisen issues for 3rd Generation IR for Ontario electricity distributors.

Issues

First, I comment on Pacific Economics Group's (PEG) statement that the use of customer connections without kWh sales in 1st Generation biased the reported total factor productivity (TFP) of 0.86 downward. Second, I comment on Staff's May 6th, 2008 Proposal to use the GDP price index rather than the input price index (IPI) in 3rd Generation Incentive Regulation (IR). Third, I comment on PEG's input price differential analysis (IPD) and their recommended finding of zero for the IPD.

Conclusions

First, I find that leaving kWh sales out of the TFP analysis in 1st Generation IR for the Ontario electricity distributors did not bias downward the results; in fact, average TFP growth based on kWh are over 1.00 percent lower from 1988-1997 than those based on customer connections. What would have biased downward the reported TFP in 1st Generation IR would have been removing line losses from LDC inputs; TFP with line losses included had an average TFP 0.5 percent higher than without line losses. PEG's TFP estimate for 3rd Generation IR excludes line losses.

Second, I conclude that use of the GDP price index would necessitate IPD and productivity differential (PD) adjustments to align historical LDC input price trends with macroeconomic price trends. These adjustments have been recognized by regulators for over a decade. These necessary adjustments to bring the GDP price index into theoretical equivalence with the IPI means that complex and potentially volatile modifications must be made with the IPD, making the IPI a safer, simpler, and more transparent approach.

Reviewing the research in Ontario since 1986, I find that IPDs for distribution utilities have ranged from -1.1 to -2.3 for both gas and electricity LDCs, i.e., LDC input prices have consistently grown more slowly than macro input prices. These results span four, ten and nearly twenty-year periods. Therefore, based on an historical assessment of trend relationships, the X factor in a GDP price index formula should be adjusted upward to account for the consistently measured IPD findings that indicate that aggregate input prices are growing more quickly than are LDC input prices. This would produce the just and reasonable rates that a formula based on the industry IPI would have produced.

The findings are based on research undertaken by myself, Christensen Associates (CA) and PEG. While such adjustments are necessary to produce just and reasonable rates based on historical relationships, they may not reflect future relationships. We cannot know the future; what we can say with a high degree of certainty is that an unadjusted GDP price index will not reflect the trends in LDC input prices; either ratepayers or shareholders will benefit from unexpected/unknowable changes in input trend relationships.

PD has been both negative and positive. With respect to the negative findings, the PD has ranged from -1.00 over the 1988-1997 period to -0.24 over the 1988 to 2006 period. However, over the most recent 10-year period, the PD has been 0.42. Which period to select to include in the 3rd Generation Rate Adjustment Mechanism (RAM)? Should the adjustment be positive or negative?

While the February Staff paper discussed the IPI and derived its formulation from the IPI specified in 1st Generation, the current Board staff proposal appears to reject the IPI; and then what: decide what exactly the truth is based on empirically calculated historical IPD and PD adjustments. Board staff's consultant recommends that the IPD be set at zero. However, his empirical findings for Ontario as well as my research finds little, if any support based on Ontario data to set an IPD at zero as PEG recommends. The IPD historical adjustments range from about -1.1 to -2.3 with some of the values having been adopted by the Board in prior IR cases. While there is some variance within a range of -1.1 to -2.3, historical Ontario data is quite clear that the IPD has not been zero.

With Board staff's proposal for 3rd Generation IR, either ratepayers or shareholders will gain unfairly or lose over the term of the plan based on the decision to fix the IPD and PD for the proposed term of the plan (i.e. 5 years); it is just a question of how much either party will gain or lose. As there is no way of knowing what the future IPD and PD would have been, therefore the question of degree of gains/loses remains unknown. The alternative is to reject the GDP-IPI and its IPD and PD adjustments and implement a simpler, fairer, and higher incented IPI approach: reimburse LDCs for input price inflation; this eliminates the associated risk to both shareholders and ratepayers from the input price roulette game played with GDP price indexes and IPDs. A possible second best approach is to reset the IPD and PD annually to preclude the potential compounding of errors over the 3 to 4 remaining years of the plan with a fixed IPD and PD.

2.0 Examining Volume (kWh) Based Productivity and the Importance of Line Losses in 1st Generation IR TFP Estimates

PEG has relied upon 1st Generation IR results to support their analysis and findings; I support their use of that research and results. On the whole, PEG's interpretations and comments have been accurate and fair. On one point, however, the lack of volume (kWh) based TFP in 1st Generation IR, PEG's comments are not quite accurate.

