Incentive Regulation for Ontario Power Distribution

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Introduction

The Ontario Energy Board ("OEB") is developing forms of incentive regulation for energy distribution today

- Power Distribution
  - Second Generation
  - Third Generation
- Gas Distribution

Pacific Economics Group ("PEG") is honored to be Board's advisor on incentive regulation

Introduction

Goals of Presentation

- Help stakeholders develop common knowledge base on incentive regulation principles and precedents
- Highlight relevant plan design issues in power distribution applications

Plan of Presentation

Introduction to Incentive Regulation

Incentive Plan Design

- **Plan Term**
- **Rate Adjustment Mechanisms**
- **Plan Update Provisions**
- **Service Quality**
- **Marketing Flexibility**
- **Incentive Power**

Conclusions

II. Introduction to PBR

Critique of Traditional Regulation

Costly for regulators to make informed & fair decisions on utility rates & quality standards

Cost of traditional cost of service regulation (COSR) depends on

Number of jurisdictional utilities

Nature of business: some activities are especially difficult to regulate

- Energy supply
- Affiliate relations
- Complex rate and service offerings

Critique (cont'd)

Short cuts taken to contain regulatory cost…

Limit scope of prudence reviews

Discourage practices that complicate regulation

can have deleterious consequences

Weakened performance incentives

Reduced operating flexibility

- Energy procurement
- Rate and service offerings

Critique (cont'd)

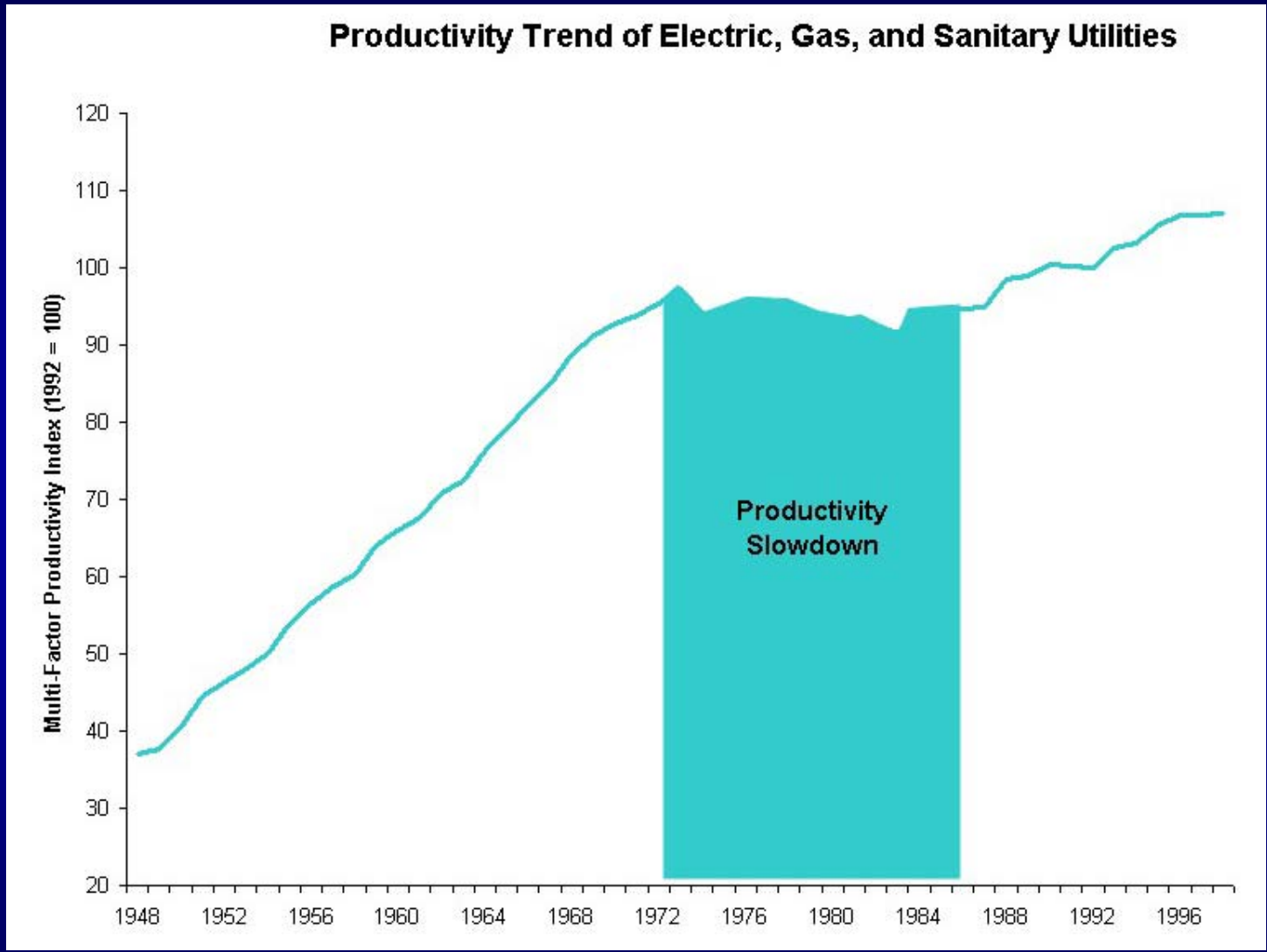
Inadequacies of COSR were highlighted by U.S. experience

