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Experience with TFP methods in regulation of North American electric utilities

Presentation to
Australian Energy Market Commission

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Key messages

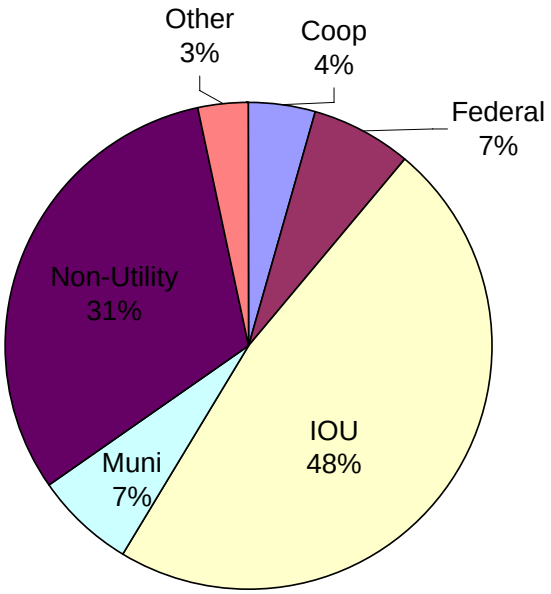
- Use of TFP is the exception, rather than the norm, for North America
- Where TFP is used, no agreed upon model exists for either analysis or for the regulatory framework
- Hybrid models incorporating earnings sharing mechanisms (ESMs) often preferred
- Regulators struggle with choice of relevant geographical regions and historical time periods for comparative analysis
- On the wires side of the business, North American regulators have tended to be followers rather than leaders, with limited awareness of trends overseas

Plan of presentation

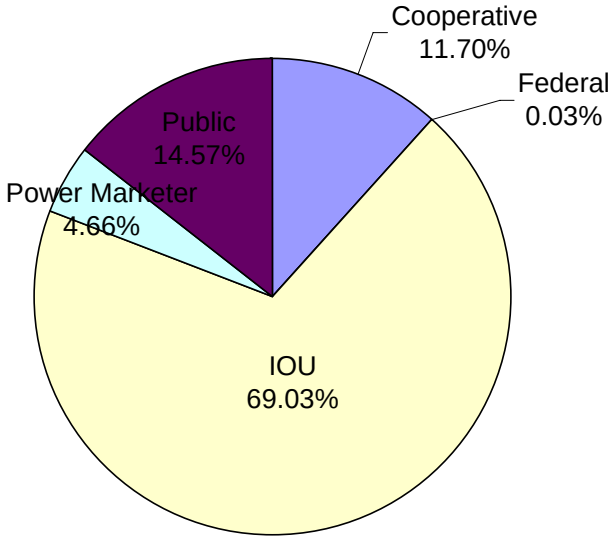
- **Overview of North America**
- California
- Canada
- New England

There is significant variety in utility ownership structures in the US

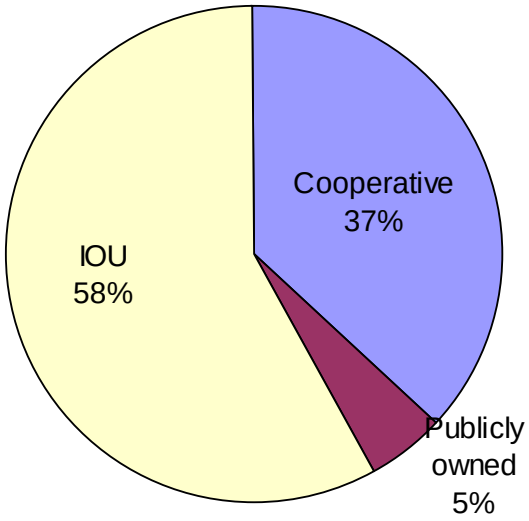
Capacity by ownership (2005)



Number of consumers served (2005)

