Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario: Update

Presentation to IRM3 Stakeholders

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Introduction

PEG has

- Made preliminary recommendations for X factors for the third generation incentive regulation mechanism (IRM3) in Ontario

- Summarized our recommendations in a Draft Report for OEB Staff

Today's presentation will update those recommendations in light of the updated Staff proposal and stakeholder comments

Organization

1. X Factor Overview
2. Productivity Factor
3. Inflation Factor and Inflation Differential
4. Consumer Dividend
5. K Factor

X Factor Overview

Main objectives for regulatory framework to be established in IRM 3:

- Sustainable
- Predictable
- Effective
- Practical

X Factor Overview (Con't)

PEG has been guided by these objectives in developing its X factor recommendations

Intention has been to put in place

- Data Sources
- Empirical Tools

That

- Lead to reasonable X factors in IRM3
- Can be easily expanded and revised in future IR applications

>> current approach not set in stone for all future IR- it *should* evolve over time

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X Factor Overview (Con't)

With an Industry Price Index, the X factor is the sum of two components

1. The industry trend in total factor productivity (TFP)
2. A consumer dividend

When an economy-wide inflation measure is used as the inflation factor, it may also be appropriate for the X factor to include an inflation differential

>> depends on the relationship between industry input price trends and trends in the selected inflation measure

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X Factor Overview (Con't)

PEG originally developed recommendations for the productivity factor and a recommended approach for consumer dividends

In each case, we tried to use data and empirical techniques that

- Lead to reasonable current values
- Provide a sustainable – but flexible – basis for setting future X factors

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X Factor Overview (Con't)

The current presentation will:

- Examine our original productivity factor recommendation
- Consider the need – and magnitude – of an inflation differential
- Update our consumer dividend recommendations
- Evaluate the rationale for a proposed "K factor"

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Productivity Factor

Most X-factors in approved *North American* price cap plans are *calibrated* to track industry total factor productivity (TFP) trend

<u>Total Factor Productivity</u>

TFP = Output/Input

TFP Growth = Changes in Output Quantity minus Changes in Input Quantity

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Productivity Factor (Con't)

Indexing methods can compute measures of comprehensive output quantities (Y) and input quantities (X)

Change in TFP (ΔTFP) is then computed as

$$\Delta TFP = \Delta Y - \Delta X$$

PEG used indexing methods to calibrate a productivity factor for IRM3 <u>but</u> analysis was limited by available Ontario data

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Productivity Factor (Con't)

Output quantity a weighted average of:

- Customer Numbers
- kWh deliveries

Cost elasticity shares used as output weights

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Productivity Factor (Con't)

Input quantity a weighted average of:

- Labor inputs (if available)
- Other OM&A inputs
- Capital inputs

Changes in input quantity measured as changes in expenditure on the input minus the change in the associated input price subindex

>> input price indices constructed at same time as TFP indexes

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Productivity Factor (Con't)

Estimation of Industry TFP Trends

PEG considered three sources of information for setting industry TFP trends

1. TFP Estimation from previous IR applications in Ontario
2. Recent index-based TFP measures for Ontario industry
3. Recent index-based TFP measures for US industry

Productivity Factor (Con't)

Previous TFP Estimation from Ontario

In IRM1, Cronin and King estimated TFP trends for 48 Ontario electricity distributors for the 1988-97 period

Average TFP growth over period = 0.86%

Average TFP growth over second half of period = 2.05%

Board put more weight on second half TFP growth and approved a TFP trend of 1.25% (=2/3*0.86% + 1/3*2.05%)

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Table 1

Estimated TFP Growth in First Generation IRM

Entire Sample: 1988-97

Size Class	Output Quantity Growth	Input Quantity Growth	TFP Growth
Small	0.84%	0.27%	0.57%
Medium	2.05%	1.04%	1.01%
Large	1.08%	0.16%	0.92%
All Utilities	1.40%	0.54%	**0.86%**

"First Half" of Sample Period: 1988-93

Size Class	Output Quantity Growth	Input Quantity Growth	TFP Growth
Small	1.30%	1.77%	-0.45%
Medium	2.91%	2.59%	0.31%
Large	1.38%	1.66%	-0.28%
All Utilities	1.97%	2.06%	**-0.09%**

"Second Half" of Sample Period: 1993-97

Size Class	Output Quantity Growth	Input Quantity Growth	TFP Growth
Small	0.26%	-1.60%	1.85%
Medium	0.98%	-0.90%	1.89%
Large	0.71%	-1.71%	2.42%
All Utilities	0.69%	-1.36%	**2.05%**

Productivity Factor (Con't)

Previous TFP Estimation from Ontario

In IRM 2, the X factor was set equal to 1%

Determined through judgment and overall view of evidence and precedents from other proceedings

Productivity Factor (Con't)

<u>Current TFP Measures in Ontario</u>

PEG also estimated recent TFP trends for Ontario industry

High quality data available only since 2002

Data sources are RRR filings

Estimated capital stock for 2002 using reported book data and imputations on previous capital additions 1992-2002

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Table 3

OUTPUT QUANTITY GROWTH: ONTARIO POWER DISTRIBUTORS

Year	Output Quantity		Customers		Volume	
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
2002	1.00000		1.00000		1.00000	
2003	1.03055	3.01%	1.01996	1.98%	1.04883	4.77%
2004	1.04165	1.07%	1.03657	1.62%	1.05035	0.14%
2005	1.06892	2.58%	1.05081	1.36%	1.10048	4.66%
2006	1.06545	-0.33%	1.06398	1.25%	1.06795	-3.00%
Average Annual Growth Rate **2002-2006**		**1.58%**		**1.55%**		**1.64%**

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Table 4

INPUT QUANTITY GROWTH: ONTARIO POWER DISTRIBUTORS

Year	Input Quantity		OM&A		Capital	
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
2002	1.00000		1.00000		1.00000	
2003	1.01113	1.11%	1.01181	1.17%	1.01065	1.06%
2004	1.01006	-0.11%	0.98394	-2.79%	1.02535	1.44%
2005	1.04058	2.98%	1.03910	5.45%	1.04189	1.60%
2006	1.06516	2.33%	1.05646	1.66%	1.07049	2.71%
Average Annual Growth Rate **2002-2006**		**1.58%**		**1.37%**		**1.70%**

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Table 6

PRODUCTIVITY RESULTS: ONTARIO POWER DISTRIBUTORS

Year	Output Quantity		Input Quantity		TFP	
	Index	**Growth Rate**	**Index**	**Growth Rate**	**Index**	**Growth Rate**
2002	1.000		1.000		1.000	
2003	1.031	3.01%	1.011	1.11%	1.019	1.90%
2004	1.042	1.07%	1.010	-0.11%	1.031	1.18%
2005	1.069	2.58%	1.041	2.98%	1.027	-0.39%
2006	1.065	-0.33%	1.065	2.33%	1.000	-2.66%
Average Annual Growth Rate **2002-2006**		**1.58%**		**1.58%**		**0.01%**

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Productivity Factor (Con't)

<u>TFP Results</u>

Results show that TFP was essentially flat between 2002 and 2006

However, PEG believes current data limitations reduce the accuracy and reliability of these TFP trends

Productivity Factor (Con't)

<u>US Index-based TFP Trends</u>

PEG also estimated TFP trends for US industry

Similar methods as for Ontario although:

- Three inputs (data exists on labor – non-labor split of OM&A)
- 1964 benchmark value for capital stock

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Table 7

SAMPLED POWER DISTRIBUTORS FOR TFP TREND RESEARCH

Alabama Power	Northern Indiana Public Service
Appalachian Power	Northern States Power
Arizona Public Service	Ohio Edison
Atlantic City Electric	Ohio Power
Avista	Oklahoma Gas and Electric
Baltimore Gas & Electric	Orange and Rockland Utilities
Black Hills Power	Otter Tail Power
Boston Edison	Pacific Gas & Electric
Carolina Power & Light	PacifiCorp
Central Hudson Gas & Electric	Potomac Edison
Central Illinois Light	Potomac Electric Power
Central Maine Power	PSI Energy
Central Vermont Public Service	Public Service of Colorado
Cincinnati Gas & Electric	Public Service of New Hampshire
CLECO	Public Service of Oklahoma
Cleveland Electric Illuminating	Public Service Electric & Gas
Columbus Southern Power	Rochester Gas and Electric
Duke Power	San Diego Gas & Electric
Edison Sault Electric	South Carolina Electric & Gas
El Paso Electric	Southern California Edison
Empire District Electric	Southern Indiana Gas & Electric
Florida Power & Light	Southwestern Electric Power
Florida Power	Southwestern Public Service
Idaho Power	Tampa Electric
Kansas City Power & Light	Toledo Edison
Kansas Gas & Electric	Tuscon Electric Power
Kentucky Power	Union Light Heat & Power
Kentucky Utilities	United Illuminating
Kingsport Power	Virginia Electric & Power
Louisville Gas and Electric	West Penn Power
Madison Gas and Electric	Western Massachusetts Electric
Maine Public Service	Wisconsin Electric Power
Mississippi Power	Wisconsin Power and Light
Mount Carmel Public Utility	Wisconsin Public Service
Nevada Power	

