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A – ADMINISTRATIVE AND MODEL DESIGN

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	3	1	Approvals Requested	R. Bourke
	4	1	Draft Issues List	R. Bourke
	5	1	Conditions of Service	T. Ferguson S. McGill
		2	Schedule of Service Charges – Rider G	S. McGill M. Torriano
	6	1	Curriculum Vitae of Company Witnesses	R. Bourke
		2	Curriculum Vitae of Company Witnesses	M. Lister
		3	Curriculum Vitae of Julia Frayer – London Economics	M. Lister
		4	Curriculum Vitae of Concentric Consultants	M. Lister
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A – ADMINISTRATIVE AND MODEL DESIGN

Exhibit	Tab	Schedule	Contents	Witness(es)
A2	1	2	IR Plan Productivity	R. Fischer S. Kancharla M. Lister A. Mandyam
		3	Challenge of I-X	R. Fischer S. Kancharla M. Lister
	2	1	Rate Adjustment Proposal - 2014 Fiscal Year	K. Culbert A. Kacicnik R. Fischer M. Lister
	3	1	Annual Rate Adjustment Proposal -	K. Culbert A. Kacicnik R. Fischer M. Lister
		2	Summary of IR Application Purposes & Timing (Material Circulated at the October 11, 2013 Information Session)	K. Culbert
	4	1	Z Factor Proposal	R. Fischer M. Lister
	5	1	Cost of Capital	K. Culbert R. Fischer M. Lister M. Suarez
	6	1	Off-Ramp Proposal	K. Culbert R. Fischer M. Lister
	7	1	Earnings Sharing Mechanism (“ESM”) Proposal	R. Fischer M. Lister

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A – ADMINISTRATIVE AND MODEL DESIGN

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	9	1	Incentive Ratemaking Report	J. Coyne J. Simpson Concentric Energy Advisors Inc.
	10	1	The Building Blocks Approach to Incentive Regulation	J. Frayer Consultant - London Economics International LLC
	11	1	Service Quality Requirements (“SQR’s”)	L. Cowie T. Ferguson K. Lakatos-Hayward M. Torriano
		2	Performance Measurement Framework	S. Kancharla A. Mandyam P. Squires
		3	Sustainable Efficiency Incentive Mechanism (“SEIM”)	R. Fischer S. Kancharla M. Lister A. Mandyam P. Squires

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		2	Rate Base - Year to Year Summary	K. Culbert
	2	1	Economic Feasibility Procedure and Policy	F. Ahmad P. Squires
	3	1	Community Expansion	T. MacLean D. McIlwraith
Capital Expenditure Budget by Business Area				
B2	1	1	Capital Budget Overview	A. Mandyam J. Sanders
	2	1	Capital Budget: 2014 to 2016 Growth	F. Ahmad D. Lapp
	3	1	Capital Business Area - Reinforcements	E. Naczynski
		2	Capital Business Area - Major Reinforcements	C. Fernandes D. Lapp
	4	1	Capital Business Area - Relocations	L. Chiotti I. Taylor
	5	1	Capital Business Area – System Integrity and Reliability - Overview	L. Lawler J. Sanders
		2	Capital Requirements - Mains Replacement	D. Lapp L. Lawler J. Sanders
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B – RATE BASE AND CAPITAL EXPENDITURES

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		5	System Integrity & Reliability – Other Programs & Projects 2014 to 2016	A. Creery C. McCowan
		6	System Integrity & Reliability: Direct Resource Costs	A. Mandyam J. Sanders
	6	1	Capital Business Area – Storage	D. Dalpe B. Pilon
	7	1	Capital Business Area - Business Development	R. Murray
	8	1	Capital Business Area - Information Technology	T. Adesipo B. Misra
		2	Work and Asset Management Solution (“WAMS”)	W. Akkermans M. Brophy
	9	1	Capital Business Area - Facilities and General Plant	D. Lapp P. Rapini R. Riccio
	10	1	The Company’s Asset Plan 2013-2022	L. Chiotti