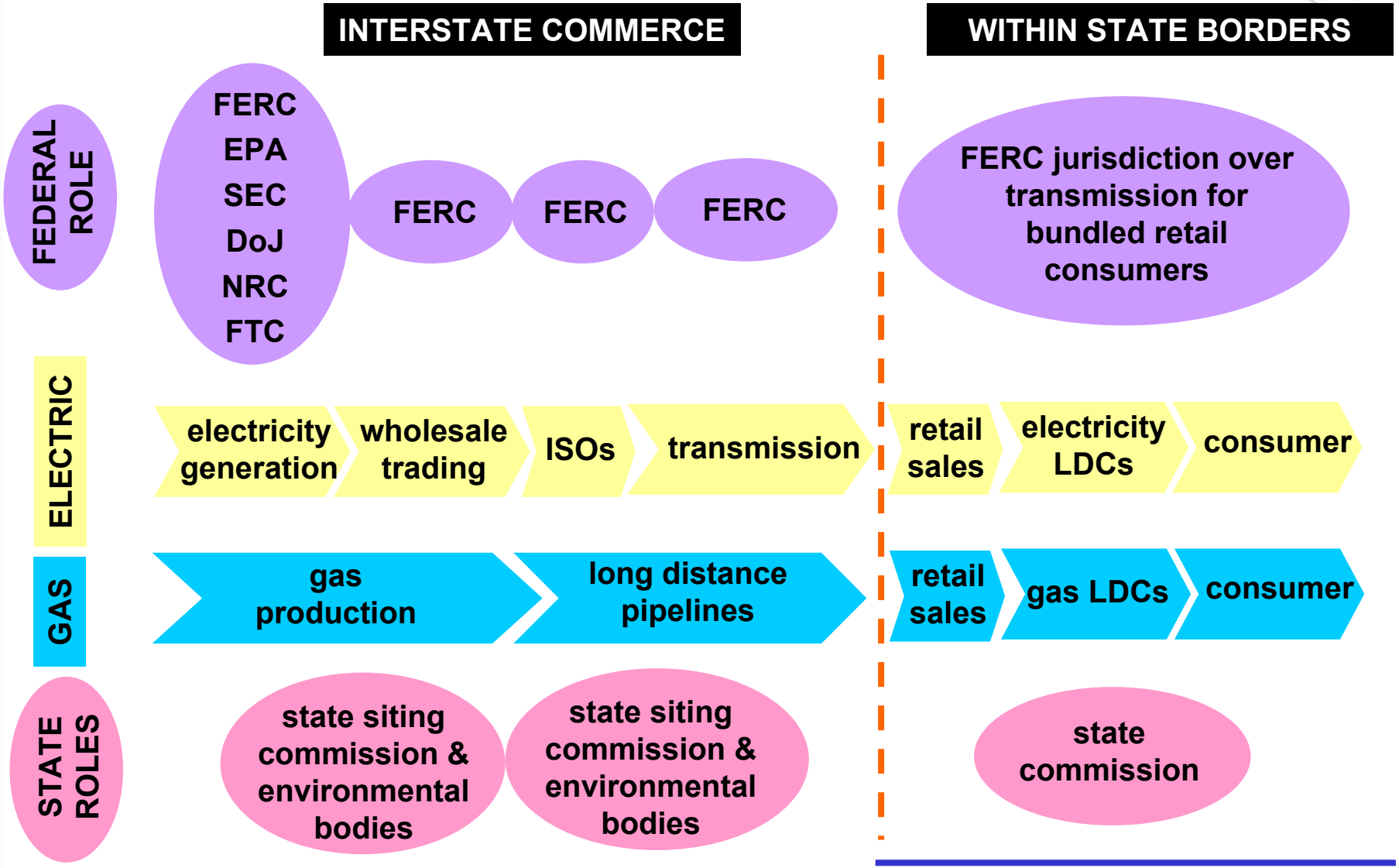


Total wires assets (above 230 kV) owned (2006)