Number of Companies: 69

Table 8

OUTPUT QUANTITY INDEXES: U.S. SAMPLE

Year	Summary Index	Quantity Subindexes	
		Customer Numbers	Deliveries
1988	1.000	1.000	1.000
1989	1.040	1.037	1.046
1990	1.060	1.057	1.066
1991	1.077	1.071	1.087
1992	1.089	1.085	1.094
1993	1.111	1.100	1.130
1994	1.131	1.116	1.155
1995	1.152	1.133	1.184
1996	1.171	1.148	1.211
1997	1.190	1.168	1.229
1998	1.213	1.185	1.262
1999	1.233	1.204	1.285
2000	1.260	1.224	1.322
2001	1.272	1.244	1.322
2002	1.291	1.259	1.346
2003	1.309	1.278	1.364
2004	1.333	1.298	1.395
2005	1.357	1.316	1.429
2006	1.371	1.337	1.430
Average Annual Growth Rate **1988-2006**	**1.75%**	**1.61%**	**1.99%**

Table 9

INPUT QUANTITY INDEXES: U.S. SAMPLE

Year	Summary Index	Input Quantity Subindexes: Labor	Materials & Services	Capital
1988	1.000	1.000	1.000	1.000
1989	1.020	1.003	1.020	1.026
1990	1.037	0.988	1.049	1.049
1991	1.064	0.988	1.118	1.071
1992	1.068	0.978	1.090	1.090
1993	1.106	1.003	1.191	1.108
1994	1.114	0.948	1.255	1.123
1995	1.115	0.918	1.258	1.135
1996	1.128	0.908	1.314	1.144
1997	1.123	0.846	1.336	1.154
1998	1.145	0.837	1.437	1.164
1999	1.157	0.841	1.455	1.177
2000	1.158	0.813	1.470	1.185
2001	1.150	0.771	1.448	1.195
2002	1.153	0.747	1.483	1.202
2003	1.181	0.769	1.558	1.216
2004	1.173	0.753	1.510	1.224
2005	1.191	0.772	1.560	1.232
2006	1.205	0.797	1.586	1.237
Average Annual Growth Rate **1988-2006**	**1.04%**	**-1.26%**	**2.56%**	**1.18%**

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Table 10

INPUT PRICE INDEXES: U.S. SAMPLE

Year	Summary Index	Input Quantity Subindexes: Labor	Materials & Services	Capital
1988	1.000	1.000	1.000	1.000
1989	1.051	1.043	1.038	1.058
1990	1.100	1.094	1.078	1.110
1991	1.151	1.141	1.115	1.168
1992	1.180	1.182	1.141	1.194
1993	1.230	1.224	1.167	1.258
1994	1.368	1.263	1.191	1.478
1995	1.420	1.297	1.216	1.548
1996	1.453	1.335	1.238	1.584
1997	1.488	1.377	1.259	1.623
1998	1.485	1.427	1.273	1.596
1999	1.575	1.473	1.291	1.731
2000	1.501	1.539	1.319	1.568
2001	1.414	1.603	1.351	1.389
2002	1.474	1.659	1.374	1.469
2003	1.607	1.720	1.403	1.669
2004	1.644	1.787	1.443	1.698
2005	1.798	1.841	1.489	1.927
2006	1.925	1.893	1.536	2.111
Average Annual Growth Rate **1988-2006**	**3.64%**	**3.54%**	**2.38%**	**4.15%**

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Table 11

PRODUCTIVITY RESULTS: U.S. SAMPLE

Year	Output Quantity Index	Input Quantity Index	TFP Index
1988	1.000	1.000	1.000
1989	1.040	1.020	1.020
1990	1.060	1.037	1.022
1991	1.077	1.064	1.012
1992	1.089	1.068	1.020
1993	1.111	1.106	1.005
1994	1.131	1.114	1.015
1995	1.152	1.115	1.033
1996	1.171	1.128	1.038
1997	1.190	1.123	1.060
1998	1.213	1.145	1.060
1999	1.233	1.157	1.066
2000	1.260	1.158	1.088
2001	1.272	1.150	1.107
2002	1.291	1.153	1.119
2003	1.309	1.181	1.109
2004	1.333	1.173	1.136
2005	1.357	1.191	1.139
2006	1.371	1.205	1.138
Average Annual Growth Rate **1988-2006**	**1.75%**	**1.04%**	**0.72%**

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Productivity Factor (Con’t)

PEG also compared US and Ontario TFP growth

Necessary to make some assumptions about Ontario TFP growth during 1997-2002 “missing years”

PEG considered four scenarios

Table 12

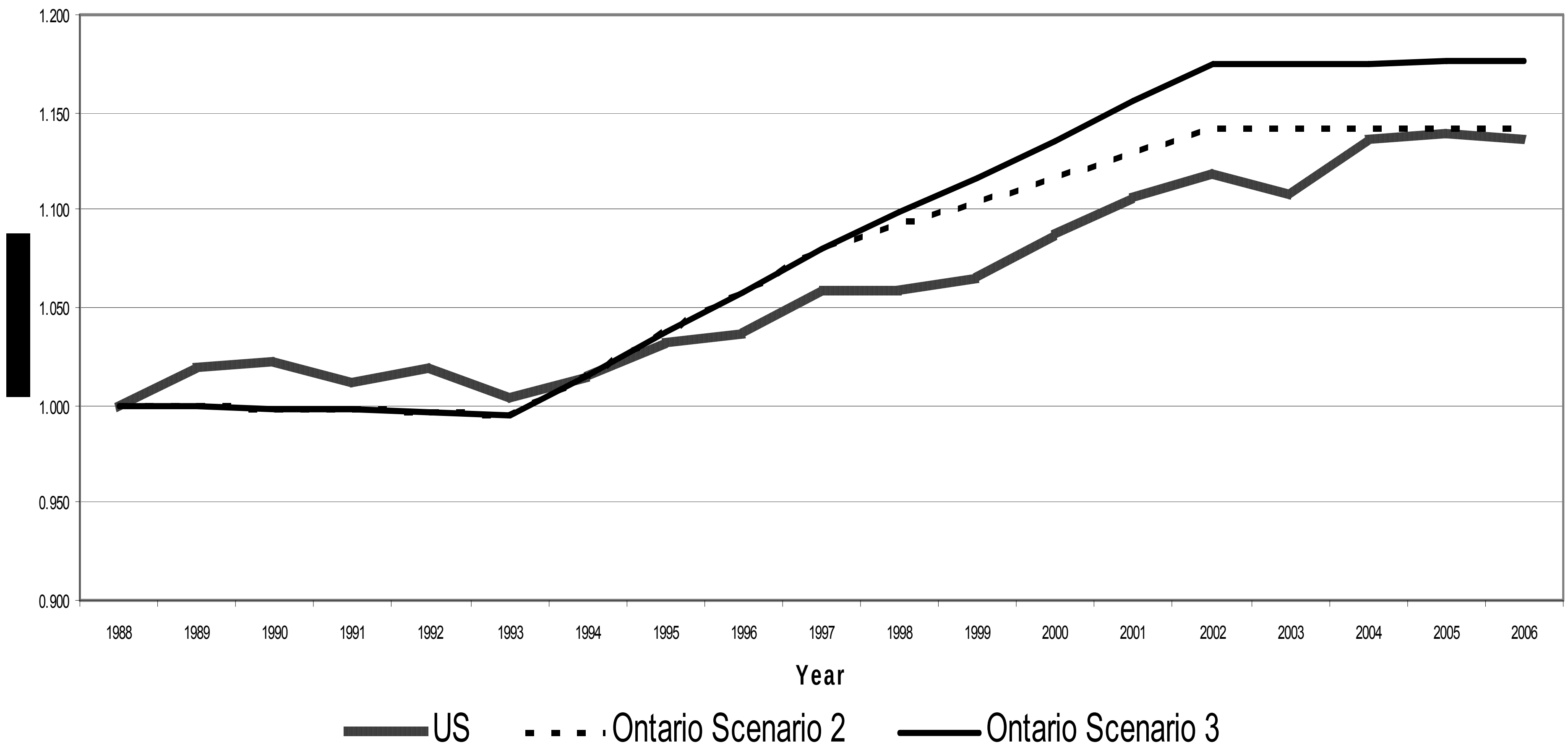
Comparison of US and Ontario Electricity Distribution TFP Growth

	TFP Growth				
	Ontario 1 [a]	Ontario 2 [b]	Ontario 3 [c]	Ontario 4 [d]	United States
1988	1.000	1.000	1.000	1.000	1.000
1989	0.999	0.999	0.999	0.999	1.020
1990	0.998	0.998	0.998	0.998	1.022
1991	0.997	0.997	0.997	0.997	1.012
1992	0.996	0.996	0.996	0.996	1.020
1993	0.995	0.995	0.995	0.995	1.005
1994	1.016	1.016	1.016	1.016	1.015
1995	1.037	1.037	1.037	1.037	1.033
1996	1.059	1.059	1.059	1.059	1.038
1997	1.080	1.080	1.080	1.080	1.060
1998	1.080	1.092	1.099	1.103	1.060
1999	1.080	1.104	1.117	1.126	1.066
2000	1.080	1.116	1.136	1.149	1.088
2001	1.080	1.129	1.156	1.173	1.107
2002	1.080	1.141	1.175	1.197	1.119
2003	1.081	1.141	1.175	1.197	1.109
2004	1.081	1.141	1.175	1.197	1.136
2005	1.081	1.141	1.176	1.197	1.139
2006	1.081	1.141	1.176	1.198	1.138
1988 - 2006	0.43%	0.74%	0.90%	1.00%	0.72%
1988 - 1993	-0.09%	-0.09%	-0.09%	-0.09%	0.09%
1993 - 1997	2.05%	2.05%	2.05%	2.05%	1.33%
1997 - 2002	0.00%	1.09%	1.68%	2.05%	1.09%
2002 - 2006	0.01%	0.01%	0.01%	0.01%	0.41%

	Difference between Ontario and US TFP Growth Rates			
	Ontario 1 [a]	Ontario 2 [b]	Ontario 3 [c]	Ontario 4 [d]
1988 - 2006	-0.28%	0.02%	0.18%	0.29%
1988 - 1993	-0.19%	-0.19%	-0.19%	-0.19%
1993 - 1997	0.72%	0.72%	0.72%	0.72%
1997 - 2002	-1.09%	0.00%	0.58%	0.96%
2002 - 2006	-0.40%	-0.40%	-0.40%	-0.40%

[a] Assumes 0% TFP growth 1997 - 2002.
[b] Assumes Ontario TFP growth equal to US TFP growth 1997 - 2002.
[c] Assumes Ontario TFP growth 1997 - 2002 maintains proportion relative to US TFP growth from 1993 - 1997.
[d] Assumes TFP growth 1997 - 2002 matches 2.05% rate as in 1993 - 1997.