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B3	1	1	Utility Rate Base - 2014 Fiscal Year	K. Culbert
		2	Utility PP&E (excluding CC/CIS) 2014 Summary & AOMA's	K. Culbert
		3	Working Capital Components – 2014 Fiscal Year	K. Culbert

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B3	2	1	2014 to 2016 Gross Customer Additions	F. Ahmad L. Au T. Knight
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B4	1	1	Utility Rate Base - 2015 Forecast	K. Culbert
		2	Utility PP&E (excluding CC/CIS) 2015 Summary & AOMA's	K. Culbert
		3	Working Capital Components – 2015 Forecast	K. Culbert
2016 Rate Base Forecast				
B5	1	1	Utility Rate Base - 2016 Forecast	K. Culbert
		2	Utility PP&E (excluding CC/CIS) 2016 Summary & AOMA's	K. Culbert
		3	Working Capital Components – 2016 Forecast	K. Culbert
2017 Rate Base Forecast				
B6	1	1	Utility Rate Base - 2017 Forecast	K. Culbert
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		3	Working Capital Components – 2017 Forecast	K. Culbert

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B – RATE BASE AND CAPITAL EXPENDITURES

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		2	Utility PP&E (excluding CC/CIS) 2018 Summary & AOMA's	K. Culbert
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	3	1	Transactional Services (TS)	J. Denomy J. LeBlanc D. Small
	4	1	Other Service Charges, Administrative and Late Payment Penalty (LPP) Revenue	S. McGill M. Torriano
	5	1	GTA Project Revenue Requirement And Revenue Requirement for Shared Pipeline with TransCanada	K. Culbert C. Fernandes A. Kacicnik
Economic Forecasts				
C2	1	1	Key Economic Assumptions	H. Sayyan M. Suarez
		2	Heating Degree Day Forecast	H. Sayyan M. Suarez
		3	Average Use Forecasting Model	H. Sayyan M. Suarez
2014 Fiscal Year Revenue				
C3	1	1	Utility Operating Revenue 2014 Fiscal Year	K. Culbert

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
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	2	1	Customers, Volumes and Revenues by Rate Class - 2014 Fiscal Year	R. Cheung S. Qian
		2	Comparison of Average Customer Numbers by Rate Class 2014 Fiscal Year and 2013 Board Approved	R. Cheung S. Qian
		3	Comparison of Gas Sales and Transportation Volume by Rate Class 2014 Fiscal Year and 2013 Board Approved	R. Cheung S. Qian
		4	Comparison of Gas Sales and Transportation Revenue by Rate Class 2014 Budget and 2013 Board Approved	R. Cheung S. Qian
	3	1	Details of Other Revenue 2014 Fiscal Year and 2013 Board Approved	R. Lei S. Qian
	4	1	NGV Rate of Return 2014 to 2016	F. Ahmad K. Culbert M. Tremayne

2015 Revenue Forecast

Exhibit	Tab	Schedule	Contents	Witness(es)
C4	1	1	Utility Operating Revenue 2015 Forecast	K. Culbert
		2	Comparison of Utility Operating Revenue 2015 Forecast and 2014 Fiscal Year	R. Lei S. Qian

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
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		2	Comparison of Average Customer Numbers by Rate Class 2015 Forecast and 2014 Fiscal Year	R. Cheung S. Qian
		3	Comparison of Gas Sales and Transportation Volume by Rate Class 2015 Forecast and 2014 Fiscal Year	R. Cheung S. Qian
		4	Comparison of Gas Sales and Transportation Revenue by Rate Class 2015 Forecast and 2014 Fiscal Year	R. Cheung S. Qian
	3	1	Details of Other Revenue 2015 Forecast and 2014 Fiscal Year	R. Lei S. Qian