Source: Energy Velocity

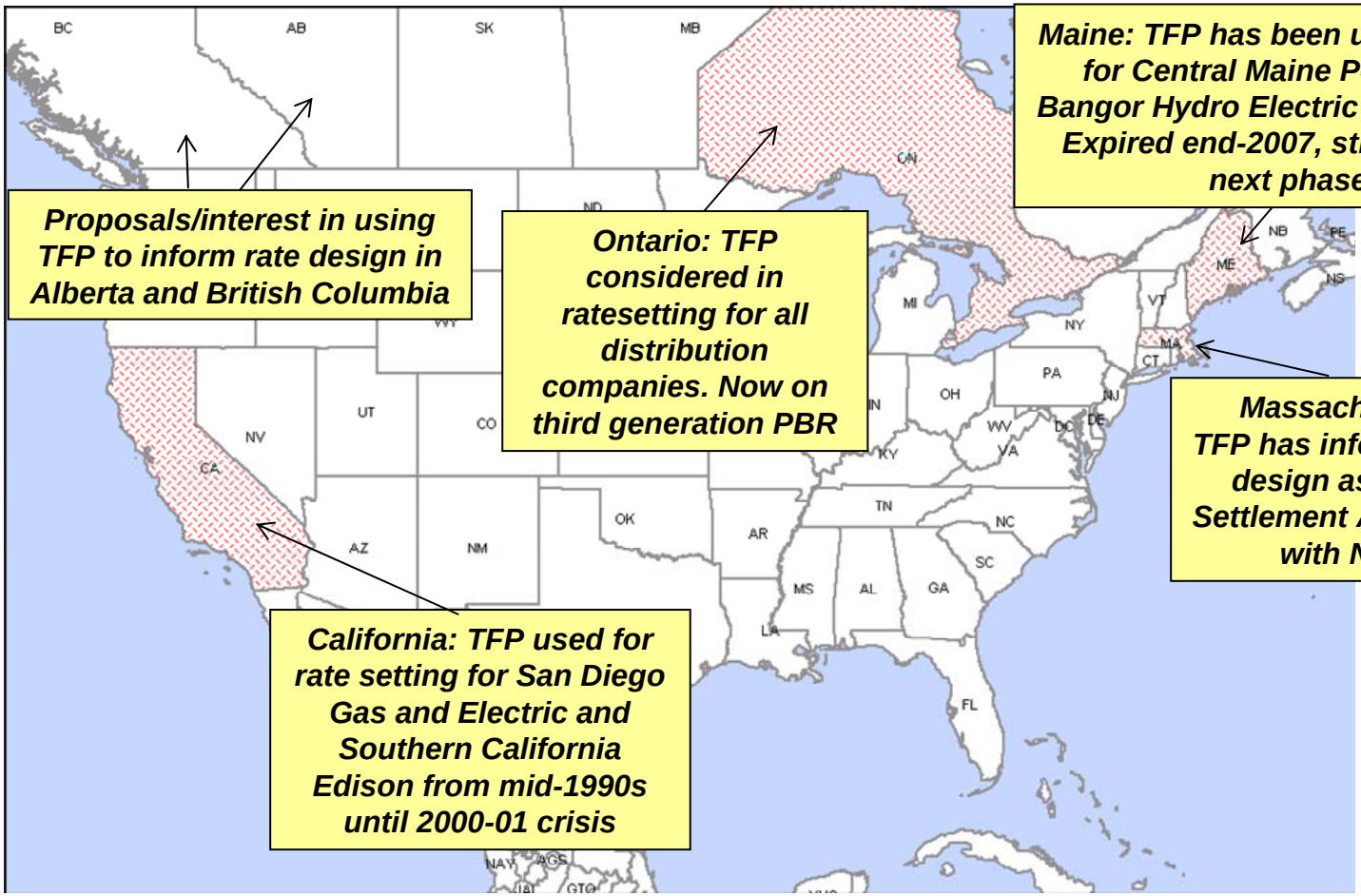
Overlapping regulatory jurisdictions hinder market evolution



Wires business has not been major focus of North American regulators

- US regulators in particular lack “clean slate”
  - unable to force unbundling
  - different forms of organization
  - mix of state and federal jurisdiction
- Focus largely on whether or not to move to competitive wholesale markets
  - US now seeing “return to ratebase”
  - concern about generation-driven price spikes to end users
  - retail markets and procurement take up much of regulators’ time in unbundled states
  - renewables programs also absorb regulatory bandwidth
- Financial stability also key regulatory concern
  - “ring-fencing” of finances
  - consideration of mergers

Use of TFP in electric distribution ratesetting relatively rare in North America



Maine: TFP has been used in rates for Central Maine Power and Bangor Hydro Electric Companies. Expired end-2007, still awaiting next phase

Proposals/interest in using TFP to inform rate design in Alberta and British Columbia

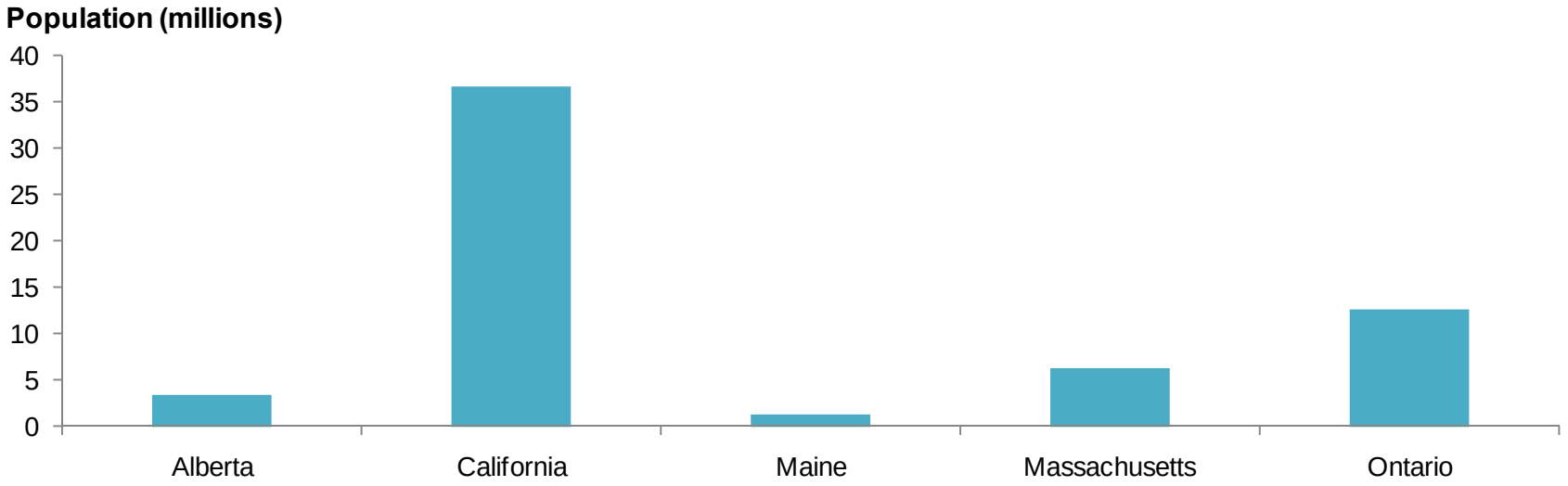
Ontario: TFP considered in ratesetting for all distribution companies. Now on third generation PBR