A "perfect storm" of unfavorable operating conditions 1974-85

- Rapid input price inflation
- Energy price volatility
- Slowing demand growth

led to rapid unit cost growth & frequent rate cases. Results:

- Plummeting productivity growth
- Unprecedented cost disallowances
- Energy industry restructuring


Productivity Trend of Electric, Gas, and Sanitary Utilities
Multi-Factor Productivity Index (1992 = 100)
120
110
100
90
80
70
60
50
40
30
20
1948
1952
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
Productivity
Slowdown

What is Incentive Regulation?

General approach to regulation developed in 1980s to address special regulatory challenges.

Goes by many names, including Performance-Based Regulation (PBR)
Alternative Regulation (Altreg)

Basic idea: decouple a utility's rates from its own unit cost

>>> "Externalization" of regulatory system

Two basic ways to achieve externalization:
- Rate case moratoria
- Partial cost true-ups

What is Incentive Regulation? (cont'd)

Active ingredients for just & reasonable externalization include…

1. External information on utility operations & relevant business conditions

2. Research on how external business conditions affect cost

    - Input price and productivity indexes
    - Econometric cost modeling

3. Research on how utilities respond to regulatory systems

What is Incentive Regulation? (cont'd)

Works best where

Stronger performance incentives can trigger performance improvements

Relationship of business conditions to cost is understandable

- Copious, relevant, high quality data are available
- Relationship of business conditions to cost is comparatively simple

Altreg Advantages

Stronger performance incentives

- Cost Containment
- Marketing

Increased operating flexibility

>>> Better operating performance

>>> Accelerated human capital investment

More efficient regulation

Altreg Disadvantages

Risk-return imbalance

Hard to externalize rates without increasing risk

Business Risk	Prices less sensitive to business conditions
Regulatory Risk	Plan terms may be chosen arbitrarily Policymakers may not stick with deal

Higher risk >>> higher cost of funds that erodes Altreg benefits

>>> Innovations in regulation that reduce risk without weakening incentives are valuable

Altreg on Balance

Altreg most widely used where

Altreg advantages of Altreg are greatest

- Large amount of high quality data available
- Easy to model utility activity

Advantages of COSR are “leastest”

- Rising unit cost environment
- Intractable regulatory issues are prevalent
- Numerous jurisdictional utilities

Incentive Regulation Precedents

Altreg standard for North American telcos & railroads, all utilities overseas

Altreg widely used by North American energy utilities

e.g. Formal Altreg plans

New England	CT, MA, ME, RI
Mid-Atlantic	NY, NJ, MD, PA
Southeast	AL, GA, FL, KY, LA, MS, NC, TN
North Central	IA, IL, MI, MO, MN, ND, SD, WI
West	CA, CO, ID, OR, WA
Canada	ALTA, BC, ON, PQ, NEB

Altreg Plan Design

Plan Term

PBR plans typically last 5 years

Some recent plans have 10 year terms

National Grid (MA, NY)	Power distribution
Boston Gas	Gas distribution
Berkshire Gas	Gas Distribution
MidAmerican Energy	Bundled power service

Rate adjustment mechanisms key issue in plan design

- Rate caps
- Revenue caps

Rate Adjustment Mechanisms
Rate Indexing

The Basic Idea

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

growth in Rates < growth in *PCI*

PCI growth determined by formula

growth in *PCI* = *P* - *X* + *Z*

P = Growth in external inflation measure

X = X-factor reflects productivity growth

Rate Indexing

The Basic Idea (cont'd)

Z = Z-factor adjusts PCI growth for

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

The Basic Idea (cont'd)

4 established approaches to PCI design

1. North American Approach
2. British Approach
3. X Factor Nomination
4. Peer-Price Approach

North American Approach

In North America, index design commonly based on index research

Logic of Economic Indexes

If an industry earns competitive return,

$$\text{trend Prices}^{\text{Industry}} = \text{trend Unit Cost}^{\text{Industry}}$$

>>> PCI calibrated to track *industry* unit cost trend

$$\text{trend Unit Cost} = \text{trend Input Prices} - \text{trend TFP}$$

TFP = Total Factor Productivity

North American Approach (cont'd)

Key issues in North American price cap proceedings

(1) What is TFP trend?