Intent and Circumstances of 1st Generation IR

Recall, 1st Generation IR was implemented as a framework to cover the nearly 300 distributors that operated in 2000. The 1999 Staff Report[1] that provided the basis for 1st Generation IR was structured to be readily understood for ease of implementation by the distributors. Therefore, much of the research that was undertaken for 1st Generation IR was not included in that document, including details on the complete set of TFP research conducted.

For example, alternative specifications of distribution output were examined, including the inclusion of distribution volumes (kWh). However, there was nearly universal support among the distributors and other stakeholders to not include kWh in the TFP output. Due to this consensus and the need to keep the Staff report as manageable as possible, research on these findings were shared with stakeholders but not included in the final Staff report.

Alternative TFP Specifications in 1st Generation

PEG has noted in their 3rd Generation report and at the May 6, 2008 Stakeholder Conference that the lack of kWh as an output measure in 1st Generation IR biased results downward.[2] In fact, the examination of kWh based output found that its use lowered the TFP results. In Exhibit 2.1, I present TFP results for both customer connections and kWh as the measure of output for both the initial sample of 40 distributors and the final sample of 48 distributors analysed for the 1988 – 1997 period. Note that in both samples, using the kWh output measure substantially lowers the estimated TFP. In the case of the initial sample of 40 distributors, estimated TFP is lowered

[1] Cronin, F., et al, 1999, *Productivity and Price Performance for Electric Distributors in Ontario,* Ontario Energy Board Staff Report.
[2] PEG Presentation, May 6, 2008, p.34.

from 0.77 using customer connections to -0.41 using kWh, a decrease of 1.18 percent. In the case of the final sample of 48 distributors, the estimated TFP is lowered from 0.86 to -0.18 a decrease of 1.04 percent.

Exhibit 2.1: 1st Generation TFP Results, Alternative Specifications: 1988 - 1997

(average percent per year)

	Customer Connections	**kWh Sales**	**No Line Losses In Inputs**
Initial Sample of 40 MEUs	0.77	-0.41	0.30
Final Sample of 48 MEUs	0.86	-0.18	0.35

Source: 1st Generation IR Analysis

I have included in the results above the findings of a second alternative specification, estimated TFP which does not include line losses as an input. Recall that the 1st Generation IR reported results of an 0.86 percent per year increase in TFP were based on customer connections as the output and a comprehensive specification of inputs including labour and materials (O&M), properly measured capital stock, and line losses. I found that the failure to include line losses biased the TFP results by about 0.50 percent a year.

Why would that be so? From 1988 to 1993, the wholesale price of power rose 45 percent for distributors. I found that many of these distributors had reacted to these large price increases by increasing O&M or capital projects to reduce their line losses and thus the overall cost of distribution. Had losses not been included in the 1st Generation IR analysis, actual TFP growth would have been underestimated by more than 100 percent.

Today, we are in a similar situation to 1988 – 1993: power costs have escalated dramatically. Hopefully LDCs are increasing O&M and capital projects to reduce their losses and overall costs. The failure to include line losses therefore could be biasing PEG's reported TFP results downward. The failure to make line losses a clear responsibility of the LDCs would send the wrong incentive signal at a time when each and every LDC should be aggressively examining all its options for reducing power losses.

The Importance of System Losses

The April, 2007 PEG report on distributor cost comparisons describes the distribution business and related inputs as follows:

> Power flows to the customer through wire conductors. Other capital inputs used in local delivery include poles, conduits, station equipment, meters, vehicles, storage yards, office buildings, and information technology ("IT") inputs such as computer hardware and software. Distributors commonly operate and maintain such facilities and are also frequently involved in the construction of distribution plant. These activities require labour, materials, and services. Local delivery also typically requires a certain amount of power in the form of line losses. Opportunities are available to outsource many OM&A and construction activities. Distributors vary greatly in the extent of their outsourcing. (p 28)

Despite this description of the importance of power losses, PEG does not use this measure in its proposed cost benchmarking or 3rd generation framework. Just how are line losses integrated by each utility in the distribution of power?