2016 Revenue Forecast

Exhibit	Tab	Schedule	Contents	Witness(es)
C5	1	1	Utility Operating Revenue 2016 Forecast	K. Culbert
		2	Comparison of Utility Operating Revenue 2016 Forecast and 2015 Forecast	R. Lei S. Qian
	2	1	Customers, Volumes and Revenues by Rate Class - 2016 Forecast	R. Cheung S. Qian
		2	Comparison of Average Customer Numbers by Rate Class 2016 Forecast and 2015 Forecast	R. Cheung S. Qian
		3	Comparison of Gas Sales and Transportation Volume by Rate Class 2016 Forecast and 2015 Forecast	R. Cheung S. Qian

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
C5	2	4	Comparison of Gas Sales and Transportation Revenue by Rate Class 2016 Forecast and 2015 Forecast	R. Cheung S. Qian
	3	1	Details of Other Revenue 2016 Forecast and 2015 Forecast	S. Kancharla R. Lei S. Qian

2017 Revenue Forecast

Exhibit	Tab	Schedule	Contents	Witness(es)
C6	1	1	Utility Operating Revenue 2017 Forecast Year	K. Culbert
		2	Comparison of Utility Operating Revenue 2017 Forecast and 2016 Forecast	R. Cheung S Qian
	2	1	Customer Meters and Volumes by Rate Class 2017 Forecast	R. Cheung S. Qian
		2	Comparison of Average Customer Meters by Rate Class 2017 Forecast and 2016 Forecast	R. Cheung S. Qian
C7	1	1	Utility Operating Revenue 2018 Forecast Year	K. Culbert
		2	Comparison of Utility Operating Revenue 2018 Forecast and 2017 Forecast	R. Cheung S Qian
	2	1	Customer Meters and Volumes by Rate Class 2018 Forecast	R. Cheung S. Qian
		2	Comparison of Average Customer Meters by Rate Class 2018 Forecast and 2017 Forecast	R. Cheung S. Qian

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D – OPERATING & MAINTENANCE COSTS

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	2	1	Gas Costs, Transportation and Storage	J. Denomy D. Small
		2	Status of Transportation Contracts	J. Denomy D. Small
	3	1	Operating Maintenance Costs	S. Kanchanla R. Lei A. Mandyam M. Torriano
		2	Employee Expenses and Workforce Demographics	M. Lee S. Trozzi
	4	1	Corporate Cost Allocation (“CAM”)	S. Chhelavda L. Liauw B. Yuzwa
	5	1	Depreciation Rate Change	L. Au A. Mandyam B. Yuzwa
	6	1	Municipal Taxes	B. Remington
	7	1	DSM Budget	F. Oliver-Glasford
	8	1	Deferral and Variance Accounts	K. Culbert D. Small
		2	GTA Project Variance Account	K. Culbert C. Fernandes

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
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		4	Customer Care Services Procurement Deferral Account	K. Culbert K. Lakatos-Hayward S. McGill
		5	Greenhouse Gas Emission Impact Deferral Account ("GGEIDA")	T. Adamson K. Culbert
		6	Relocation & Replacement Mains Variance Accounts	K. Culbert J. Sanders
	9	1	Open Bill Access	K. Lakatos-Hayward S. McGill
	10	1	CIS / Customer Care – A Review of the Treatment of CIS/Customer Care Costs as a Result of the ADR Settlement in EB-2011-0226	K. Culbert K. Lakatos-Hayward S. McGill
		2	EB-2011-0226 Settlement Agreement Enbridge Customer Care and CIS Costs 2013 to 2018 - September 2, 2011	K. Culbert K. Lakatos-Hayward S. McGill
		3	Updated CIS/CC Template for 2014 to 2018	K. Culbert S. McGill
	11	1	Finance - O&M Budget	S. Chhelavda S. Kancharla B. Yuzwa
	12	1	Law Department – O&M Budget	L. Cornwall