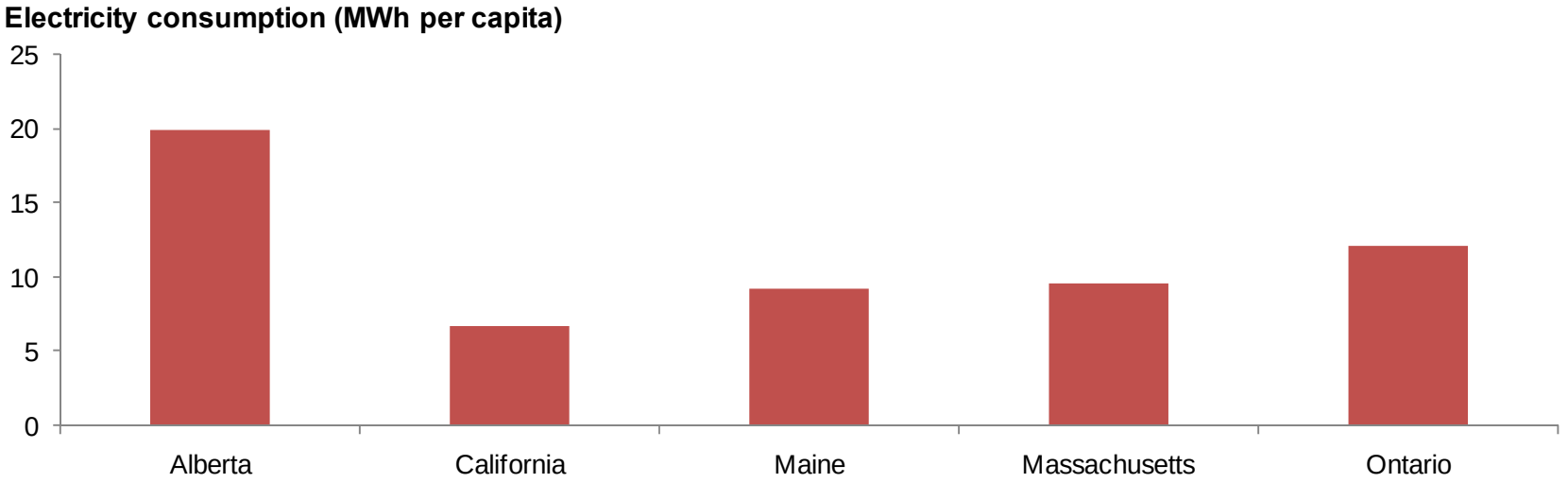
Massachusetts: TFP has informed rate design as part of Settlement Agreement with Nstar

California: TFP used for rate setting for San Diego Gas and Electric and Southern California Edison from mid-1990s until 2000-01 crisis

TFP has been used in a small number of gas distribution cases, including in Ontario, Massachusetts (Boston Gas, Berkshire Gas and Bay State Gas), and in California (SDGE and SCE gas distribution)

Jurisdictions using TFP differ in population and usage





Source: US Census Bureau, Statistics Canada and Energy Velocity

Summary of TFP features in case studies

Jurisdiction	Company	Length of term	X Factor	Inflation Factor	Other features
California	Southern California Edison (SCE)	6 years	Rolling with 1.5% average	CPI	ESM and Z factor
	San Diego Gas and Electric (SDG&E)	4 years	Rolling with 1.5% average	Industry specific	ESM and Z factor
Ontario	All distribution companies	3 years	0.72% plus 0.2-0.6% stretch factors	GDP-IPI	Z factor, incremental capital module
Maine	Central Maine Power (CMP)	7 years	Rolling with 2.57% average	GDP Price Index	ESM and Z factor
	Bangor Hydro Electric Company	6 years	Rolling with 2.4% average	GDP Price Index	ESM and Z factor
Massachusetts	Nstar	7 years	Rolling with 0.63% average	GDP Price Index	ESM and Z factor