Comparative TFP Experience
US and Ontario Power Distributors



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Productivity Factor (Con't)

PEG believes data show US TFP growth a reasonable proxy for Ontario

TFP trend estimated over 1995-2006 period based on our "start date analysis"

This TFP trend – and our originally recommended productivity factor for IRM3 – is 0.88% pa

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Table 13

Start Date Analysis for Determining Long Run TFP Trend

Year	Heating Degree Days	Cooling Degree Days	Unemployment Rate	% Difference from 2006 Conditions
1990	4,016	1,260	5.6	-1.44%
1991	4,200	1,331	6.9	-1.62%
1992	4,441	1,040	7.5	-3.07%
1993	4,700	1,218	6.9	-1.72%
1994	4,483	1,220	6.1	-1.50%
1995	4,531	1,293	5.6	-0.87%
1996	4,713	1,180	5.4	-1.13%
1997	4,542	1,156	4.9	-1.08%
1998	3,951	1,410	4.5	-0.18%
1999	4,169	1,297	4.2	-0.25%
2000	4,460	1,229	4.0	-0.17%
2001	4,223	1,245	4.7	-0.79%
2002	4,284	1,393	5.8	-0.75%
2003	4,460	1,290	6.0	-1.15%
2004	4,224	1,260	5.5	-1.20%
2005	4,290	1,232	5.1	-1.02%
2006	4,315	1,397	4.6	0.00%

Coefficients	lhdd	lcdd	lur
Parameters	0.0352	0.0563	-0.0309
T-statistic	5.0607	7.6498	-1.8291

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Productivity Factor (Con't)

Several critiques of PEG's recommended productivity factor

1. Not enough weight on Ontario and/or recent experience
2. Ignores increasing cost pressures in Ontario
3. Inherent slowdown in TFP over time
4. Precedents in Ontario
5. Choice of outputs – immediate and longer-term

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Productivity Factor (Con't)

Ontario Experience

Must be recognized that PEG has objectively evaluated all available TFP evidence for Ontario industry

Our report details several reasons why an objective review does not support the use of 2002-06 Ontario TFP trends for IRM3 (*e.g.* pp 4-5,30-31,43-46)

The critiques have largely (and sometimes entirely) ignored those reasons – but they remain valid

Productivity Factor (Con't)

<u>Ontario Experience</u>

1. Identifiable downward biases in available TFP evidence
   - lack of volumes in IRM1 TFP estimate
   - anomalous output decline in Ontario in 2006
2. Lack of historical capital additions data
3. Transitional cost pressures in 2002-06 may not persist on ongoing, *rate of change* basis
4. Four years not long enough period to compute reliable TFP estimate

   >> supported by actual TFP trends estimated for Ontario in 1988-93 vs. 1993-97

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Productivity Factor (Con't)

<u>Increasing Cost Pressures</u>

Claimed that there will be ongoing cost pressures similar to those in 2002-06

But no evidence has been presented that these cost pressures will be sustained on a rate of change basis and therefore relevant to rate *adjustments* rather than rate *levels* established at rebasing

Other factors may create or accelerate downward cost pressures during IRM3

- Merger savings
- Operational benefits from smart meters

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Productivity Factor (Con't)

<u>Inherent Slowdown in TFP Growth</u>

Argued that the lower TFP growth for US distributors in 2002-06 also demonstrates that industry TFP is slowing

But this ignores the role of changing pension contributions on the US industry's growth – a transitory and not long-run factor

Generally slowing TFP growth is also contradicted by Ontario TFP experience (*i.e.* TFP growth greater in 93-97 than 88-93)

>> Both factors demonstrate the importance, and necessity, of measuring TFP over a long enough period so that it is not distorted by transitory factors

Productivity Factor (Con't)

<u>OEB Precedents</u>

IRM1 put greater weight on recent TFP trends, and it is argued that this precedent should also apply in IRM3

But placing more weight on recent TFP trends was a one-time decision that the Board did not repeat in

- Enbridge targeted PBR
- Union Gas PBR
- IRM2
- Most recent Gas IRM

IRM1 therefore not "precedent setting," Ontario precedents since then have been quite varied

PEG's method for recommending a TFP trend provides a more rigorous and transparent method for calculating the TFP trend

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Productivity Factor (Con't)

<u>Choice of Outputs</u>

LEI argues that peak demand should be added as an output, but doing so in 2002-2006 period will *introduce* biases not "correct errors" (*e.g.* footnote 63, p. 79 LEI comments)

LEI's TFP measure also uses km of line to measure capital

Flat out wrong - such a capital measure is contradicted by

- Economic theory
- All empirical evidence
- Industry experience
- Regulatory precedents

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Productivity Factor (Con't)

<u>Choice of Outputs (Con't)</u>

LEI also recommends a long-run project to develop new, MVA-km based outputs

This recommendation is conceptually incorrect

In a TFP study used in a price indexing PBR plan, appropriate outputs are billing determinants, not an engineering based notional output with no connection to distributor revenues

Productivity Factor (Con't)

Critiques of PEG recommendation have been considered either in previous PEG report or March stakeholder conference

Critiques have largely (sometimes entirely) ignored PEG's response to these substantive concerns

Considering all available evidence, PEG continues to believe our initial recommendation of 0.88% is the most objective estimate for a productivity factor

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Inflation Factor Differential and Inflation

Staff's original proposal was to use an industry price index (IPI) as the inflation factor

Some stakeholders expressed concern over details of Staff's illustrative IPI

Staff's updated proposal is to use an industry-wide inflation measure (*e.g.* the GDP-FDD) as the inflation factor

Inflation Factor (Con't)

An economy-wide inflation factor raises the issue of the inflation differential to be included in the X factor

The inflation differential is designed to make the rate adjustment mechanism better track industry input price trends

Indexing logic shows the proper value of the inflation differential depends on the relationship between the proposed inflation factor and the IPI

>> not necessary to implement a "differential of differentials" X factor

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Inflation Factor (Con't)

PEG examined this relationship using both Ontario and US data

Two Ontario IPIs examined

- Staff's proposal
- Slight modification with GDP-FDD used as the materials price subindex

PEG's February report presented sufficient data to examine this issue in U.S.

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Price Trends: IPI and GDP-FDD

Year	IPI[1]	IPI Smoothed[2]	IPI2[3]	IPI2 Smoothed[4]	GDP FDD CAN
1988	0.96		0.974		3.68%
1989	0.98		1.003		4.41%
1990	1.06	0.98	1.081	0.995	3.76%
1991	1.02	0.99	1.040	1.012	3.39%
1992	1.00	0.99	1.020	1.014	1.75%
1993	0.98	0.97	1.001	0.987	2.04%
1994	1.06	0.98	1.075	0.995	1.48%
1995	1.10	1.01	1.112	1.023	1.14%
1996	1.06	1.03	1.076	1.047	1.13%
1997	1.02	1.02	1.035	1.037	1.52%
1998	1.01	1.00	1.017	1.010	1.30%
1999	1.04	0.99	1.053	1.003	1.30%
2000	1.08	1.01	1.090	1.025	2.40%
2001	1.09	1.04	1.098	1.051	1.80%
2002	1.09	1.06	1.107	1.067	2.30%
2003	1.07	1.05	1.095	1.069	1.50%
2004	1.07	1.05	1.098	1.071	1.70%
2005	1.05	1.04	1.081	1.064	2.10%
2006	1.10	1.04	1.125	1.074	2.00%
2007	1.13	1.06	1.166	1.099	2.10%
Average Growth Rates	0.86%	0.46%	0.95%	0.58%	2.14%

1. IPI as constructed by Staff and presented in Staff Proposal.

2. Same as IPI Except capital price sub-index is computed as a three year moving average rather than as annual rate of change.