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C – OPERATING REVENUE

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C – OPERATING REVENUE

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	2	1	Cost Comparison of Utility Operating Cost and Expenses 2014 Fiscal Year and 2013 Board Approved	S. Kancharla R. Lei
	2	2	2014 Fiscal Year Operating & Maintenance Expense by Department	S. Kancharla R. Lei
		3	Operating and Maintenance Expense by Cost Type - 2014 Fiscal Year vs. 2013 Board Approved	S. Kancharla R. Lei
		4	2014 Fiscal Year - Salaries & Wages and FTE Forecast	S. Kancharla R. Lei S. Trozzi
	3	1	2014 Fiscal Year Summary of Gas Cost Charged to Operations	J. Denomy D. Small
		2	2014 Fiscal Year Summary of Storage and Transportation Costs	J. Denomy D. Small
		3	2014 Fiscal Year Peak Day Supply Mix	J. Denomy D. Small
		4	2014 Fiscal Year Monthly Pricing Information	J. Denomy D. Small
		5	2014 Fiscal Year Gas Supply/Demand	J. Denomy D. Small
	4	1	2014 Fiscal Year Unbilled and Unaccounted-for (UAF) Gas Volumes	H. Sayyan M. Suarez

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
2015 Forecast				
D4	1	1	Utility Operating Costs 2015 Forecast	K. Culbert
	2	1	Cost Comparison of Utility Operating Cost and Expenses 2015 Forecast and 2014 Fiscal Year	S. Kancharla R. Lei
		2	2015 Forecast Operating & Maintenance Expense by Department	S. Kancharla R. Lei
		3	Operating and Maintenance Expense by Cost Type - 2015 Forecast vs. 2013 Board Approved	S. Kancharla R. Lei
		4	2015 Forecast - Salaries & Wages and FTE Forecast	S. Kancharla R. Lei S. Trozzi
	3	1	2015 Gas Cost, Transportation and Storage	J. Denomy D. Small
		2	2015 Forecast Summary of Gas Cost Charged to Operations	J. Denomy D. Small
		3	2015 Forecast Summary of Storage and Transportation Costs	J. Denomy D. Small
		4	2015 Forecast Peak Day Supply Mix	J. Denomy D. Small
		5	2015 Forecast Monthly Pricing Information	J. Denomy D. Small
		6	2015 Forecast Gas Supply/Demand	J. Denomy D. Small

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
D4	4	1	2015 Forecast Unbilled and Unaccounted-for (UAF) Gas Volumes	H. Sayyan M. Suarez
2016 Forecast				
D5	1	1	Utility Operating Costs 2016 Forecast	K. Culbert
	2	1	Cost Comparison of Utility Operating Cost and Expenses 2016 Forecast and 2015 Forecast	S. Kancharla R. Lei
		2	2016 Forecast Operating & Maintenance Expense by Department	S. Kancharla R. Lei
		3	Operating and Maintenance Expense by Cost Type - 2016 Forecast vs. 2013 Board Approved	S. Kancharla R. Lei
		4	2016 Forecast - Salaries & Wages and FTE Forecast	S. Kancharla R. Lei S. Trozzi
	3	1	2016 Gas Cost, Transportation and Storage	J. Denomy D. Small
		2	2016 Forecast Summary of Gas Cost Charged to Operations	J. Denomy D. Small
		3	2016 Forecast Summary of Storage and Transportation Costs	J. Denomy D. Small
		4	2016 Forecast Peak Day Supply Mix	J. Denomy D. Small

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
D5	3	5	2016 Forecast Monthly Pricing Information	J. Denomy D. Small
		6	2016 Forecast Gas Supply/Demand	J. Denomy D. Small
	4	1	2016 Forecast Unbilled and Unaccounted-for (UAF) Gas Volumes	H. Sayyan M. Suarez

2017 Forecast

Exhibit	Tab	Schedule	Contents	Witness(es)
D6	1	1	Cost of Service 2017 Forecast Year	K. Culbert
	2	1	Cost Comparison of Utility Operating Cost and Expenses 2017 Forecast and 2016 Forecast	S. Kancharla R. Lei
		2	2017 Forecast Operating & Maintenance Expense by Department	S. Kancharla R. Lei
		3	Operating and Maintenance Expense by Cost Type - 2017 Forecast vs. 2013 Board Approved	S. Kancharla R. Lei
		4	FTE and Salaries & Wages 2017 Budget Year	S. Kancharla R. Lei S. Trozzi