Distribution utilities act as the middleman transporting electricity from wholesale to retail markets. Resistance to the flow of electric current throughout the distribution network causes a portion of the electricity entering the network to be lost in the form of heat. Network characteristics such as conductor size, type of transformers, end-user power factors, and non-optimal loads and voltage can affect system losses which range from 6 to over 20 percent as a share of total distribution costs. During energy price spikes, the cost associated with line losses of electricity can increase dramatically. Between 1988 and 1993, the wholesale price of power increased 45 percent in Ontario. Indeed, the price of power rose faster than other inputs between 1988 and 1993 and between 1988 and 1997. Energy "crises" have sparked intense system audits by some utilities to identify the sources of losses and potential network remedies, including:

1. system automation equipment to optimise load;
2. capacitors to compensate for low power factors among some end users;
3. reconductoring to increase conductor size and reduce resistance;
4. higher cost, high-efficiency transformers which reduce losses associated with transformer activation (core) and/or load (winding); and
5. system regulators to optimise voltage.

Clearly, the use of such remedies to reduce system losses means that greater amounts of capital are being employed. Some of these remedies also require higher levels of OM&A. For example, the use of capacitors to correct the effect of reactive power from certain end-users' applications means that equipment is being more widely dispersed and that equipment failures increase as more fuses, switches and controls are deployed closer to the customer. Installation of system voltage optimisation and phase current balancing equipment increases the OM&A associated with such regulating equipment.

Numerous Ontario utilities relying on the substitution possibilities among their inputs attempt to optimize their production with different input mixes based on substitution possibilities, circumstances and prices. So, two LDCs might produce the same output but one uses more capital and less labour while the second uses less capital and more labour. Comparisons of O&M without the proper control for differences in capitalized labour and/or capital will lead to biased results which do not have the credibility for rate making purposes.

3.0 The Industry Input Price Index versus Macro Output Price Indexes

Board staff have proposed the use of the GDP price index in 3rd generation rather than the IPI. The IPI has numerous favorable factors in its consideration.

Conceptual Considerations

The IPI plays a critical, multi-dimensional role in an IR. The IPI sets an automatic adjustment for LDC cost changes. It obviates the need to hold frequent cost of service (COS) proceedings. The IPI mirrors the COS process by adjusting rates on prudency basis, but uses experience of sector average as the prudency test. It mitigates the likelihood that mistakes in RAM associated with a macroeconomic price index (e.g. GDP-IPI) will over/under compensate LDCs. Finally, it establishes yardstick (e.g. benchmark) competition among Ontario LDCs, with better performers holding down costs. These better performers than stand to gain as their profits reflect the cost savings achieved; customers gain as the lower price benchmarks are reflected in lower distribution costs for all customers, not just those of the better IPI performers. And finally, the IPI provides proper incentive signals to LDCs and customers.

The February Staff paper discussed the basis, rationale and formulation of the IPI. This formulation was based on the IPI implemented by the Board in 1st Generation. The 1st Generation review vetted this approach and was widely accepted by stakeholders. During the 3rd Generation process there appeared to be wide acceptance of the appropriateness of the IPI although some commentators had what I would call 2nd or 3rd order issues for consideration. I believe that these issues could be expeditiously dealt with in a very short period of time, i.e., a day or two of consultation.

Implementation Considerations

Use of a macro output index like the GDP price index means that adjustments must be made to the index to correct for known and significant distortions between the trend in industry input prices and the GDP price index. Regulators around the world have recognized the need to make these adjustments for over a decade and they are standard practice in IR frameworks. To ignore documented differences in price trends between LDC input prices and price indexes like the GDP means that based on historical relationships, customers would be charged rates that by and large generally rose too quickly. Such rates could not be just and reasonable. Going forward, trend relationship might change; if LDC input prices rose less rapidly than the GDP price index, an unadjusted macro price index would under recover revenue from customers; such rates could not be just and reasonable.

Issues not Vetted in 3rd Generation

We know that an index like the GDP must be adjusted by both an IPD and a PD. But these issues have not been vetted in any consultation process on 3rd Generation. Only in PEG's May 6th presentation has any information been put forth on the values of the IPD and nowhere for the PD. Exhibit 3.1 presents IPD estimates for Ontario distributors covering the twenty year period 1986-2006.

Exhibit 3.1: IPDs for Ontario Gas and Electric Distributors: 1986 to 2006 with Sub Intervals

(Percent Adjustments per Year to the RAM)

	IPD	Comments
OEB Union Decision[3]	-1.1	1986-1996. Volatile.
1st Generation IR for Electric Distributors	-1.2	1988-1997. Calculated later.
PWU Gas IR Filing[4]	-1.3 -1.6 -2.0	1989 -1997 Volatile in some 1996-2006 shorter periods 1990-2006 closer to end.
PEG 3rd Generation IR for Electric Distributors	-1.4 -2.3	1991-2006 Relatively 2002-2006 stable.
PWU 3rd Generation IR for Electric Distributors	-1.8 -2.3	1991-2006 Relatively 2002-2006 stable.