3. Same as Staff IPI except GDP-FDD is the materials price sub-index.

4. Same as IPI2 except GDP-FDD is the materials price sub-index.

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Inflation Differential Ontario

Year	%ΔGDP CAN	%Δ IPI 1	%Δ IPI 2	Differential 1	Differential 2
1991	3.39%	1.02%	1.69%	2.37%	1.70%
1992	1.75%	0.00%	0.20%	1.75%	1.55%
1993	2.04%	-2.04%	-2.70%	4.08%	4.74%
1994	1.48%	1.03%	0.81%	0.45%	0.67%
1995	1.14%	3.02%	2.78%	-1.88%	-1.64%
1996	1.13%	1.96%	2.32%	-0.83%	-1.19%
1997	1.52%	-0.98%	-0.96%	2.50%	2.48%
1998	1.30%	-1.98%	-2.64%	3.28%	3.94%
1999	1.30%	-1.01%	-0.70%	2.31%	2.00%
2000	2.40%	2.00%	2.17%	0.40%	0.23%
2001	1.80%	2.93%	2.50%	-1.13%	-0.70%
2002	2.30%	1.90%	1.51%	0.40%	0.79%
2003	1.50%	-0.95%	0.19%	2.45%	1.31%
2004	1.70%	0.00%	0.19%	1.70%	1.51%
2005	2.10%	-0.96%	-0.66%	3.06%	2.76%
2006	2.00%	0.00%	0.94%	2.00%	1.06%
Averages					
1991-06	**1.70%**	**0.33%**	**0.40%**	**1.37%**	**1.30%**
1991-93	1.90%	-1.02%	-1.25%	2.92%	3.15%
1993-97	1.32%	1.26%	1.24%	0.06%	0.08%
1997-02	1.82%	0.77%	0.57%	1.05%	1.25%
2002-06	1.83%	-0.48%	0.16%	2.30%	1.66%

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Table 10

INPUT PRICE INDEXES: U.S. SAMPLE

Year	Summary Index	Input Quantity Subindexes: Labor	Input Quantity Subindexes: Materials & Services	Input Quantity Subindexes: Capital
1988	1.000	1.000	1.000	1.000
1989	1.051	1.043	1.038	1.058
1990	1.100	1.094	1.078	1.110
1991	1.151	1.141	1.115	1.168
1992	1.180	1.182	1.141	1.194
1993	1.230	1.224	1.167	1.258
1994	1.368	1.263	1.191	1.478
1995	1.420	1.297	1.216	1.548
1996	1.453	1.335	1.238	1.584
1997	1.488	1.377	1.259	1.623
1998	1.485	1.427	1.273	1.596
1999	1.575	1.473	1.291	1.731
2000	1.501	1.539	1.319	1.568
2001	1.414	1.603	1.351	1.389
2002	1.474	1.659	1.374	1.469
2003	1.607	1.720	1.403	1.669
2004	1.644	1.787	1.443	1.698
2005	1.798	1.841	1.489	1.927
2006	1.925	1.893	1.536	2.111
Average Annual Growth Rate **1988-2006**	**3.64%**	**3.54%**	**2.38%**	**4.15%**

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US Inflation Differential

Year	US GDPPI	US IPI	Differential
1988			
1989	3.71%	4.93%	-1.22%
1990	3.78%	4.57%	-0.79%
1991	3.40%	4.56%	-1.16%
1992	2.26%	2.50%	-0.24%
1993	2.26%	4.19%	-1.92%
1994	2.09%	10.57%	-8.49%
1995	2.02%	3.74%	-1.73%
1996	1.87%	2.30%	-0.43%
1997	1.63%	2.38%	-0.74%
1998	1.10%	-0.20%	1.30%
1999	1.43%	5.88%	-4.45%
2000	2.14%	-4.80%	6.94%
2001	2.36%	-5.97%	8.33%
2002	1.72%	4.17%	-2.44%
2003	2.09%	8.65%	-6.56%
2004	2.81%	2.26%	0.54%
2005	3.17%	8.96%	-5.79%
2006	3.09%	6.78%	-3.70%
Averages			
1988-06	**2.38%**	**3.64%**	**-1.25%**
1988-93	3.08%	4.15%	-1.06%
1993-97	1.90%	4.75%	-2.85%
1997-02	1.75%	-0.18%	1.94%
2002-06	2.79%	6.66%	-3.88%

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Comparison of US & Ontario Inflation Differentials

Year	Ontario Differential 1	Ontario Differential 2	US Differential
1991	2.37%	1.70%	-1.16%
1992	1.75%	1.55%	-0.24%
1993	4.08%	4.74%	-1.92%
1994	0.45%	0.67%	-8.49%
1995	-1.88%	-1.64%	-1.73%
1996	-0.83%	-1.19%	-0.43%
1997	2.50%	2.48%	-0.74%
1998	3.28%	3.94%	1.30%
1999	2.31%	2.00%	-4.45%
2000	0.40%	0.23%	6.94%
2001	-1.13%	-0.70%	8.33%
2002	0.40%	0.79%	-2.44%
2003	2.45%	1.31%	-6.56%
2004	1.70%	1.51%	0.54%
2005	3.06%	2.76%	-5.79%
2006	2.00%	1.06%	-3.70%
Averages			
1991-06	**1.37%**	**1.30%**	**-1.29%**
1991-93	2.92%	3.15%	-1.06%
1993-97	0.06%	0.08%	-2.85%
1997-02	1.05%	1.25%	1.94%
2002-06	2.30%	1.66%	-3.88%

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Inflation Differential (Con't)

The evidence from the US and Ontario suggests highly divergent inflation differentials

Given the empirical uncertainty, PEG believes the best estimate of inflation differential for IRM3 is zero

Staff's proposed Off-ramp will provide some "backstop" protection against input prices

Longer-term investigation of IPI – and differentials between IPI and broader inflation measures – is important and can provide a foundation for sustainable IRMs

Consumer Dividends

Consumer dividends often vary by company

>> “company specific” and “future” productivity factor

Consumer dividend values almost always determined through judgment

Approved dividends are between 0 and 1%, with an average value of about 0.5%

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Consumer Dividends (Con't)

Benchmarking sometimes used to inform judgment

Basic ideas:

Relatively less efficient company →

More fat to cut →

Greater scope for incremental TFP gains →

Higher consumer dividend

And vice versa

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Consumer Dividends (Con’t)

Setting consumer dividends with a reasonable, empirical basis probably most challenging aspect of IRM3

PEG originally proposed five consumer dividends between 0 and 0.6%

PEG’s OM&A comparative cost analysis was used to assign companies to one of five groups and recommended consumer dividend levels

Consumer Dividends (Con't)

Some criticisms of PEG's consumer dividend proposal

1. No empirical evidence of differences in efficiency
2. Consumer dividends valid only immediately after transition from cost of service regulation
3. Not appropriate to benchmark OM&A only
4. OM&A benchmarking can distort company incentives
5. Dividend values should be negative as well as positive, and are better described as "diversity factors"

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Consumer Dividends (Con't)

<u>No empirical evidence of differences in efficiency</u>

Not true – Tables 16, 17, and 18 in PEG report show a wide diversity in efficiency levels among Ontario distributors

Should not simply be assumed that being under incentive regulation makes all companies equally efficient

Also not clear that Ontario <u>has</u> been under IR since 2000

- a number of "fits and starts" with IR
- framework has not been as predictable or sustainable as Board would like
- such predictability critical for undertaking long-term initiatives that can improve performance