2018 Forecast

Exhibit	Tab	Schedule	Contents	Witness(es)
D7	1	1	Cost of Service 2018 Forecast Year	K. Culbert
	2	1	Cost Comparison of Utility Operating Cost and Expenses 2018 Forecast and 2017 Forecast	S. Kancharla R. Lei

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
D7	2	2	2018 Forecast Operating & Maintenance Expense by Department	S. Kancharla R. Lei
		3	Operating and Maintenance Expense by Cost Type - 2018 Forecast vs. 2013 Board Approved	S. Kancharla R. Lei
		4	FTE and Salaries & Wages 2018 Budget Year	S. Kancharla R. Lei S. Trozzi

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E – COST OF CAPITAL

Exhibit	Tab	Schedule	Contents	Witness(es)
Written Evidence Capital Structure				
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	2	1	Cost of Capital 2014 to 2016	P. Bhatia S. Kancharla
		2	Cost of Capital 2017 and 2018	P. Bhatia
Special Studies and Reports				
E2	1	1	Return on Equity Calculations for 2014 through 2016	M. Lister S. Murray
		2	Return on Equity Calculations for 2017 and 2018	P. Bhatia M. Suarez
2014 Fiscal Year Capital Structure				
E3	1	1	Cost of Capital 2014 Fiscal Year	K. Culbert
		2	2014 Fiscal Year Summary Statement of Principal and Carrying Costs of Term Debt	K. Culbert
		3	2014 Fiscal Year Unamortized Debt Discount and Expense Average of Monthly Averages	K. Culbert
		4	2014 Fiscal Year Preference Shares Summary Statement of Principal and Carrying Cost	K. Culbert
		5	2014 Fiscal Year Unamortized Preference Share Issue Expense Average of Monthly Averages	K. Culbert

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E – COST OF CAPITAL

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E – COST OF CAPITAL

Exhibit	Tab	Schedule	Contents	Witness(es)
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2017 Forecast Capital Structure

Exhibit	Tab	Schedule	Contents	Witness(es)
E6	1	1	Cost of Capital 2017 Forecast Year	K. Culbert
		2	2017 Forecast Summary Statement of Principal and Carrying Costs of Term Debt	K. Culbert
		3	2017 Forecast Unamortized Debt Discount and Expense Average of Monthly Averages	K. Culbert
		4	2017 Forecast Preference Shares Summary Statement of Principal and Carrying Cost	K. Culbert
		5	2017 Forecast Unamortized Preference Share Issue Expense Average of Monthly Averages	K. Culbert

2018 Forecast Capital Structure

Exhibit	Tab	Schedule	Contents	Witness(es)
E7	1	1	Cost of Capital 2018 Forecast Year	K. Culbert
		2	2018 Forecast Summary Statement of Principal and Carrying Costs of Term Debt	K. Culbert
		3	2018 Forecast Unamortized Debt Discount and Expense Average of Monthly Averages	K. Culbert

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E – COST OF CAPITAL

Exhibit	Tab	Schedule	Contents	Witness(es)
E7	1	4	2018 Forecast Preference Shares Summary Statement of Principal and Carrying Cost	K. Culbert
		5	2018 Forecast Unamortized Preference Share Issue Expense Average of Monthly Averages	K. Culbert

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F – REVENUE SUFFICIENCY/DEFICIENCY