Note: negative number indicates that LDC input prices grew more slowly than macro input prices.

Reviewing the research in Ontario since 1986, I find that IPDs for distribution utilities have ranged from -1.1 to -2.3 covering both gas and electric LDCs over four, ten and nearly twenty-

[3] Decision with Reason, RP-1999-0017, 2.247.
[4] Cronin, F. PWU Gas IR Undertakings, No.17 and No. 23.

year periods, i.e., LDC input prices have consistently grown more slowly than macro prices.[5] Therefore, based on an historical assessment of trend relationships, the X factor in a GDP price index formula should be adjusted upward to produce the just and reasonable rates that a formula based on the industry IPI would have produced.

The findings are based on research undertaken by myself, CA and PEG. While such adjustments are necessary to produce just and reasonable rates based on historical relationships, they may not reflect future relationships. We cannot know the future; what we can say with a high degree of certainty is that an unadjusted GDP price index will not reflect the trends in LDC input prices; either ratepayers or shareholders will benefit from unexpected/unknowable changes in input trend relationships.

The Fundamental Advantage of the Industry IPI Approach over the GDP-IPI and IPD

First, let me reiterate that I am recommending that the Board adopt a RAM based on an industry IPI. This approach eliminates the need to calculate both the IPD and the PD with all the associated errors involved with those calculations. But, even more fundamental to the argument supporting the IPI approach over the GDP-IPI approach: *the latter approach requires that the regulator determine an IPD value which is fixed for the term of the plan*. In the macro approach, only the GDP-IPI varies during the term; *it is assumed that the relationship that existed between the industry IPI and the macro (i.e., Canadian IPI) IPI will remain the same over the 3, 4, or 5 years of the plan.* But, the fact is that the IPD can, over short periods of time, deviate from long term trends that have been in place for many years if not decades.

Inherent Stakeholder Risk with an IPD Approach

If the IPD changes during the IR, either the shareholders or ratepayers will experience a windfall; conversely the other party will suffer a loss. This is not necessary and quite easily prevented by adopting an industry IPI approach in which the target TFP is fixed for the term but the IPI varies each period based on the actual change in input prices. The utility is compensated for increases in input prices; if it were to do better than these market prices it would be rewarded. The IPD plays no role in an industry IPI approach and is extraneous.

[5] This research is discussed below.

Note that in order to calculate the IPD, we must derive the Canadian IPI; this variable is not reported by Statistics Canada. In order to estimate a proxy for this variable we use the sum of GDP-IPI and reported Canadian productivity.[6] Using such a construct, my submission and undertakings in the OEB's gas IR proceeding (EB-2007-0606 and EB-2007-0615) documented IPDs in the 1.0 to 2.0 range.

The Conundrum: Long-Term Consistency, Recent Upwards Deviations, or Outliers

Recall then that an IR structured on an industry IPI/TFP approach does not need to determine an IPD: it is not part of the RAM. *However, if we use Staff/PEG's macroeconomic approach, we must select an IPD which will be fixed for the term of the plan.* What a dilemma: reject the IPD and then decide what the truth is for the IPD/PD. And all the while, either ratepayers or shareholders will gain or lose based on the decision to fix the IPD for 3 to 5 years; it's just a question of how much either party will gain or lose with no way of knowing the future 5 years of the IPD. Or, reject the GDP-IPI and IPD approach and implement a simpler, fairer, and higher incented IPI/TFP approach: reimburse gas LDCs for input price inflation beyond their control; this eliminates the associated risk to both shareholders and ratepayers from the input price roulette game played with IPDs.

[6] My submission/undertakings in the recent natural gas distribution IR discusses the problems associated with using the sum of GDP-IPI and Canadian productivity to estimate the unknown Canadian aggregate IPI. In order to estimate an IPD, however, we are forced to employ this estimated construct.

4.0 Developing an IPD and PD

In this section we review estimated IPD and PDs for Ontario distributors. A review of the theory and evolution of IR and the role of IPDs and PDs is provided in Appendix A.

Input Price Differentials

Christensen Associates Estimated Union Gas IPD

The CA study calculated an IPD of -1.1 for Union Gas (i.e., Union's IPI grew 1.1 percent more slowly than did input prices in the overall economy).[7]

Intervenor cross by Brett of CA:

Mr. Brett: "What you do know for a fact is that over this last ten years you have had a lower rate of input inflation in Union than you had in the Canadian economy as a whole."