Plan of presentation

- Overview of North America
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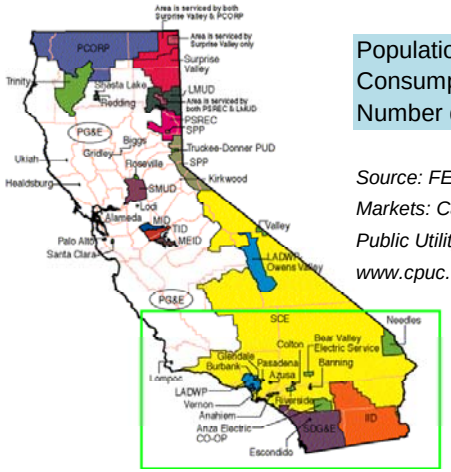
California is dominated by three distcos and rate design is influenced by the 2000-01 crisis

- Three major investor-owned utilities are PG&E, SCE and SDG&E, which serve over 2/3rds of state customers
- Challenges include growing load, particularly into more remote areas, and natural disasters (e.g. wildfires)
- Distcos severely affected by 2000-01 electricity crisis, which bankrupted the largest utility PG&E and forced a return to cost of service regulation:
  - Severe criticism at regulatory and trading arrangements, including price cap on rates, no pass through of underlying costs and no ability to hedge against spot price
  - Return to vertically integrated cost of service plus ROE regulation following crisis. PBR continued only in meeting specified performance targets

Market snapshot - California

Key facts



Population	36.5 million
Consumption	242.5TWh
Number distcos	41

Source: FERC "Electric Power Markets: California" and California Public Utility Commission www.cpuc.ca.gov/puc

California Public Utilities Commission

- Responsible for regulating privately owned electric, natural gas, telecommunications, water, railroad, rail transit and passenger transportation companies
- Staff of over 1,000
- Responsibilities in electricity include: ensuring provision of safe and reliable utility service and infrastructure; determining reasonable rates; environmental enhancement; and supporting the Californian economy

There was no universal model during California's experiments with TFP prior to crisis

	SCE	SDG&E
Form and coverage:	***Comprehensive price cap index covering capital and operations, maintenance and administration.***	***Comprehensive price cap index covering capital, operations, maintenance and administration***
Length:	***6 years (1997-2002)***	***4 years (1999-2002)***
Inflation measure:	***Consumer Price Index***	***Industry specific, using combination of national and local historical and forecast data and calculating weighted average***
X Factor and stretch factors:	***Rolling X Factor: 1.2% in 1997, 1.4% in 1998, and 1.6% in 1999-02 .*** ***Based on historical performance by Edison of 0.9% for non-generation plus a stretch factor that increases over time from 0.3% to 0.7%***	***Rolling X Factor: 1.32% in 2000, 1.47% in 2001 and 1.62% in 2002.*** ***Based on historical study of US utilities over 20 year period resulting in productivity factor of 0.92%, plus stretch factor that increases from 0.4% to 0.55% to 0.7% in line with similar stretch factors in Southern California Gas's PBR case***

Source: SCE, various documents from "Application of SCE for Authority to Implement a Distribution Performance-Based Ratemaking Mechanism", D.96-09-092; SDG&E, various documents from "Application of SDG&E for Authority to Implement a Distribution Performance-Based Ratemaking Mechanism", D.99-05-030

With the last PBR case, TFP issues focused on choice of productivity study

- **Substantial disagreement on basis for determining productivity factor:**
  - **Office of Ratepayers wanted X to reflect economic consultant study of 2.08% average TFP from 1984-94; the Federal Executive Agency used own multi-factor productivity analysis yielding 1.17%; SDG&E wanted US utility sample of 0.92%**
  - **SDG&E believed no reason for stretch factor in presence of ESM**
  - **CPUC took middle ground**
- **Little disagreement over inflation**
- **Price cap regulation not renewed following 2001-02 crisis, although CPUC still require private utilities to report on own TFP**

Non-TFP issues

- Earnings sharing mechanism proposal by SDG&E for a 100 basis point deadband over the authorized ROE was seen as "too wide" and the 20% revenue sharing by ratepayers outside the deadband "too low"
- Decision for deadband of 25 basis points above ROE, with eight bands of shareholder/ consumer sharing:

Bands (above authorized ROE)	Shareholders	Ratepayers
25-75 basis points	25%	75%
75-100 basis points	35%	65%
100-125 basis points	45%	55%
125-150 basis points	55%	45%
150-175 basis points	65%	35%
175-200 basis points	75%	25%
200-250 basis points	85%	15%
250-300 basis points	95%	5%

- Z factor according to 9 criteria adopted in previous PBR gas and SCE cases
- Since crisis, continuation of incentive-based performance standards until this year. CPUC found reporting violations by SCE on performance measurements. SCE and SDG&E ratecases this year do not have PBR elements