(2) What is input price trend?

TFP

What is TFP?

trend in TFP = trend in Output - trend in Input

= trend Input Prices – trend Unit Cost

Fluctuates over time, long-term trend positive

Recent TFP trend of U.S. economy: 1.3%

Sources of TFP growth: Technological change
Scale Economies
Scope Economies
Change in Other Business Conditions
Reduced "X-Inefficiency"

TFP (cont'd)

How is TFP measured?

Conventionally measured using TFP index

Alternative samples available

- Subject utility
- Ontario utilities
- Canadian utilities
- U.S. utilities
- Multiple sources

TFP (cont'd)

TFP trends used in PCI design can be customized to reflect operating conditions of individual utilities using econometric research.

e.g. Given a cost function like

$$\text{Cost} = a_0 + a_1 P_{\text{labor}} + a_2 \text{Customers} + a_3 \text{Undergrounding}$$

parameters can be estimated econometrically. TFP trend can be "predicted" for utilities and reflect local business conditions:

- Operating scale
- Expected output growth
- Expected change in undergrounding

TFP Measurement Controversies

Gray areas in science invite gaming, dueling expert witnesses

e.g. 1: Output

Alternative output quantity measures available

Peak Demand? Volume? Customers?

Appropriate weights depend on application

Price Cap	*Revenue* impact weightings
Revenue Cap	*Cost* impact weightings

TFP Measurement Controversies (cont'd)

e.g. 2 Capital cost & quantity

TFP indexing requires that

Capital Cost = Capital price x Capital Quantity

Results depend on how capital cost is measured

North American Approach to Indexing (cont'd)

TFP Precedents

Regulators in several jurisdictions have weighed evidence on industry TFP trends and made judgments

Averages

- Power distribution 1.06
- All energy distribution 1.01%

Most recent PEG estimate: 0.95%, Northeast U.S.

Approved trends somewhat higher in Australia & New Zealand, but reflect recent privatizations there

Table 1

Industry	Company	Term	Jurisdiction	Acknowledged Productivity Trend	Inflation Measure	Stretch Factor	X-Factor	Comments
Gas distribution	Boston Gas (I)	1997-2003	Massachusetts	0.40%	GDPPI	0.50%	0.50%	
Gas distribution	Boston Gas (II)	2004- 2013	Massachusetts	0.58%	GDPPI	0.30%	0.41%	
Gas distribution	Berkshire Gas	2002-2011	Massachusetts	0.40%	GDPPI	1.0%	1.0%	Adopted the productivity study used by Boston Gas I
Gas distribution	Consumers Gas	2000-2002	Ontario	0.63%	CPI	0.50%	1.10%	O&M Productivity
Gas distribution	Union Gas	2001-2003	Ontario	0.9%	GDPPI	0.5%	2.5%	
Gas distribution	San Diego Gas and Electric	1999-2002	California	0.68%	Industry specific	0.55% (Average)	1.23% (Average)	
Gas distribution	Southern California Gas	1997-2002	California	0.50%	Industry specific	0.80% (Average)	2.30% (Average)	Special 1% factor added to X to reflect declining rate base
Gas distribution	Bay State Gas	2006-2015	Massachusetts	0.58%	GDPPI	0.4%	0.51%	Adopted Boston Gas II
Bundled power service	Pacificorp	1994-1996	California	1.4%	Industry specific	NA	1.4%	Company specific productivity
Power distribution	San Diego Gas and Electric	1999-2002	California	0.92%	Industry specific	0.55% (Average)	1.47% (Average)	
Power distribution	Southern California Edison	1997-2002	California	NA	CPI	0.58% (Average)	1.48% (Average)	0.90% productivity trend estimated by Edison and Commission staff but not formally acknowledged by CPUC
Power distribution	All Ontario distributors	2000-2003	Ontario	0.86%	Industry specific	0.25%	1.5%	Productivity trend referenced is the 10 year average growth rate X factor is based on 5 and 10 year weighted average
Power distribution	Nstar	2006-2012	Massachusetts	NA	GDPPI	NA	0.63% (average)	
Bundled power service	Central Maine Power (I)	1995-1999	Maine	NA	GDPPI	NA	0.9% (average)	
Power distribution	Central Maine Power (II)	2001-2007	Maine	NA	GDPPI	NA	2.57% (average)	
All utilities	**Sample Average**			**0.70%**			**1.21%**	
All industry specific	**Sample Average**						**1.58%**	
All macroeconomic	**Sample Average**						**1.01%**	

Stretch Factors

Stretch factors often added to X factors of rate escalation indexes

Higher X >>>> More guaranteed customer benefits

Impact on performance incentives more controversial

Precedents:

0.50% “consumer productivity dividend” for AT&T

0.54 average, energy utilities

Stretch factors generally higher for telecom utilities

North American Approach to Indexing (cont'd)