Dr. Schoech: "Yes. There was a difference of 1.1 percent."

But as noted in the Board's Decision with Reason, "Union's position was that an input differential of zero would be appropriate."[8] "Union argued that the volatility of the input price data that yielded a calculated input price differential of -1.1 percent was so high that the result was 'not statistically valid."[9] Union further argued that the IPD is not statistically different from zero due to the high volatility of the historical data….[10]

Dr. Hemphill: "..but it is also stated on p. 30…that those input prices show a great deal of volatility. There are 2 years where it increases more than 20 percent. There is a year where it decreases by 33 percent. So we felt comfortable in this study to consider—to go ahead and make the assumption that the input price differential is zero."[11]

[7] Decision with Reason, RP-1999-0017, Transcript Vol. 6, 885.
[8] Decision with Reason, RP-1999-0017, 2.273.
[9] Decision with Reason, RP-1999-0017, 2.252.
[10] Decision with Reason, RP-1999-0017, 2.280.
[11] Decision with Reason, RP-1999-0017, Transcript Vol. 6, 863.

As the Board Decision stated, Schools noted the actual findings from the Union study of an IPD of -1.1. Schools further stated that Union's position was "arbitrary." [12] The Board rejected Union's position and noted the company's assertion that its "input usage is significantly different from input usage in the Canadian economy overall.[13]"

1st Generation IR for Electric Distributors

The IPI developed in the 1st Generation IR for electric distributors did not explicitly examine an IPD since the consensus was to implement an industry IPI. However, subsequently I did calculate what the IPD would be for the period used in 1st Generation. Over the 1988-1997 period, the IPD is -1.2 percent, coincidently quite similar to the CA IPI estimated for the 1986-1996 period.

Cronin Estimated IPD for the Gas IR

Over the longest period covered by the data (i.e., 1990 to 2006) I calculated the IPD is -0.9 percent; that is the growth in the Canadian IPI (2.1 percent) exceeded the growth in the gas IPI (1.2) by 0.9. For some shorter periods the IPD is larger (in absolute value): for 1999-2005 it is -1.3; for 2001-2005 it is -2.7 Only for some periods beginning in 1998 do we find aberrations of positive but small estimates.

PEG Estimated IPD for 3rd Generation

IPD estimates were presented in PEG's May 6th, 2008 presentation. For the longest period covered, 1991-2006, the IPD is estimated at -1.4. Looking only at the last four years, i.e., 2002-2006, PEG's estimate is -2.3.

Cronin Estimated IPD for the 3rd Generation IR

I have examined the data underlying the IPD. My estimates are generally consistent with PEG's in terms of the scale and direction. For the longest period covered, 1991-2006, I estimate that the IPD for electric distributors is -1.8, slightly higher (in absolute value) than the -1.4 estimate from

[12] Decision with Reason, RP-1999-0017, 2.254-55.
[13] Decision with Reason, RP-1999-0017, 2.281.

PEG. Looking only at the last four years, i.e., 2002-2006, I estimate the IPD is -2.3, the same as PEG's estimate.

Three sets of IPD results present themselves:

1. From the mid-late 1980s to the late 1990s, the IPD for electric and gas LDCs estimated by CA and myself ranges from -1.1 to -1.3.

2. From the early-mid 1990s to 2006, the IPD for electric and gas LDCs estimated by PEG and myself ranges from -1.4 to -2.0.

3. From 2002 to 2006, the IPD for electric LDCs estimated by PEG and myself equals -2.3.

The research on Ontario LDC IPDs is clear: CA, PEG and I all find consistent IPDs for various time periods spanning the last 4 years to the last 20 years. What the Board must do is decide which historical period best describes the next 4 to 5 years for 3rd Generation.

Clearly, the evidence based on Ontario historical data is that the IPD has ranged from -1.1 to -2.3 over the last twenty years. There is no Ontario evidence to support PEG's recommended IPD of zero for 3rd Generation.

Productivity Differentials

As far as I can tell, no information has been presented on the size and sign of the productivity differential, $dTFP^A - dTFP^u$, despite the fact that this adjustment must be made to make the GDP price index theoretically conform with the IPI. However, our efforts to calculate this required adjustment are hampered by the fact that we only have good data on Ontario LDCs' TFP for the 1988-1997 period. No estimates exist for 1998-2001 and PEG has heavily qualified its estimate of TFP from 2002-2006 due to lack of capital data. We do however have the data to estimate the PD from 1988-1997; in order to estimate the PD from 1988-2006 and from 1998-2006, I assume the LDC TFP is zero between 1998 and 2006.