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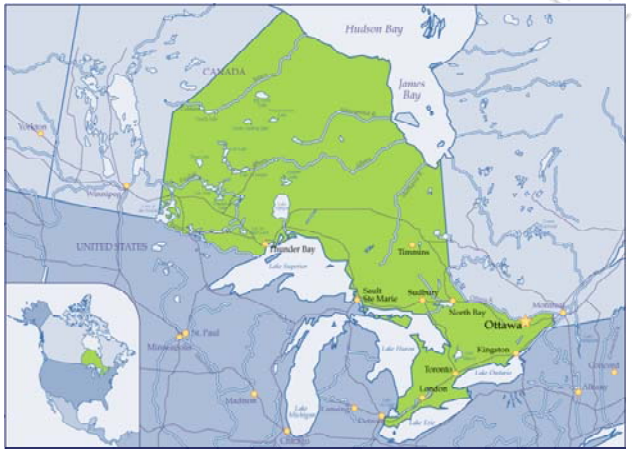
Ontario is unique environment with a large and diverse number of distcos

- Over 80 publicly and privately owned distcos; most are recently corporatized municipal utilities
- State of flux earlier in decade with considerable merger activity
- Ontario distcos face unique weather conditions and customer base, and a distinct legacy of system configuration and network expansion due to government and municipal ownership, which impacts the choice of inputs
- Significant heterogeneity in distcos:
  - size – range from 2,400 to 1.3 million customers
  - customer mix and service area
  - asset state – different technologies used and different age of assets

Market snapshot - Ontario



Key facts

Population (2007)	12.7 million
Consumption (2007)	153.5TWh
Number distribution companies:	83
Main companies: Hydro One, municipal utilities	

Source: OEB "Energy Statistics" available on www.oeb.gov.on.ca

Ontario Energy Board

- Has regulated distcos in electricity since 1998, and natural gas since 1960
- Staff of 175
- Responsible for rate setting; licensing market participants; approval of transmission lines; approval of mergers and acquisitions; and market monitoring

Ontario will be using from 2009 a GDP deflator, US 18 year average TFP for X, and stretch factors

Form and coverage:	***Comprehensive price cap index covering capital and operations, maintenance and administration. Now on third generation***
Length:	***3 years (rebasing year plus one)***
Inflation measure:	***In second and third generation, GDP deflator (GDP- IPI) favored over comprehensive industry inflation index, due to concerns over weightings of sub-components.***
X Factor:	***Use of simple 18 year US distribution company average of 0.72%***
Stretch factors:	***Distributors assigned to three groups with different stretch factors – superior (0.2%); average (0.4%); and inferior (0.6%)***
Benchmarking evalution:	***Two evaluations using most recent 3 year operations, maintenance and administration cost data:*** ***1.Use of econometric model to determine distco costs, controlling for factors beyond management control (number of customers served, kWh delivered, price of inputs, percent of distribution lines underground) and compare predicted and actual costs*** ***2.Compare distcos' operations, maintenance and administration costs per unit of output to average unit cost of a peer group***

Source: Various documents from "3rd Generation Incentive Regulation", EB-2007-0673

Note: LEI advised the Coalition of Large Distributors on matters related to the 3GIRM process in Ontario

The main issues in the recent TFP setting were missing data, benchmarking and misclassification

- **Disagreement on basis for determining productivity factor:**
  - Use local level information, but missing data if 20 year average of Ontario firms taken
  - Use starting year analysis, choosing a year most similar in economic conditions, weather conditions, etc.
  - Questions of how to avoid misclassification of distcos if multiple stretch factors used
- **Choice of macroeconomic or industrial price index:**
  - Both had precedent in Ontario: IPI for Phase I, macroeconomic price for Phase II and gas
  - IPI seen as superior, but problems over reasonableness and consistency of input price indices with costs, and weightings of indices

Rejection of "menu approach"

- Suggestion by intervenor in Phases I and III to link the X factor with an ROE ceiling. Considered, but ultimately rejected, by the OEB
- "Menu approach" would have allowed distcos to choose their own combination:

Selection	X Factor (%)	ROE Ceiling (%)
A	1.25	10
B	1.50	11
C	1.75	12
D	2.00	13
E	2.25	14
F	2.50	15

Source: OEB. 2000. "RP-1999-0034. Decision with Reasons". January 18, 2000

In non-TFP issues, disagreement centered on incremental capital

- Original proposal for asymmetric earnings sharing mechanism dropped. Distco association wanted symmetrical and differential treatment for private and publicly owned utilities
- Z factor, allowing for unforeseen events, allowed, but question of threshold in relation to total revenue requirement:
  - In end, differentiation depending on size of revenue requirement ($50,000 if less than $10 million; 0.5% if less than $200 million; and $1 million if over)
- Need for incremental capital funding generally recognized, because the ratebase has been growing faster than rates under the price cap:
  - Use of formula linking capex with depreciation favored by OEB Board over single number threshold
  - Argument that 125% threshold correlated with ≥2% growth in ratebase accepted by Board. Consumer groups pushed for 200%