Table 16

Effects of Cost Performance: Translog & Double Log Models

	Years Benchmarked	Translog Model					Double Log Model				
		Actual/Predicted [A]	Deviation Percentage [A-1]	P-Value	Excess Cost in $	Rank	Actual/Predicted [A]	Deviation Percentage [A-1]	P-Value	Excess Cost in $	Rank
Hydro 2000	2002-2005	0.686	-0.314	0.096	-74,601	1	0.647	-0.353	0.089	-88,784	1
Hydro One Brampton Networks	2002-2005	0.707	-0.293	0.001	-5,556,551	2	0.757	-0.243	0.012	-4,278,375	9
Hydro Hawkesbury	2002-2005	0.714	-0.286	0.007	-262,382	3	0.654	-0.346	0.000	-346,746	2
Newbury Power	2002-2005	0.717	-0.283	0.110	-16,382	4	0.835	-0.165	0.249	-8,156	16
Hearst Power	2002-2005	0.733	-0.267	0.011	-186,012	5	0.721	-0.279	0.005	-197,236	4
Kitchener-Wilmot Hydro	2002-2005	0.736	-0.264	0.001	-3,356,860	6	0.727	-0.273	0.001	-3,510,160	5
Tay Hydro Electric	2002-2005	0.767	-0.233	0.104	-392,542	7	0.703	-0.297	0.013	-307,747	3
Lakefront Utilities	2002-2004	0.767	-0.233	0.014	-221,328	8	0.819	-0.181	0.131	-286,424	14
Lakeland Power	2002-2005	0.773	-0.227	0.014	-565,560	9	0.820	-0.180	0.046	-422,585	15
Port Colborne (CNP)	2002-2005	0.775	-0.225	0.052	-416,948	10	0.751	-0.249	0.031	-475,272	8
Barrie Hydro	2002-2005	0.789	-0.211	0.054	-2,070,698	11	0.748	-0.252	0.031	-2,627,633	7
Grimsby Power	2002-2005	0.801	-0.199	0.045	-326,436	12	0.735	-0.265	0.006	-473,100	6
Cooperative Hydro Embrun	2002-2005	0.806	-0.194	0.026	-72,437	13	0.886	-0.114	0.167	-38,644	22
Cambridge & North Dumfries	2002-2005	0.811	-0.189	0.024	-1,649,361	14	0.842	-0.158	0.062	-1,331,706	17
Niagara-on-the-Lake Hydro	2002-2005	0.813	-0.187	0.028	-291,049	15	0.817	-0.183	0.042	-283,286	13
Chatham-Kent Hydro	2004-2005	0.818	-0.182	0.021	-1,045,214	16	0.807	-0.193	0.023	-1,131,966	12
Renfrew Hydro	2002-2005	0.827	-0.173	0.046	-150,659	17	0.775	-0.225	0.011	-208,202	11
Orangeville Hydro	2002-2005	0.849	-0.151	0.069	-294,264	18	0.905	-0.095	0.205	-171,832	25
E.L.K. Energy	2002-2005	0.874	-0.126	0.166	-242,263	19	0.937	-0.063	0.282	-114,357	30
Festival Hydro	2002-2005	0.875	-0.125	0.165	-423,298	20	0.878	-0.122	0.134	-409,824	20
Halton Hills Hydro	2002-2005	0.877	-0.123	0.107	-524,215	21	0.849	-0.151	0.093	-663,047	18
Wasaga Distribution	2002-2005	0.906	-0.094	0.158	-133,289	22	0.763	-0.237	0.025	-398,683	10
Fort Frances Power	2002-2005	0.907	-0.093	0.177	-93,677	23	0.863	-0.137	0.099	-144,073	19
Burlington Hydro	2002-2005	0.908	-0.092	0.171	-969,802	24	0.901	-0.099	0.170	-1,043,495	23
Hydro Ottawa	2002-2005	0.917	-0.083	0.096	-3,415,957	25	0.907	-0.093	0.093	-3,869,409	26
Guelph Hydro Electric Systems	2002-2005	0.931	-0.069	0.258	-554,396	26	0.977	-0.023	0.409	-175,301	40
Milton Hydro Distribution	2002-2005	0.934	-0.066	0.232	-85,131	27	0.944	-0.056	0.263	-212,953	31
Kenora Hydro Electric	2002-2005	0.934	-0.066	0.248	-250,934	28	0.950	-0.050	0.318	-63,302	33
St. Thomas Energy	2002-2005	0.940	-0.060	0.285	-159,655	29	0.965	-0.035	0.287	-93,043	35
Ottawa River Power	2002-2004	0.941	-0.059	0.298	-116,515	30	0.984	-0.016	0.358	-29,877	41
Peterborough Distribution	2002-2005	0.943	-0.057	0.280	-310,031	31	0.923	-0.077	0.233	-424,870	27
Oakville Hydro Electricity Distribution	2002-2005	0.947	-0.053	0.260	-511,115	32	0.993	-0.007	0.351	-73,990	42
Powerstream	2002-2005	0.954	-0.046	0.254	-1,610,386	33	0.974	-0.026	0.300	-847,161	37
West Perth Power	2002-2005	0.960	-0.040	0.061	-18,665	34	0.976	-0.024	0.080	-10,833	38
Waterloo North Hydro	2002-2005	0.966	-0.034	0.370	-291,019	35	0.967	-0.033	0.359	-282,562	36
Horizon Utilities	2002-2005	0.968	-0.032	0.252	-1,084,526	36	0.931	-0.069	0.235	-2,341,089	28
London Hydro	2002-2005	0.969	-0.031	0.383	-639,711	37	1.006	0.006	0.449	121,541	43
Espanola Regional Hydro Distribution	2003-2005	0.972	-0.028	0.197	-22,663	38	0.935	-0.065	0.129	-55,305	29
North Bay Hydro Distribution	2002-2005	0.974	-0.026	0.287	-118,142	39	0.905	-0.095	0.250	-485,664	24
Northern Ontario Wires	2002-2005	0.988	-0.012	0.370	-20,809	40	0.962	-0.038	0.314	-68,554	34
Haldimand County Hydro	2002-2005	0.990	-0.010	0.180	-50,003	41	1.169	0.169	0.084	718,639	67
Welland Hydro-Electric System	2002-2005	1.004	0.004	0.304	14,729	42	1.009	0.009	0.320	33,056	44
COLLUS Power	2002-2005	1.008	0.008	0.384	19,608	43	0.977	-0.023	0.404	-57,254	39
Innisfil Hydro Distribution Systems	2002-2005	1.022	0.022	0.163	53,493	44	0.884	-0.116	0.147	-321,759	21
Sioux Lookout Hydro	2002-2005	1.022	0.022	0.181	17,860	45	0.945	-0.055	0.182	-49,012	32
Woodstock Hydro Services	2002-2005	1.024	0.024	0.403	65,012	46	1.057	0.057	0.313	146,709	50
Clinton Power	2002-2005	1.025	0.025	0.364	8,369	47	1.161	0.161	0.146	48,855	65
PUC Distribution	2002-2005	1.034	0.034	0.188	196,030	48	1.023	0.023	0.250	141,529	45
West Nipissing Energy Services	2002-2005	1.041	0.041	0.311	28,231	49	1.051	0.051	0.311	35,115	49

Table 16, continued

Effects of Cost Performance: Translog & Double Log Models

	Years Benchmarked	Translog Model: Actual/Predicted [A]	Translog Model: Deviation from Sample Mean [A]-1	Translog Model: P-Value	Translog Model: Excess Cost in $	Translog Model: Rank	Double Log Model: Actual/Predicted [A]	Double Log Model: Deviation from Sample Mean [A]-1	Double Log Model: P-Value	Double Log Model: Excess Cost in $	Double Log Model: Rank
Parry Sound Power	2002-2005	1.042	0.042	0.197	34,146	50	1.061	0.061	0.207	48,700	51
Middlesex Power Distribution	2002-2005	1.043	0.043	0.143	55,658	51	1.076	0.076	0.141	95,266	55
Rideau St. Lawrence Distribution	2002-2005	1.058	0.058	0.290	62,738	52	1.074	0.074	0.259	78,955	54
Grand Valley Energy	2002-2005	1.059	0.059	0.314	9,442	53	1.273	0.273	0.028	36,496	74
Norfolk Power Distribution	2002-2005	1.067	0.067	0.264	240,460	54	1.067	0.067	0.263	240,460	53
Brantford Power	2002-2005	1.076	0.076	0.246	433,404	55	1.102	0.102	0.212	569,121	59
Orillia Power Distribution	2002-2005	1.078	0.078	0.191	189,182	56	1.081	0.081	0.194	198,879	58
Bluewater Power Distribution	2002-2005	1.080	0.080	0.248	523,764	57	1.112	0.112	0.172	710,804	60
Greater Sudbury Hydro	2002-2005	1.083	0.083	0.242	243,158	58	1.063	0.063	0.295	483,001	52
Fort Erie (CNP)	2002-2005	1.083	0.083	0.146	627,525	59	1.050	0.050	0.199	149,442	48
Terrace Bay Superior Wires	2002-2005	1.084	0.084	0.195	21,600	60	1.046	0.046	0.240	12,481	47
Great Lakes Power	2002-2005	1.096	0.096	0.133	540,205	61	1.640	0.640	0.000	2,378,666	83
Newmarket Hydro	2002-2005	1.097	0.097	0.259	453,026	62	1.112	0.112	0.265	513,062	61
Dutton Hydro	2002-2005	1.099	0.099	0.282	13,588	63	1.314	0.314	0.094	36,182	76
Thunder Bay Hydro Electricity Distribution	2002-2005	1.116	0.116	0.139	1,071,135	64	1.076	0.076	0.260	723,913	56
Whitby Hydro Electric	2002, 2003, 2005	1.117	0.117	0.149	690,926	65	1.037	0.037	0.354	238,881	46
Kingston Electricity Distribution	2003-2005	1.137	0.137	0.113	584,554	66	1.134	0.134	0.120	575,912	63
Wellington North Power	2002-2005	1.138	0.138	0.109	102,360	67	1.079	0.079	0.253	61,896	57
Enersource Hydro Mississauga	2002-2004	1.143	0.143	0.116	4,460,773	68	1.200	0.200	0.055	5,918,723	71
Peninsula West Utilities	2002-2005	1.143	0.143	0.227	488,834	69	1.123	0.123	0.217	423,960	62
Centre Wellington Hydro	2002-2005	1.181	0.181	0.111	215,739	70	1.185	0.185	0.091	221,737	69
Westario Power	2002-2005	1.188	0.188	0.082	651,887	71	1.183	0.183	0.099	641,385	68
Eastern Ontario Power (CNP)	2002-2005	1.192	0.192	0.130	177,762	72	1.165	0.165	0.190	155,462	66
Niagara Falls Hydro	2002-2005	1.228	0.228	0.021	1,312,580	73	1.259	0.259	0.016	1,449,386	73
Toronto Hydro-Electric System	2002-2005	1.232	0.232	0.027	26,111,812	74	1.365	0.365	0.003	37,005,031	79
Essex Powerlines	2002-2005	1.259	0.259	0.024	1,138,847	75	1.224	0.224	0.053	1,013,796	72
Veridian Connections	2002-2005	1.280	0.280	0.038	4,341,254	76	1.190	0.190	0.151	3,167,842	70
ENWIN Powerlines	2002-2005	1.292	0.292	0.040	4,529,632	77	1.487	0.487	0.001	6,571,413	82
West Coast Huron Energy	2002-2005	1.301	0.301	0.013	264,103	78	1.405	0.405	0.006	328,077	80
Brant County Power	2002-2005	1.318	0.318	0.024	626,533	79	1.322	0.322	0.024	630,455	77
Tillsonburg Hydro	2002-2005	1.339	0.339	0.079	328,599	80	1.146	0.146	0.177	165,491	64
Chapleau Public Utilities	2002-2005	1.361	0.361	0.009	123,784	81	1.358	0.358	0.008	123,097	78
Midland Power Utility	2002-2005	1.430	0.430	0.018	481,871	82	1.302	0.302	0.026	370,681	75
Erie Thames Powerlines	2002-2005	1.435	0.435	0.002	1,128,102	83	1.428	0.428	0.007	1,115,095	81

The following companies were excluded due to mergers: Asphodel Norwood Distribution, Aurora Hydro Connections, Gravenhurst Hydro Electric, Guelph Hydro Electric Systems (without Wellington Electric Distribution), Hamilton Hydro, Lakefield Distribution, Peterborough Distribution (without Asphodel Norwood and Lakefield), Powerstream (without Aurora), Scugog Hydro Energy, St. Catherines Hydro Utility Services, Veridian Connections (without Gravenhurst Hydro Electric and Scugog), and Wellington Electric Distribution

These companies were excluded from the sample due to missing or inaccurate data: Oshawa, PUC Networks (no retail volumes reported), Hydro One Networks (no deliveries to other LDCs reported), and Atikokan Hydro (zero underground plant reported).