Looking at the PD in Exhibit 4.1 we see that it has been both negative and positive. With respect to the negative findings the PD has ranged from -1.00 over the 1988-1997 period to -0.24 over the 1988 to 2006 period. However, over the most recent 10-year period, the PD has been 0.42. Which period to select to include in the 3rd Generation RAM? Should the adjustment be positive or negative?

Exhibit 4.1: Estimated Productivity Differentials: 1988-2006

	Aggregate TFP	LDC TFP	Differential (PD)
1988-2006	0.16	about 0.40	-0.24
1988-1997	-0.14	0.86	-1.00
1997-2006	0.42	about 0.00	0.42

Note: I assume that the Ontario TFP for electricity LDCs is zero over the 1998-2006 period.

Recommendation: The 3rd Generation RAM should be based on industry IPIs and not the GDP price index. Use of the IPI eliminates numerous estimated factors such as the IPD and PD from the price cap formula and the inherent errors associated with such statistical calculations. Potential inherent errors are accentuated by the need in the GDP approach to have price data which does not exist (e.g., economy wide IPI) and which is created based on untested and potentially implausible assumptions. However, if the Board opts for the GDP price index in 3rd Generation IR, then it is incumbent that an IPD estimated on Ontario historical data be included in the RAM. However, while such adjustments are necessary to produce just and reasonable rates based on historical relationships, they may not reflect future relationships. We cannot know the future; what we can say with a high degree of certainty is that an unadjusted GDP price index will not reflect the trends in LDC input prices; either ratepayers or shareholders will benefit from unexpected/unknowable changes in input trend relationships.

Appendix A: IPD & PD Required for Rate Adjustments in Proposed 3rd Generation IR

Since the Staff proposal recommends the GDP price index, economic theory, regulatory precedent, including the OEB, and the requirement for just and reasonable rates necessitate that an IPD and PD adjustment be included in the RAM. This appendix reviews the theory and evolution of IR regulation and the role played by IPDs and PDs.

THE THEORY AND EVOLUTION OF PRICE CAP REGULATION

The economic theory underpinning price caps relates the change in a firm's output price to the change in unit costs – i.e., the change in *output* price for a regulated utility equals the change in the utility's *input* prices minus the change in its *productivity*. Assuming no change in profit, this can be written as:

$$(1) \qquad dp^u = dw^u - dTFP^u$$

Where the d operator indicates annual percentage change, the superscript denotes the regulated utility, p is the relevant output price, w is the relevant input price, and TFP is the firm's total factor productivity.

Early Applications of IR

In fact, the earliest major application of IR employed the straightforward direct approach based on equation (1). In the decade of the 1980's, the U.S. Interstate Commerce Commission (ICC) successfully implemented price caps as a form of alternative regulation for major rail carriers in the U.S. The general price cap framework adopted and refined by the ICC between 1980 and 1989, *directly* measures changes in railroad unit costs in order to develop a maximum cap for regulated rail prices. Specifically, the calculation includes two components: the change in the railroad input price index (i.e., the "rail cost recovery index") minus the change in the railroad productivity index.

With respect to the cost recovery index, the ICC explicitly ruled out the use of readily available, aggregate measures of price escalation for the reason that such measures are too broad and "include many elements unrelated to rail costs."[1] Rather, an "all inclusive" index created by the American Association of Railroads, and modified by stakeholder inputs including federal and state governments, individual shippers and their associations, trade associations, and the ICC, was implemented in January 1985.[2] The index is a fixed-weight, input price index consisting of seven components. For example, the ICC specified depreciation as the measure of capital usage and indexed it to the Bureau of Labor Statistics producer price index for capital.

Macro Price Indexes, the Differential Approach, and Errors

Some of the price cap plans put into effect since the ICC's IR have relied on a variant of the equilibrium condition depicted in equation (1) that we might label the differential approach. Such an approach seeks to simplify the ongoing annual calculations for adjusting the cap by measuring industry performance relative to that of the aggregate economy as a whole over some historical period[3]. Once certain relationships among prices and productivity at the aggregate economic level and the industry are estimated, the developers of the differential approach contend that the cap index can be updated by simply incorporating the most recent aggregate measure of price change.