Inflation Measures

Two kinds of inflation measures in widespread use

1. Macroeconomic (e.g. CPI, GDP-IPI)

2. Industry-Specific

e.g. $P = 0.25 \times \text{growth in } P^{\text{Labor}} + 0.25 \times \text{growth in } P^{\text{Other O\&M}} + 0.50 \times \text{growth in } P^{\text{Capital}}$

Industry cost shares are weights

Industry-Specific Inflation Measures

Case Study: Ontario Power Dx

Input Category	Approved Subindex
Labor	Ontario Average Weekly Earnings
Other O&M	Industrial Producer Price Index
Capital	Custom Index based on …
	Canadian construction cost index Bank of Canada long bond yields

Controversy encountered in capital subindex specification

Industry-Specific Inflation Measures (cont'd)

Capital Price Indexes

Capital price index is key design issue. In theory

Capital Cost = Price x Quantity

Four capital cost components are potentially relevant

- Opportunity Cost
- Depreciation
- Taxes
- Capital Gains

Key capital cost "drivers": Construction Cost
Cost of funds

Macroeconomic Inflation Measures

Most widely used macroeconomic inflation measure is the gross domestic product implicit price index ("GDP-IPI").

Covers inflation in prices of "final" goods & services: consumer products, gov't, investments, exports

In Canada, this inflation measure has disadvantage of sensitivity to commodity price inflation given importance of oil, gas, & other commodities in Canadian exports.

Alternatives to "conventional" GDP-IPI can finesse this situation:

GDP-IPI	Canada	Final Domestic Demand
GDP-IPI	Ontario	

Macroeconomic Inflation Measures (cont'd)

When PCI has *macroeconomic* inflation measure, X factor calibration involves two terms:

Productivity Differential ($TFP^{industry}$ - $TFP^{economy}$)

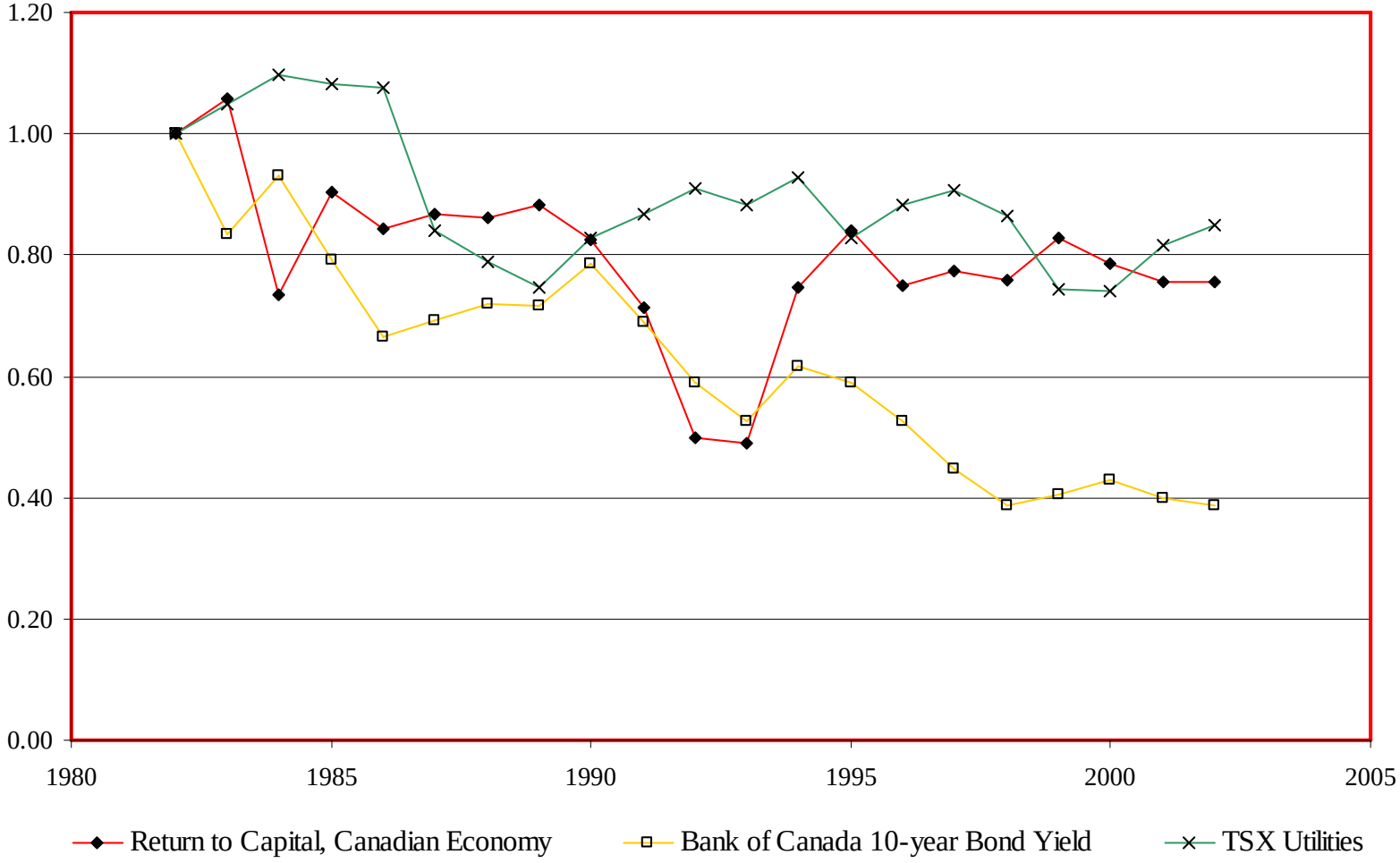
Input Price Differential ($Prices^{economy}$ - $Prices^{industry}$)