Table 17

Unit Cost and Productivity Indexes for Total OM&A Expenses [1, 2]

	Average OM&A Expenses	Unit Cost (Low Values suggest good cost management.)								Productivity (High values suggest good cost management.)							
		2002	2003	2004	2005	Average of Available Years	Average / Group Average [A]	Percentage Differences [A - 1]	Excess Cost Per Year	2002	2003	2004	2005	Average of Available Years	Average / Group Average [B]	Percentage Differences [B -1]	Excess Cost Per Year
Unclassified																	
Hydro One Networks	$322,140,448	1.182	1.169	1.113	1.307	1.193	N/A	N/A	**N/A**	0.846	0.866	0.925	0.804	0.860	N/A	N/A	**N/A**
Small Northern LDCs																	
Hearst Power Distribution	$512,184	0.776	0.701	0.857	0.883	0.804	0.634	-36.6%	**-$187,428**	1.242	1.393	1.158	1.147	1.235	1.488	48.8%	**-$249,691**
Lakeland Power Distribution	$1,931,900	0.853	0.973	0.899	0.939	0.916	0.722	-27.8%	**-$536,842**	1.136	1.009	1.111	1.084	1.085	1.307	30.7%	**-$593,093**
Ottawa River Power	$1,854,822	0.965	1.082	1.065	1.034	1.037	0.817	-18.3%	**-$338,669**	0.946	0.855	0.883	0.928	0.903	1.088	8.8%	**-$162,845**
Kenora Hydro Electric	$1,210,292	1.124	1.166	1.188	1.171	1.162	0.917	-8.3%	**-$101,003**	0.872	0.851	0.849	0.879	0.863	1.040	4.0%	**-$47,871**
Sioux Lookout Hydro	$831,596	1.109	0.924	1.297	1.399	1.182	0.932	-6.8%	**-$56,304**	0.865	1.051	0.762	0.721	0.850	1.023	2.3%	**-$19,369**
Espanola Regional Hydro Distribution	$802,114	1.384	1.143	1.070	1.116	1.178	0.929	-7.1%	**-$56,908**	0.696	0.854	0.928	0.907	0.846	1.019	1.9%	**-$15,542**
Northern Ontario Wires	$1,725,352	1.296	1.185	1.280	1.173	1.234	0.973	-2.7%	**-$46,983**	0.753	0.834	0.785	0.874	0.812	0.978	-2.2%	**$38,601**
Fort Frances Power	$911,479	1.209	1.169	1.222	1.303	1.226	0.967	-3.3%	**-$30,455**	0.793	0.831	0.809	0.773	0.802	0.966	-3.4%	**$31,405**
Terrace Bay Superior Wires	$278,342	1.690	1.486	1.382	1.681	1.560	1.230	23.0%	**$64,033**	0.567	0.654	0.715	0.600	0.634	0.764	-23.6%	**$65,819**
Chapleau Public Utilities	$467,979	1.763	1.811	1.619	1.930	1.781	1.404	40.4%	**$189,143**	0.547	0.539	0.613	0.525	0.556	0.669	-33.1%	**$154,689**
Atikokan Hydro	$738,959	1.511	2.581	1.732	1.659	1.870	1.475	47.5%	**$350,961**	0.635	0.377	0.571	0.608	0.547	0.659	-34.1%	**$251,745**
GROUP AVERAGE						*1.268*								*0.830*			
Large Northern LDCs																	
North Bay Hydro Distribution	$4,678,187	1.029	1.063	0.995	0.867	0.989	0.773	-22.7%	**-$1,062,606**	0.913	0.896	0.974	1.139	0.980	1.179	17.9%	**-$837,108**
PUC Distribution	$6,254,896	0.880	0.936	1.089	1.085	0.997	0.780	-22.0%	**-$1,378,448**	1.068	1.017	0.889	0.910	0.971	1.167	16.7%	**-$1,046,056**
Greater Sudbury Hydro	$8,171,498	1.006	0.995	0.980	1.099	1.020	0.797	-20.3%	**-$1,655,383**	0.958	0.981	1.013	0.921	0.968	1.164	16.4%	**-$1,341,231**
Thunder Bay Hydro Electricity Dist.	$10,287,890	1.055	1.094	1.055	1.023	1.057	0.826	-17.4%	**-$1,789,708**	0.909	0.888	0.937	0.985	0.930	1.118	11.8%	**-$1,214,525**
West Nipissing Energy Services	$720,306	1.359	1.250	1.413	1.365	1.347	1.053	5.3%	**$37,956**	0.692	0.762	0.686	0.724	0.716	0.861	-13.9%	**$100,341**
Great Lakes Power	$6,100,416	2.169	2.305	2.168	2.423	2.266	1.771	77.1%	**$4,705,664**	0.433	0.413	0.446	0.407	0.425	0.511	-48.9%	**$2,983,487**
GROUP AVERAGE						*1.279*								*0.832*			
Southwestern Small Town LDCs																	
Grimsby Power	$1,314,250	0.722	0.708	0.799	0.848	0.769	0.677	-32.3%	**-$424,760**	1.392	1.438	1.295	1.245	1.342	1.431	43.1%	**-$566,194**
Niagara-on-the-Lake Hydro	$1,267,288	0.838	0.757	0.851	0.792	0.810	0.712	-28.8%	**-$364,386**	1.145	1.284	1.162	1.274	1.216	1.296	29.6%	**-$375,201**
Halton Hills Hydro	$3,744,491	0.918	0.851	0.863	0.796	0.857	0.754	-24.6%	**-$920,482**	1.102	1.204	1.208	1.335	1.212	1.292	29.2%	**-$1,094,049**
Orangeville Hydro	$1,651,565	0.895	0.964	0.829	0.907	0.899	0.791	-20.9%	**-$345,247**	1.125	1.059	1.252	1.167	1.151	1.227	22.7%	**-$374,498**
Tay Hydro Electric Distribution	$736,780	0.777	0.873	0.972	1.115	0.934	0.822	-17.8%	**-$131,108**	1.283	1.157	1.056	0.939	1.108	1.181	18.1%	**-$133,653**
COLLUS Power	$2,463,634	0.903	0.859	0.919	0.907	0.897	0.790	-21.0%	**-$518,191**	1.049	1.117	1.063	1.097	1.082	1.153	15.3%	**-$376,245**
West Perth Power	$450,079	N/A	1.251	1.224	0.766	1.080	0.951	-4.9%	**-$22,133**	N/A	0.781	0.812	1.323	0.972	1.036	3.6%	**-$16,216**
Norfolk Power Distribution	$3,826,365	1.117	1.073	0.992	0.957	1.035	0.911	-8.9%	**-$341,897**	0.863	0.911	1.001	1.059	0.959	1.022	2.2%	**-$82,806**
Peninsula West Utilities	$3,895,811	1.018	1.019	1.200	1.257	1.124	0.989	-1.1%	**-$43,211**	0.987	0.998	0.862	0.839	0.922	0.982	-1.8%	**$68,705**
Newbury Power	$42,155	N/A	N/A	1.384	0.967	1.175	1.034	3.4%	**$1,446**	N/A	N/A	0.724	1.057	0.891	0.949	-5.1%	**$2,135**
Tillsonburg Hydro	$1,302,458	0.943	1.299	1.169	1.380	1.198	1.054	5.4%	**$70,474**	1.042	0.767	0.866	0.748	0.856	0.912	-8.8%	**$114,482**
Wellington North Power	$847,699	1.107	1.132	1.188	1.251	1.169	1.029	2.9%	**$24,612**	0.870	0.862	0.835	0.809	0.844	0.900	-10.0%	**$84,973**
Midland Power Utility	$1,598,480	1.270	1.254	1.205	1.089	1.204	1.060	6.0%	**$96,072**	0.741	0.761	0.805	0.908	0.804	0.857	-14.3%	**$228,960**
Clinton Power	$354,117	1.131	1.340	N/A	1.341	1.271	1.118	11.8%	**$41,878**	0.860	0.736	N/A	0.762	0.786	0.838	-16.2%	**$57,535**
Brant County Power	$2,603,177	1.120	1.342	1.489	1.301	1.313	1.156	15.6%	**$405,733**	0.861	0.728	0.667	0.779	0.759	0.809	-19.1%	**$498,502**
West Coast Huron Energy	$1,148,015	1.244	1.396	1.373	1.722	1.434	1.262	26.2%	**$300,593**	0.799	0.721	0.746	0.607	0.718	0.766	-23.4%	**$268,982**
Grand Valley Energy	$171,219	1.529	1.468	1.585	1.832	1.604	1.411	41.1%	**$70,456**	0.659	0.695	0.655	0.578	0.647	0.689	-31.1%	**$53,218**
Dutton Hydro	$155,646	1.311	1.436	2.335	1.638	1.680	1.478	47.8%	**$74,477**	0.742	0.686	0.429	0.624	0.620	0.661	-33.9%	**$52,739**
GROUP AVERAGE						*1.136*								*0.938*			

[1]The output index was calculated using the elasticity weights drawn from our translog econometric cost model. The weights were 61.4% for customers, 23.9% for retail volume, and 14.7% for circuit KM of line.