Signs of growing interest in Western Canada

- In Alberta, Enmax Power Corporation (EPC) awaiting decision on Performance Based Ratemaking:
  - Filing had blended inflation factor (IPI and Alberta hourly earnings)
  - X factor of 1.5% in application
  - Intervenor disagreement on TFP centered on EPC's position on efficiency frontier and sample group of utilities for TFP analysis

- In British Columbia:
  - Largest utility BC Hydro has signaled desire to move to PBR in next rate application, due in FY2009
  - Fortis BC also shown interest

Note: LEI advised EPC on matters associated with its filing

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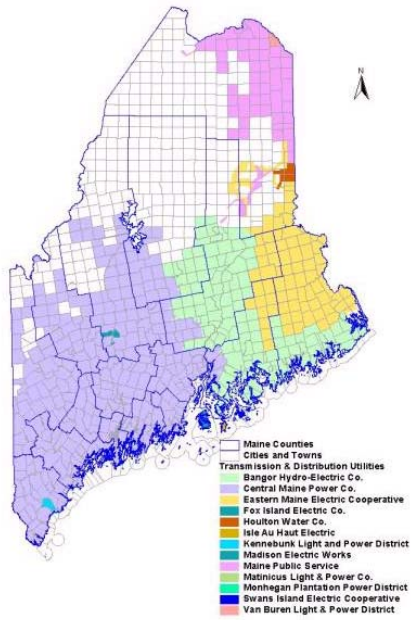
Maine relies on TFP for its two major private utilities; promoting efficiency is explicit objective

- Dominated by three investor owned utilities - Central Maine Power (CMP), Bangor Hydro-Electric Company, and Maine Public Service Company
- Major mergers in last decade between Bangor Hydro and Emera, and CMP and Energy East
- Weather cited by distcos as the major unknown variable affecting O&M and capital costs
- Maine PUC:
  - Statutory obligation to adopt rate mechanisms that promote electric utility efficiency
  - Staff of 75
  - Also regulate ferries and water taxies, natural gas, telecommunications and water

Market snapshot - Maine



Key facts

Population	1.3 million
Consumption	12.0 TWh
Number distcos	3 IOUs and 7 municipal-owned

Source: FERC "Electric Power Markets: ISO-NE" and Maine Public Utility Commission, www.maine.gov/mpuc

Maine favors a macroeconomic price index and rolling X factor

Form and coverage:	***Comprehensive price cap index covering Central Maine Power Company and Bangor Hydro-Electric Company. Known in state as "Alternative Rate Plans"***
Length:	***7 years (2001-2007) for CMP; 6 years (2002-07) for Bangor. Next phase still to be determined***
Inflation measure:	***GDP-PI chosen due to ease of understanding of macroeconomic price indices. As measured by US Commerce Department***
X Factor and stretch factor:	***For CMP: rolling X factor averaging 2.57% over period (equal to inflation in 2001; 2% in 2002; 2.25% in 2003; 2.75% in 2004-06; and 2.9% in 2007)*** ***Board decision favored Advisory staff analysis using variety of different sources:*** ***1.TFP study of CMP (historical 20 years) by consultant with adjustments (more current time period, an unweighted sample group, and removal of input price differentials)*** ***2.Alternative productivity analysis looking at changes in real distribution cost of service per kWh for 113 North American utilities*** ***3.Inclusion of stretch factor based on staff regression analysis, measuring additional levels of productivity that could be expected by CMP based on current productivity levels compared to the industry average*** ***For Bangor: X factors were designed to be in line with average for CMP, but accounting for initial differences in regression analysis of stretch factor and company desire for lower X at end of period (2.5% in 2003, 2.75% in 2004-05; and 2% in 2006-07)***

Source: CMP, various documents from "Request for Approval of Alternative Rate Plan (Post-Merger)", Docket No. 99-666; Bangor, various documents from "Request for Approval of Alternative Rate Plan", Docket No. 2001-410

TFP issues for CMP focused on size of the stretch factor and length of period

- Disagreement with CMP centered on how much to adjust X factor from consultant study:
  - Economic consultant's study found historical TFP for company of 1.5%
  - CMP only wanted inclusion of 0.25% stretch factor from 2004-07
  - Office of the Public Advocate and the Board advisory staff recommended higher stretch factors on own analysis of company's relative efficiency
- Disagreement on length of period. Consumers and Board advisory staff wanted 5 years.
- Final settlement – supported Board staff on TFP, supported company on length of period
- Ongoing ratecase with Central Maine Power Company and Bangor for new 7 year PBR