Input price differential controversial in some proceedings

Central Maine Power	Power Dx	ME
Union Gas	Gas Dx	ON

Reasons: Capital intensive industry
Falling trend in long bond yields

Alternative Return to Capital Measures, Growth Trends 1982-2002



X Factor Precedents

X factors approved in proceedings where index research considered reflect evidence on productivity, input price inflation, & stretch factor

Table 1 summarizes relevant precedents:

All escalation indexes		1.21%
Inflation measure = industry specific		1.58%
Inflation measure = macroeconomic		1.01%
Inflation measure = macroeconomic	Electric	1.56

Most recent X for power distribution: 0.63%

X Factor Precedents (cont'd)

Data on utility rate trends contain *implicit* X factors

$$X^{implicit} = \text{trend GDPIPI} - \text{trend Rates}$$

e.g.

Evidence on rate trends for U.S. gas distributors suggests "macroeconomic" X factor of 1.1% 1995-2005

>>> Precedents suggest a "macroeconomic" X factor for 2nd Generation power distribution Altreg in the [0.63% - 1.56%] range

IMPLICIT X FACTOR IN GAS DISTRIBUTION RATES, 1991-2005

Year	PPI Natural Gas Distribution - Transportation Only		GDP-PI		Implied X Factor
	Level	Growth Rate	Level	Growth Rate	
1991	96.8		84.5		
1992	99.5	2.8%	86.4	2.3%	
1993	101.5	2.0%	88.4	2.3%	
1994	101.2	-0.3%	90.3	2.1%	
1995	106.9	5.5%	92.1	2.0%	
1996	105.7	-1.1%	93.9	1.9%	
1997	109.4	3.4%	95.4	1.6%	
1998	103.6	-5.4%	96.5	1.1%	
1999	102.3	-1.3%	97.9	1.4%	
2000	103.9	1.6%	100.0	2.2%	
2001	103.4	-0.5%	102.4	2.4%	
2002	105.5	2.0%	104.2	1.7%	
2003	108.2	2.5%	106.3	2.0%	
2004	113.3	4.6%	109.1	2.6%	
2005	116.3	2.6%	112.2	2.8%	
Formula		**[B]**		**[A]**	**[A] - [B]**
Average 91-05		**1.3%**		**2.0%**	**0.7%**
Average 95-05		**0.8%**		**2.0%**	**1.1%**
Average 00-05		**2.3%**		**2.3%**	**0.0%**
Average 95-00		**-0.6%**		**1.6%**	**2.2%**

Source, PPI Natural Gas Distribution Transportation Only: Bureau of Labor Statistics; http://www.bls.gov

Source, GDP-PI: Bureau of Economic Analysis; http://www.bea.gov

Note: Assumes GDPPI - X Index Formula

British Approach to Rate Index Design

Common approach to index design in Britain & Australia

- Forecast cost over *next five years*
- Focus on "controllable costs": opex and capex
- Recovery of older capital cost assured
- Forecast other key variables (*e.g.* CPI, delivery volumes)
- Choose X & initial rates so that…
  - expected revenues = expected cost

X Factor Nomination Approach

Utility offered "menu" of alternative X factors and other plan provisions (*e.g.* earnings sharing, plan terms)

Its choice reveals productivity growth expectations

e.g.	Curtain #1	growth PCI = CPI – 2% no earnings sharing
	Curtain #2	growth PCI = CPI – 1% earnings sharing

Peer Price Index Approach

Basic Idea

PCI = Index of rates charged by of other utilities

Precedents

Northern Indiana PS	Bundled Service	IN
Illinois Power	Bundled Service	IL
National Grid	Power Distribution	MA