[2]Companies are ranked by the productivity indexes.

Table 17, continued

Unit Cost and Productivity Indexes for Total OM&A Expenses [1, 2]

	Average OM&A Expenses	Unit Cost (Low Values suggest good cost management.)								Productivity (High values suggest good cost management.)							
		2002	2003	2004	2005	Average of Available Years	Average / Group Average [A]	Percentage Differences [A - 1]	Excess Cost Per Year	2002	2003	2004	2005	Average of Available Years	Average / Group Average [B]	Percentage Differences [B -1]	Excess Cost Per Year
Southwestern Midsize town LDCs																	
Chatham-Kent Hydro	$4,698,529	0.705	0.690	0.734	0.727	0.714	0.727	-27.3%	**-$1,281,658**	1.376	1.424	1.362	1.404	1.391	1.325	32.5%	**-$1,525,987**
Festival Hydro	$2,954,023	0.824	0.758	0.802	0.762	0.787	0.801	-19.9%	**-$587,022**	1.170	1.289	1.239	1.330	1.257	1.197	19.7%	**-$580,796**
Wasaga Distribution	$1,292,945	0.724	0.775	0.844	0.930	0.818	0.833	-16.7%	**-$215,311**	1.375	1.303	1.215	1.125	1.255	1.194	19.4%	**-$251,451**
Port Colborne (CNP)	$1,447,646	0.699	0.873	0.853	N/A	0.808	0.823	-17.7%	**-$255,948**	1.373	1.114	1.159	N/A	1.215	1.157	15.7%	**-$227,068**
Innisfil Hydro Distribution Systems	$2,465,220	0.861	0.884	0.975	0.977	0.924	0.941	-5.9%	**-$144,626**	1.157	1.141	1.053	1.071	1.106	1.053	5.3%	**-$129,486**
E.L.K. Energy	$1,679,279	0.935	1.029	0.879	N/A	0.948	0.965	-3.5%	**-$58,328**	1.098	1.011	1.204	N/A	1.104	1.051	5.1%	**-$86,078**
St. Thomas Energy	$2,549,829	0.813	0.868	0.941	1.009	0.908	0.924	-7.6%	**-$192,956**	1.196	1.135	1.065	1.013	1.102	1.050	5.0%	**-$126,308**
Bluewater Power Distribution	$7,072,941	0.944	1.001	0.925	0.942	0.953	0.971	-2.9%	**-$206,701**	1.044	0.998	1.098	1.100	1.060	1.009	0.9%	**-$65,046**
Woodstock Hydro Services	$2,746,297	0.919	0.943	1.021	1.034	0.979	0.997	-0.3%	**-$7,819**	1.069	1.056	0.992	0.999	1.029	0.980	-2.0%	**$56,113**
Orillia Power Distribution	$2,629,754	0.916	1.050	1.089	1.169	1.056	1.076	7.6%	**$198,599**	1.087	0.961	0.942	0.895	0.971	0.925	-7.5%	**$197,470**
Fort Erie (CNP)	$3,148,520	1.231	0.900	1.091	0.984	1.052	1.071	7.1%	**$223,379**	0.780	1.080	0.906	1.024	0.948	0.902	-9.8%	**$308,217**
Middlesex Power Distribution	$1,359,979	1.070	1.124	0.915	1.175	1.071	1.091	9.1%	**$123,509**	0.907	0.874	1.093	0.868	0.936	0.891	-10.9%	**$148,682**
Essex Powerlines	$5,561,232	1.141	1.025	1.133	1.247	1.137	1.158	15.8%	**$876,645**	0.900	1.015	0.934	0.865	0.928	0.884	-11.6%	**$645,797**
Haldimand County Hydro	$4,978,903	1.088	1.042	1.122	1.153	1.101	1.121	12.1%	**$604,083**	0.886	0.938	0.886	0.879	0.897	0.854	-14.6%	**$726,213**
Westario Power	$4,157,664	1.003	1.117	1.120	N/A	1.080	1.100	10.0%	**$416,244**	0.927	0.843	0.855	N/A	0.875	0.833	-16.7%	**$694,147**
Erie Thames Powerlines	$3,755,379	1.157	1.333	1.479	1.529	1.374	1.400	40.0%	**$1,500,691**	0.841	0.739	0.677	0.668	0.732	0.696	-30.4%	**$1,139,980**
GROUP AVERAGE						*0.982*								*1.050*			
Eastern LDCs																	
Hydro Hawkesbury	$656,384	0.596	0.630	0.570	0.687	0.621	0.636	-36.4%	**-$238,969**	1.566	1.500	1.684	1.426	1.544	1.443	44.3%	**-$290,935**
Hydro 2000	$170,263	0.578	0.678	0.659	1.230	0.786	0.805	-19.5%	**-$33,173**	1.614	1.394	1.459	0.797	1.316	1.230	23.0%	**-$39,171**
Lakefront Utilities	$1,307,426	0.711	0.678	0.808	0.971	0.792	0.811	-18.9%	**-$246,706**	1.358	1.443	1.232	1.045	1.270	1.186	18.6%	**-$243,810**
Peterborough Distribution	$5,103,207	0.835	0.781	0.814	0.831	0.815	0.835	-16.5%	**-$840,314**	1.132	1.226	1.196	1.195	1.187	1.109	10.9%	**-$557,701**
Cooperative Hydro Embrun	$302,333	0.993	1.079	0.974	1.151	1.049	1.075	7.5%	**$22,653**	1.023	0.954	1.074	0.927	0.995	0.929	-7.1%	**$21,318**
Renfrew Hydro	$719,735	0.967	0.947	0.949	0.906	0.942	0.965	-3.5%	**-$25,028**	0.944	0.977	0.992	1.059	0.993	0.928	-7.2%	**$51,852**
Kingston Electricity Distribution	$4,903,757	0.982	0.962	0.992	0.999	0.984	1.008	0.8%	**$37,745**	0.965	0.998	0.983	0.997	0.986	0.921	-7.9%	**$386,326**
Rideau St. Lawrence Distribution	$1,152,996	1.054	1.114	1.130	1.109	1.102	1.129	12.9%	**$148,327**	0.912	0.874	0.876	0.910	0.893	0.834	-16.6%	**$190,866**
Parry Sound Power	$856,835	1.037	1.138	1.302	1.365	1.210	1.240	24.0%	**$205,328**	0.945	0.873	0.775	0.755	0.837	0.782	-21.8%	**$186,491**
Eastern Ontario Power (CNP)	$1,100,647	N/A	1.632	1.216	1.534	1.461	1.496	49.6%	**$546,063**	N/A	0.588	0.803	0.649	0.680	0.635	-36.5%	**$401,229**
GROUP AVERAGE						*0.976*								*1.070*			
Large City Southern LDCs																	
Hydro One Brampton Networks	$13,370,715	0.629	0.609	0.544	0.587	0.592	0.704	-29.6%	**-$3,954,232**	1.618	1.694	1.930	1.823	1.766	1.368	36.8%	-$4,916,642
Hydro Ottawa	$37,805,068	0.852	0.698	0.634	0.625	0.702	0.834	-16.6%	**-$6,259,186**	1.193	1.475	1.652	1.709	1.507	1.167	16.7%	-$6,318,605
Powerstream	$33,730,504	0.644	0.733	0.780	0.818	0.744	0.884	-11.6%	**-$3,901,481**	1.581	1.408	1.345	1.308	1.411	1.092	9.2%	-$3,113,947
Horizon Utilities	$31,469,808	0.654	0.729	0.735	0.829	0.737	0.876	-12.4%	**-$3,905,639**	1.537	1.395	1.408	1.273	1.403	1.087	8.7%	-$2,724,183
London Hydro	$20,321,872	0.773	0.757	0.785	0.782	0.774	0.921	-7.9%	**-$1,613,649**	1.259	1.302	1.276	1.306	1.286	0.996	-0.4%	$91,428
Enersource Hydro Mississauga	$35,667,848	0.810	0.833	0.887	0.924	0.864	1.027	2.7%	**$955,497**	1.257	1.239	1.184	1.158	1.209	0.936	-6.4%	$2,270,048
Toronto Hydro-Electric System	$138,488,976	0.869	0.928	0.946	0.898	0.910	1.082	8.2%	**$11,377,729**	1.172	1.112	1.109	1.192	1.146	0.888	-11.2%	$15,556,149
Veridian Connections	$19,922,136	1.022	1.233	1.000	0.889	1.036	1.232	23.2%	**$4,618,033**	0.998	0.838	1.051	1.206	1.023	0.792	-20.8%	$4,135,764
ENWIN Powerlines	$20,080,970	1.265	1.239	1.228	1.112	1.211	1.440	44.0%	**$8,830,250**	0.812	0.840	0.861	0.970	0.871	0.674	-32.6%	$6,539,766
GROUP AVERAGE						*0.841*								*1.291*			
GTA towns LDCs																	
Kitchener-Wilmot Hydro	$9,351,437	0.594	0.610	0.608	0.619	0.608	0.699	-30.1%	**-$2,816,163**	1.673	1.653	1.685	1.688	1.674	1.383	38.3%	-$3,584,171
Barrie Hydro Distribution	$7,813,820	0.607	0.749	0.655	0.559	0.643	0.739	-26.1%	**-$2,040,601**	1.641	1.348	1.566	1.874	1.607	1.328	32.8%	-$2,559,109
Cambridge and North Dumfries Hydro	$7,104,172	0.711	0.698	0.760	0.706	0.719	0.826	-17.4%	**-$1,233,504**	1.398	1.443	1.348	1.481	1.417	1.171	17.1%	-$1,214,983
Burlington Hydro	$9,539,784	0.751	0.778	0.823	0.824	0.794	0.913	-8.7%	**-$828,373**	1.338	1.308	1.256	1.280	1.296	1.070	7.0%	-$671,762
Oakville Hydro Electricity Distribution	$9,223,560	0.784	0.880	0.827	0.798	0.822	0.945	-5.5%	**-$503,719**	1.291	1.165	1.261	1.331	1.262	1.042	4.2%	-$391,637
Guelph Hydro Electric Systems	$7,535,517	0.801	0.817	0.775	0.808	0.800	0.920	-8.0%	**-$600,090**	1.224	1.216	1.304	1.276	1.255	1.037	3.7%	-$277,380
Waterloo North Hydro	$8,171,374	0.863	0.846	0.848	0.801	0.839	0.965	-3.5%	**-$283,320**	1.152	1.190	1.208	1.305	1.214	1.003	0.3%	-$22,253
Milton Hydro Distribution	$3,572,770	0.958	0.889	0.849	0.870	0.891	1.025	2.5%	**$89,066**	1.049	1.145	1.219	1.213	1.156	0.955	-4.5%	$159,426
Whitby Hydro Electric	$6,584,501	0.949	1.025	0.918	0.950	0.960	1.104	10.4%	**$685,235**	1.076	1.009	1.145	1.129	1.090	0.900	-10.0%	$656,917
Welland Hydro-Electric System	$3,693,122	0.858	0.939	0.961	0.862	0.905	1.041	4.1%	**$150,503**	1.119	1.035	1.028	1.170	1.088	0.899	-10.1%	$373,639
Brantford Power	$6,180,431	0.841	0.923	1.001	0.982	0.937	1.078	7.8%	**$479,152**	1.146	1.058	0.992	1.031	1.057	0.873	-12.7%	$783,669
Newmarket Hydro	$5,165,882	0.916	1.327	0.926	0.866	1.009	1.160	16.0%	**$825,951**	1.100	0.769	1.121	1.223	1.053	0.870	-13.0%	$671,072
Niagara Falls Hydro	$7,093,752	1.026	1.035	1.048	1.106	1.054	1.212	21.2%	**$1,503,067**	0.935	0.939	0.944	0.911	0.932	0.770	-23.0%	$1,630,269
Centre Wellington Hydro	$1,420,028	1.295	1.214	1.151	1.114	1.194	1.373	37.3%	**$529,154**	0.758	0.818	0.878	0.925	0.845	0.698	-30.2%	$429,044
GROUP AVERAGE						*0.870*								*1.210*			