In point of fact, many of the IR applications based on a differential approach implemented before 1997 (e.g., the Federal Communications Commission in the U.S. for access charges, Oftel's in the U.K. for British Telecom,) resulted in rapid, pervasive and large increases in earnings for the incumbent firms due to mistakes in the IR adjustment formula. Efforts to retain the differential approach by making it *theoretically* unbiased like the direct approach have now resulted in the need to include five adjustment parameters rather than the two in the direct approach. Since

[1] Interstate Commerce Commission, ExParte No. 290 (November, 1980), p.3.
[2] Ex Parte No. 290 (January, 1985), p.7.
[3] Early discussions of PBR in the 1980s and early 1990s sometimes considered employing an aggregate price index like the CPI as a substitute for the industry input price. However, the former is an output price representing consumers' purchases while the latter is an input price reflecting a specific industry's purchases. The composition of the two are markedly different. Even if one adjusts the CPI to track the input price index on average over some historical comparison period, that does not guarantee that the input price and adjusted CPI would track over subintervals. Nor does an average adjustment equating the two prices over the historical period mean that over the future course of the PBR and the relationships underlying the adjustment would remain constant – particularly when the input price index would have a weight of 40 to 50 percent on capital.

some of these adjustment parameters (e.g., aggregate TFP) may not be available for the past several years, the differential approach is forced to employ older data upon which to estimate its multiple differential relationships.

To see these relationships, recall equation (1) for an individual utility:

(1) $dp^u = dw^u - dTFP^u$

To derive the differential PBR formula, specify an aggregate version (A) of the equilibrium conditions as:

(2) $dp^A = dw^A - dTFP^A$

If we deduct equation (2) from equation (1)

We obtain:

(3a) $dp^u - dp^A = (dw^u - dw^A) - (dTFP^u - dTFP^A)$

or

(3b) $dp^u = dp^A + (dw^u - dw^A) - \mathit{(dTFP^u - dTFP^A)}$

The term on the left-hand side of (3a) is the difference in output price changes between the utility and the aggregate economy. (p^A could be represented by a relevant output price index issued by the government, such as the GDP price index.) Equation (3a) thus states that the difference in output price changes is a function of two terms: the first representing the difference between input price changes between the utility and the aggregate economy; the second representing the difference between productivity changes between the utility and the aggregate economy.

In their IR applications British regulators and by the FCC for the first ten years of alternative regulation, the first term on the right hand side of equation (7a) was not understood and not included. Utility input prices were growing more slowly than aggregate input prices, thus earnings tended to increase substantially for all utilities – not just those beating the productivity benchmark, i.e., $dTFP^u$.[4] As a result of these factors, regulators in the U.K. and the U.S. have responded to the unexpectedly sharp increase in earnings by instituting more frequent, detailed reviews than had been expected.[5] These reviews have usually resulted in regulators attempting to curtail the increase in earnings by raising the X factor more than 100 to 150 percent.

Thus, prior IR experiences with varying approaches to incorporating price and productivity in the price cap formula as well as theoretical considerations would seem to suggest that a direct approach would provide less risk (to both ratepayers and shareholders), more focused incentives, and the potential for a more effective PBR scheme. The direct approach, however, probably involves slightly more complicated update requirements. After considering these issues and the results discussed in Section 4, we recommend using a direct approach with a specific price index.

The Input Price Differential

In the case of the IPD, PEG has calculated an estimate based not on the difference between LDC input prices and the aggregate input prices, IPI^u and IPI^A or $IPD = (\Delta IPI^u - \Delta IPI^A)$, but rather between LDC input prices and a macro output price index, the GDP. Only if LDC growth in TFP equals aggregate growth in TFP, i.e, $dTFP^u = dTFP^A$
and both are zero, could PEG's calculations be correct.

Unfortunately, the second term in the IPD, the aggregate input price index IPI^A does not exist. Statistics Canada does not publish such a measure. Instead, in their Gas IR report, PEG proposed to use, an index based not on actual data, but on "index logic." "To the extent that the economy earns a competitive return in the longer run, the trend in its *input* prices is the sum of the trends in its *output* prices and its TFP (PEG IR Report, p. 53)."

(4) $\Delta P^A = \Delta IPI^A - \Delta TFP^A$

[4] In fact, $dTFP^u$ was also understated in many of these applications, in some cases being set below what turned out to be the historical average. Establishing the productivity factor so low reinforced the tendency for earnings to increase.

[5] This is not meant to imply that the observed increase in earnings was not based also on improvements in business operations undertaken by management in response to the incentives.