Peer-Price Pros & Cons

Pro: Becoming feasible in North America as retail competition matures

Reflects regional input price and productivity trends

No controversies over input price and TFP measurement

Con: U.S. experience has limited relevance to Canada

Little power distribution data outside Ontario

>>> Canadian regulators should share data on rate trends for gas & electric power distribution

Revenue Caps

Basic Idea

Cap *revenue requirement*, not prices

Balancing account ensures that Revenue = Requirement

Revenue Cap Precedents

Power Transmission

All utilities	Tx	Britain
All utilities	Tx	Australia

Other Electric

Post test year (attrition)	All utilities	USA - CA
San Diego Gas & Electric	Bundled Power	USA - CA
PacifiCorp	Power Dx	USA - OR
BC Gas	Gas Dx	Canada - BC
West Kootenay Power	Bundled Power	Canada - BC
All power distributors	Dx	Australia - NSW

Revenue Cap Escalation

Revenue caps usually involve escalation provisions since

Revenue depends on *cost*, not *unit* cost

Two escalation mechanisms in widespread use

- Comprehensive indexing
- Separate treatment of O&M, capital

Comprehensive Indexing

Revenue cap index (RCI) provides extra compensation for output growth

$$\text{growth RCI} = P - X + Y +/- Z$$

$$Y = \text{growth Output Quantity}$$

Simplifications common:

e.g. Y and X may be consolidated
If X = Y, formula simplifies to growth RCI = P +/- Z
If P = X, formula simplifies to growth RCI = Y +/- Z

Revenue Caps (cont'd)

Separate Treatment of O&M, Capital

Some revenue cap plans have separate treatment of O&M, capital

e.g.

O&M expenses:	Indexing
Capital spending	Assume capex = recent historical average

Precedents: CA: post test year (attrition) mechanisms
ALTA: NOVA Gas Transmission
BC: BC Gas, West Kootenay Power

Revenue Cap Pros & Cons

Pro

- Strong incentives for cost containment
- Less demand risk, may reduce cost of funds
- Dovetails with conservation
- Alternative to frequent rate cases for companies with declining volume per customer (*e.g.* gas distributors)

Con

- Greater price volatility
- Conservation achievable by other means
- Weaker incentives for service quality?

Plan Update Provisions

Plan update provisions can affect

- Long term performance incentives
- Timing of maintenance & capex

Two established innovations to traditional rate case process

1. Statistical Benchmarking

2. Efficiency Carryover Mechanism

Statistical Benchmarking

Cost compared to benchmark based on statistical research

Share difference between actual cost & benchmark

Common applications:

Base Rate Revenue	UK, Sweden, Norway, Netherlands Enbridge Gas Distribution
Energy (*e.g.* gas) Procurement	

Benchmarking may apply to historic costs, proposed costs

Efficiency Carryover Mechanisms

Allow utilities to keep a share of long term performance gains when plans are updated

Example 1: Utility keeps its share of earnings surplus (*e.g.* AmerenUE)

Example 2: New rates based 80% on rate case, 20% on rates yielded by extension of expiring PBR mechanism

Precedents

Numerous companies	Power Distribution	ANZ, Britain
National Grid USA	Power Distribution	MA
AmerenUE	Bundled Power Service	MO

Benefit Sharing Mechanisms

Benefit sharing mechanisms are a controversial issue in PBR plan design

Several basic ways to share plan benefits

- Earnings sharing
- Sweeten Rate/Revenue Cap Trajectory (*e.g.* Stretch Factor)
- Rate Cases

Benefit Sharing Mechanisms (cont'd)

Key issues in mechanism selection

- Performance Incentives
- Risk
- Regulatory Cost

Earnings Sharing Pro:

Transparent alignment of shareholder and customer interests

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

Benefits shared *as realized*

Customers benefit *earlier*

Reduces risk

Discourages extremely high or low earnings

Earnings Sharing Con:

Weakens performance incentives *if no plan extension*

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

Heightened concerns about cross subsidies makes earnings sharing unpopular where this is key issue (*e.g.* telecom)

Earnings calculations can be controversial

Customers disappointed when earnings not in sharing range

>>> Many utilities strongly oppose earnings sharing

Marketing Flexibility

Need for Flexibility

Rates inconsistent with known cost drivers

e.g. power transmission & distribution

Desire to serve markets with diverse customer needs & competitive pressures from a *common set of assets*

- Power generation
- Telecom
- Railroads
- Oil Pipelines

Automatic Rate Redesign

Utilities can make *gradual* rate adjustments

growth in *API* < growth in PCI

API = Actual Price Index

e.g. growth API = .2 x growth customer charges +
.2 x growth demand charges +
.6 x growth volumetric charges

growth customer charges < growth PCI + 3%

Optional Tariffs and Services

Optional rates for traditional utility services

New utility services

Competitive Market Services

Special Service Bundles

Service Quality

Customer welfare depends on service quality (SQ), not just price

Insuring proper quality levels is vital responsibility

SQ provisions common in PBR plans

- Quality monitoring
- Award/Penalty mechanism

Quality provisions rarely receive attention paid to *price* provisions of PBR plans