Non-TFP issues

- Z factor became contentious area over coverage of mandated costs and treatment of expiring amortizations associated with a prior ice storm, deferred demand side management and employee transition costs
- Asymmetrical earnings sharing: no top end sharing due to higher stretch factor and revenue deficiencies below 5.2% ROE shared 50/50 between shareholders and ratepayers

TFP also used in Massachusetts to inform rate design as part of Nstar settlement agreement

- Recently been implemented in Massachusetts with the largest utility Nstar, following merger of Cambridge, Commonwealth, and Canal Electric Company with Boston Edison:
  - 7 year PBR term (2006-12), use of GDP-PI as inflation factor and rolling X factor averaging 0.63% (0.5% in 2007 increasing to 0.75% in 2012).
  - X factor determined in Settlement Agreement. According to MA Department of Public Utilities, no independent analysis conducted on X factor, being determined by "black box approach"
  - Informed heavily by practice in Maine, including use of GDP-PI and rolling X factor
- Settlement Agreement following merger of Massachusetts Electric Company (National Grid) and Eastern Edison Company:
  - Implicit benchmarking in 1999 agreement regarding 2005-09 rates
  - During this period, distribution rates being adjusted annually based on average of rate changes of investor owned utilities in New England, New York, New Jersey and Pennsylvania

Concluding remarks

- TFP analysis not used extensively for rate setting in North America, although signs of renewed interest in Canada
- Heterogeneity of North American utilities makes comparative TFP studies challenging
- Where implemented, there is no universal model:
  - Some jurisdictions have favored company specific TFP studies, others sample of North American utilities
  - Common use of stretch factor, which is often part of bargaining process between the company and other interveners on overall ratemaking formula
  - Use of both macroeconomic price indices and industrial price indices
- Despite improved incentive properties, there appears to be little momentum towards greater use of I-X formulations based on TFP analysis

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure

- **Regulatory economics** practice anchored in knowledge of competitive wholesale market design, market power analysis, and of PBR
- **Asset valuation** activities include both generation and wires assets, as well as other infrastructure sectors
- **Strategy** engagements include regional investment allocation for IPPs or value chain analysis for currently integrated utilities
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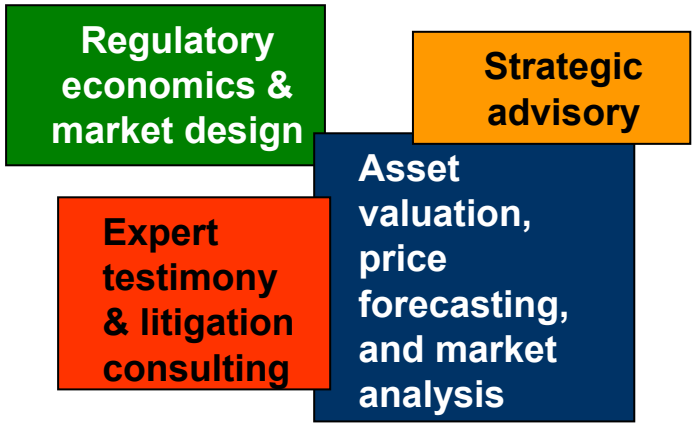

Representative Clients

Utilities and IPPs	Regulators/Market institutions	Financial institutions
AES	*Alberta Department of Energy*	*AIG*
Brookfield Power	*Alberta Electric System Operator*	*Development Bank of Japan*
Emera	*California Energy Commission*	*GE Capital*
ENEL	*California ISO*	*Fifth Third Bank*
ENMAX	*Connecticut Dept of Public Utility Control*	*Inter-American Development Bank*
Huaneng Power Int'l	*Electricity & Cogeneration Regulatory*	*John Hancock*
Hydro Quebec	*Authority (Saudi Arabia)*	*Macquarie Bank*
KeySpan Energy	*Hong Kong Government*	*World Bank*
National Grid	*Maine Public Utility Commission*	
Northeast Utilities	*NEMMCO (Australia)*	
Osaka Gas	*New England ISO*	
Tata Power	*Ontario Energy Board*	
TransAlta	*Ontario Power Authority*	

Personal and firm experience cross cutting with regards to electricity sector policy, regulation, and valuation issues

President:

London Economics International LLC

economic and financial advisory services for energy and infrastructure worldwide

- served as expert on performance-based ratemaking and cost of capital in two Canadian provinces
- advised regulator on new generation, transmission and distribution electricity tariff regime in Saudi Arabia
- advised on successful bid for Singapore genco by Chinese investor
- oversees asset management for several renewable energy projects
- submitted testimony to Public Utility Commission in Texas on market power issues related to largest IOU in Texas
- analysed market power implications of acquisition of PSEG in New Jersey
- advised on new Scheme of Control for Hong Kong regulator
- multiple generation engagements in Asia, Africa and Latin America