PEG provides no data or research to substantiate the appropriateness of this key assumption to derive such a critical parameter in the IPD. Recall, with an IPI framework, we have no need for and IPD or PD.

The Nature of a Competitive Economy

Let's look at the conceptual appropriateness of this "logic." Then we will examine the return data employed by PEG in their analysis.

To what extent can we assume that the economy earns a competitive return in the longer run and that assumption is applicable to the specific period chosen by PEG. According to the *Economist.com* magazine, "Perfect competition**"** is:

> *The most competitive market imaginable. Perfect COMPETITION is rare and may not even exist. It is so competitive that any individual buyer or seller has a negligible impact on the market PRICE. Products are homogeneous. INFORMATION is perfect. Everybody is a price taker. FIRMS earn only normal PROFIT, the bare minimum profit necessary to keep them in business. If firms earn more than that (excess profits) the absence of barriers to entry means that other firms will enter the market and drive the price level down until there are only normal profits to be made. OUTPUT will be maximised and price minimised. Contrast with MONOPOLISTIC COMPETITION, OLIGOPOLY and, above all, MONOPOLY.*

And, again according to the *Economist.com* magazine, the "Long run" is:

> *When we are all dead, according to KEYNES. Unimpressed by the thrust of CLASSICAL ECONOMICS, which said that economies have a long-run tendency to settle in EQUILIBRIUM at FULL EMPLOYMENT, he wanted economists to try to explain why in the short run economies are so often in DISEQUILIBRIUM, or in equilibrium at high levels of UNEMPLOYMENT.*

Economists generally consider the long run to be the period required for *all* inputs to be variable. For some technological changes, researches concluded that it took decades for firms and industries to adjust fully (e.g., the introduction of electricity). Perfect competition as defined and used by economists is a hypothetical construct; as stated in the Economist, "may not even exist."

In addition, it is probably the case that major sectors in the Canadian economy (and US economy) are more correctly identified as being closer to monopoly, oligopoly, or other non competitive market structures, especially if we are looking at periods encompassing the 1990s. These might include lumber; mining and some metals; gas and oil extraction; gas and oil processing; gas and oil transportation; automobile production; steel; operating software; utilities; rail; broadcasting; banking; health care; and, others. For the 1990s, telecommunications and cable would probably be added.

Indeed, Meagan Fitzpatrick, CanWest News Service January 17, 2007 reports that the Conference Board of Canada in its report "Mission Possible: Stellar Canadian Performance in the Global Economy" examines the regulatory burden, structural impediments and barriers to entry inhibiting industry competitiveness. Fitzpatrick reports the "study says that Canada's cumbersome system of regulations and barriers to competition interferes with the movement of goods and services, makes it harder for people to re-locate to obtain work and reduces the flow of investment within the country. The Conference Board wants the government to do something about the 'vast web of regulatory and other non-tariff barriers,' reform the tax system and open up more industries to competition…"

It appears that from the perspective of an economic paradigm, large, important sectors of the economy are not perfectively competitive. Further, key factor inputs (e.g., land, labor, location and infrastructure) may take more than 5 to 10 years to adjust to change. Conceptually, it appears that there is much doubt about the appropriateness of PEG's logic.

Equation (4), on which we calculate the aggregate IPI to compare to the LDC IPI, holds so long as there are no deviations in the underlying rates of return from competitive returns. PEG gas IR report presents ROE data on Canadian companies from 1988 to 2005 (see Gas IR report, Table 5-1). These returns range from a high of 12.7 percent (1988) to a low of 1.7 percent (1992). The last three years, i.e., 2003, 2004, and 2005, are the most similar to the first two years of the period. Research at the individual sectoral level (e.g. gas distribution in Ontario) has shown that the use of such distorted ROE results can lead to substantial errors in the calculations of implied annual changes in implied input prices.

Table ROE All Canadian Companies: 1988 to 2005

Year	ROE All Companies	Change	Percentage Change (%)
1988	12.7	NA	NA
1989	11.5	-1.2	-9.4
1990	7.6	-3.9	-33.9
1991	3.9	-3.7	-48.7
1992	1.7	-2.2	-56.4
1993	3.8	2.1	123.5
1994	6.7	2.9	76.3
1995	9.8	3.1	46.3
1996	10.3	0.5	5.1
1997	10.9	0.6	5.8
1998	8.8	-2.1	-19.3
1999	9.9	1.1	12.5
2000	10.9	1	10.1