SQ Recommendations

Continued quality monitoring will do for 2nd Generation incentive regulation

However, SQ award/penalty mechanisms deserve careful attention in subsequent Altreg plans

Consideration should be paid to

- Optimal quality standards
- Awards as well as penalties
- Inherent fluctuation in quality levels

Incentive Power

General performance incentives depend on PBR plan details

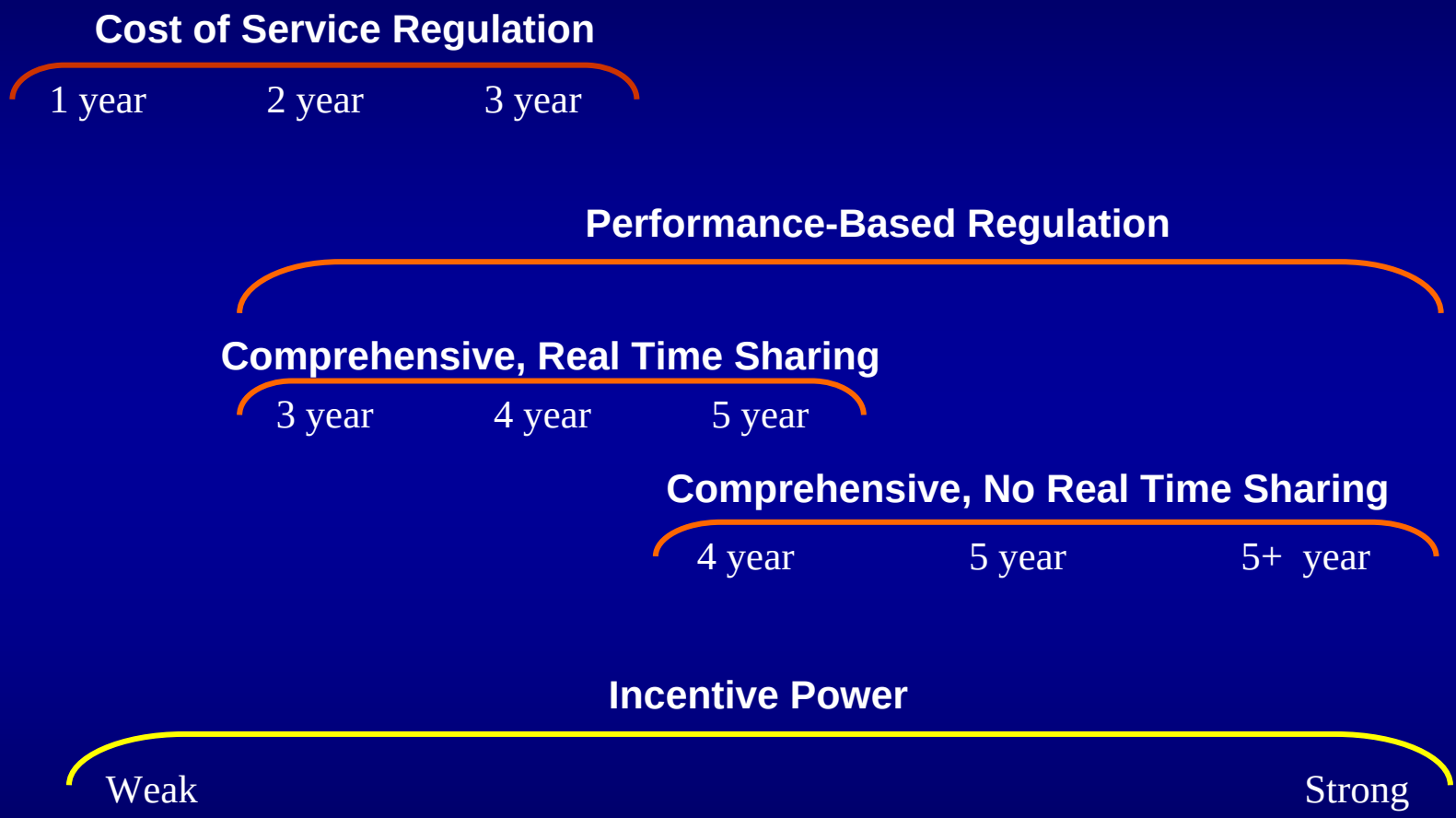
Not always stronger than traditional COSR due to

- Short plan term
- Real-time sharing (*e.g.* earnings sharing)

Meanwhile, COSR can be fine tuned to improve effectiveness

- Increase regulatory lag
- Strengthen prudence review process

The Incentive Spectrum



Incentive Power (cont'd)