[1]The output index was calculated using the elasticity weights drawn from our translog econometric cost model. The weights were 61.4% for customers, 23.9% for retail volume, and 14.7% for circuit KM of line.
[2]Companies are ranked by the productivity indexes.
[3]Low values suggest good cost management
[4]High values suggest good cost management

Consumer Dividends (Con't)

<u>Dividends and the transition from cost of service regulation</u>

True that the theoretical rationale for consumer dividends is that IR creates stronger incentives compared with cost of service regulation

But theory never says consumer dividends should only be implemented one time (*i.e.* in first IR plan) and then be removed

Theory also consistent with the idea that consumer dividends should persist for many years after transition from cost of service regulation

>>Importance of long-term initiatives, and associated potential stream of long-term benefits

Pacific Economics Group, LLC
Economic and Litigation Consulting

Consumer Dividends (Con't)

<u>Dividends and the transition from cost of service regulation (Con't)</u>

Precedents also overwhelmingly support the use of consumer dividends more than a decade after switch from pure of service regulation

- Massachusetts
  - Boston Gas – 15 years
  - Bay State Gas – 15 years

    >> PEG supported both
- Germany – 15 years
- UK – Ofwat, more than 20 years

PEG not aware of <u>any</u> plans that have eliminated consumer dividend after expiration of first IR plan, although some companies have proposed this

Consumer Dividends (Con't)

<u>Not Appropriate to Benchmark OM&A Only</u>

Not true – short-run/restricted/conditional cost functions limited to OM&A are well established in econometric literature

Conceptually appropriate to benchmark OM&A costs <u>provided</u> there are proper controls for capital inputs

PEG's econometric benchmarking model in fact includes controls for two important dimensions of capital differences among distributors (capital quantity itself statistically insignificant when these variables are included)

- undergrounding
- system age

Consumer Dividends (Con't)

<u>OM&A Benchmarking can distort incentives</u>

Argued that OM&A benchmarking can distort incentives by giving companies incentives to reduce OM&A through "gold plating" or excessive investment

Not true with respect to benchmarking <u>past</u> performance, as PEG has done, as basis for IRM3 consumer dividends

May be a concern in future – but this is an argument for transitioning to more comprehensive benchmarking in the future, not ignoring benchmarking results now

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Consumer Dividends (Con't)

<u>Dividend values should be negative as well as positive</u>

Disagree – negative consumer dividends <u>will</u> generally create wrong incentives and the potential for inappropriate rewards under IR

- IR should mimic competition, where firms increase their profits only if they increase their efficiency compared to their rivals
- The *opposite* of this outcome can occur if there are negative consumer dividends

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Consumer Dividends (Con't)

<u>Example:</u>

- X factor = 0.8%
- Consumer Dividend Firm A = -0.3%
- Consumer Dividend all other firms = 0

  >>All else equal, real price reductions of 0.5% for Firm A and 0.8% for all other firms
- In Year 1, Firm A decreases its unit cost by 0.6%, all other firms in industry decrease their unit cost by 0.8%
- Profits of Firm A increase, profits of all other firms are unchanged

  >> Profits increase only for the firm that has under-performed compared to industry

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Consumer Dividends (Con't)

Also disagree that negative consumer dividends should be established to reflect distributor diversity

- no empirical basis for such diversity factors
- there are other, better ways to account for distributor diversity

Staff's IRM3 proposal has several features that accommodate diversity

- rebased rates
- capital modules
- earnings sharing mechanism
- off-ramp

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Consumer Dividends (Con't)

PEG has nevertheless updated its consumer dividend recommendation to make it less complex and more consistent with Ontario precedents

Updated recommendation is three consumer dividends

Group I:	Significantly superior <u>and</u> in top quartile on productivity index ranking
Group III:	Statistically inferior <u>and</u> in bottom quartile on productivity index ranking
Group II:	All others

Generally supported by Professor Yatchew's analysis submitted on PEG's comparative cost report

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Table 1: Classification Frequencies				
	Total Costs			
OM&A Costs	Bottom Quartile	Third Quartile	Second Quartile	Top Quartile
Top Quartile			5	11
Second Quartile		7	5	4
Third Quartile	5	5	5	1
Bottom Quartile	10	4	1	

Consumer Dividends (Con't)

PEG recommends the following consumer dividends

Group	Consumer Dividend
I	0
II	0.25%
III	0.5%

These values correspond more closely to Ontario precedents

- Most companies will be in Group II and have a consumer dividend equal to the value approved for all distributors in IRM1
- Highest approved dividend in IRM3 is average dividend level in approved North American plans, but maximum dividend approved to date in Ontario (Union Gas PBR)

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K Factor

The companies and their experts have recommended that a K factor be added to IRM3

However, these proposals do not adequately address the difficulty of forecasting capital expenditures, which is the most important issue that must be addressed before such a factor can be added

>>discussed extensively in Working Group

K Factor (Con’t)

With K factor type mechanisms, companies have inherent incentives to:

- forecast high capital expenditures
- underspend and pocket the “efficiency” savings while the IR plan is in effect
- forecast high capital expenditures at the outset of the next IR plan

Extensive experience in the UK, led to the adoption of various “information quality initiatives” to elicit accurate forecasts and ex-post efficient behavior

Mechanisms still being refined in the UK

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K Factor (Con’t)

Complexities of designing IQIs led Working Group to abandon this option and to focus on capital module instead

Unrealistic to think these complexities can be resolved in time remaining for IRM3

Capital module more administratively efficient and workable approach that is less prone to forecast “gaming” concerns

K Factor (Concl)

K factor also raises other issues

- All parties reject the “hybrid” IR approach in principle, but regulating capex and OM&A separately is effectively a hybrid
- TFP trends no longer appropriate in hybrid regulation; if indexing is just applied to OM&A, need to use OM&A PFP growth instead
- Must ensure that there is no “double counting” of allowed price changes by having two separate rate adjustment mechanisms

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Recommendations

- Single industry TFP trend based on US TFP data trend = 0.88%
- No inflation differential, but further research on industry IPI
- Three consumer dividends between 0 and 0.5% based on Ontario benchmarking
- Average X factor still probably about 1.15%
  - >> less than X for all distributors in IRM1
  - >> somewhat greater than current X=1%, although X factor will decline for significantly superior cost performers
- Capital module instead of K-factor

Future IR applications can put more weight on:

- Index-based Ontario TFP trends
- Total cost benchmarking for Ontario industry