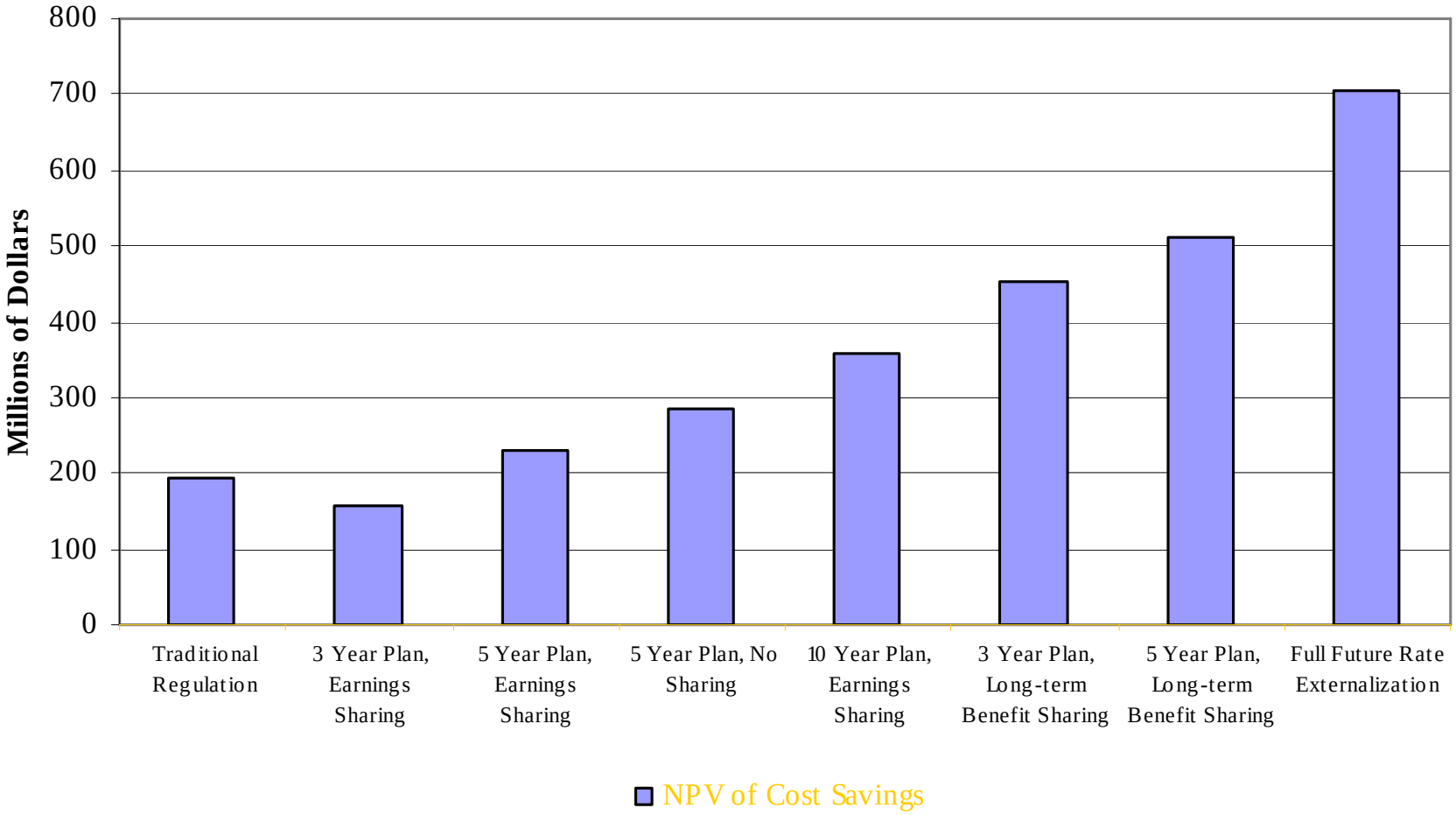
PEG has ongoing program of incentive power research

Goal: quantify key consequences of alternative regulatory systems

- Cost savings
- Customer benefits
- Earnings

OEB has suscribed to this research program

Illustrative Results from Incentive Power Model



Conclusions

The OEB has good reason to use North American style indexing given its jurisdiction over numerous, similarly-situated utilities.

2nd -generation incentive regulation can sensibly be based on GDP-IPI & North American X factor precedents

Precedential X factor range: [0.60 – 1.6]

Conclusions

The following issues merit close attention in the *further* evolution of Ontario incentive regulation

- Best rate escalation method
- Plan term
- Plan update provisions
- Accommodation of mergers
- Balancing incentives for cost containment, quality
- Best balance of performance incentives & operating risk

Material progress in addressing these challenges can make the OEB a world leader in incentive regulation