Exhibit	Tab	Schedule	Contents	Witness(es)
Written Evidence				
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		2	Allowed Revenue (Deficiency)/Sufficiency 2014 to 2016	K. Culbert
		3	Allowed Revenue (Deficiency)/Sufficiency 2017 to 2018	K. Culbert
2014 Fiscal Year				
F3	1	1	2014 Fiscal Year Revenue Sufficiency Calculation And Required Rate Of Return	K. Culbert
		2	Utility Income 2014 Fiscal Year	K. Culbert
		3	Utility Rate Base 2014 Fiscal Year	K. Culbert
2015 Forecast Revenue				
F4	1	1	2015 Forecast Revenue Deficiency Calculation And Required Rate Of Return	K. Culbert
		2	Utility Income 2015 Forecast	K. Culbert
		3	Utility Rate Base 2015 Forecast	K. Culbert

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F – REVENUE SUFFICIENCY/DEFICIENCY

Exhibit	Tab	Schedule	Contents	Witness(es)
2016 Forecast Revenue				
F5	1	1	2016 Forecast Revenue Deficiency Calculation And Required Rate Of Return	K. Culbert
		2	Utility Income 2016 Forecast	K. Culbert
		3	Utility Rate Base 2016 Forecast	K. Culbert
2017 Forecast Revenue				
F6	1	1	2017 Forecast Revenue Deficiency Calculation and Required Rate of Return	K. Culbert
		2	Utility Income 2017 Forecast	K. Culbert
		3	Utility Rate Base 2017 Forecast	K. Culbert
2018 Forecast Revenue				
F7	1	1	2018 Forecast Revenue Deficiency Calculation and Required Rate of Return	K. Culbert
		2	Utility Income 2018 Forecast	K. Culbert
		3	Utility Rate Base 2018 Forecast	K. Culbert

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Exhibit	Tab	Schedule	Contents	Witness(es)
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2014 Fiscal Year				
G2	1	1	Fully Allocated Cost Study - 2014 Fiscal Year	A. Kacicnik M. Kirk
	2	1	Revenue to Cost/Rate of Return Comparisons	A. Kacicnik M. Kirk
		2	Revenue to Cost/Rate of Return Comparisons Excluding Gas Supply Commodity	A. Kacicnik M. Kirk
	3	1	Functionalization of Utility Rate Base	A. Kacicnik M. Kirk
		2	Functionalization of Utility Working Capital	A. Kacicnik M. Kirk
		3	Functionalization of Utility Net Investments	A. Kacicnik M. Kirk
		4	Functionalization of Utility O&M	A. Kacicnik M. Kirk
	4	1	Classification of Rate Base	A. Kacicnik M. Kirk
		2	Classification of Net Investment	A. Kacicnik M. Kirk
		3	Classification of O&M Costs	A. Kacicnik M. Kirk

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G – COST ALLOCATION

Exhibit	Tab	Schedule	Contents	Witness(es)
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		2	Allocation of Return & Taxes	A. Kacicnik M. Kirk
		3	Allocation of Total Cost of Service	A. Kacicnik M. Kirk
	6	1	Rate Base Functionalization Factors	A. Kacicnik M. Kirk
		2	Classification of Gas Costs to Operations	A. Kacicnik M. Kirk
		3	Allocation Factors	A. Kacicnik M. Kirk
		4	Allocation of DSM Program Costs General Costs Including Fringe Benefits and A&G	A. Kacicnik M. Kirk
	7	1	Tecumseh – Functionalization and Classification of Rate Base	A. Kacicnik M. Kirk
		2	Tecumseh – Functional Allocation of Cost of Service - 2014 Fiscal Year	A. Kacicnik M. Kirk
		3	Tecumseh – Classification of Cost of Service 2014 Fiscal Year	A. Kacicnik M. Kirk
		4	Tecumseh Gas Rate Derivation 2014 Fiscal Year	A. Kacicnik M. Kirk
		5	Tecumseh Gas Isolation of Transmission Related Rate Base 2014 Fiscal Year	A. Kacicnik M. Kirk

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G – COST ALLOCATION

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		7	Functionalization of Short Cycle Net Revenues to In/Ex Franchise Customers 2014 Fiscal Year	A. Kacicnik M. Kirk

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H – RATE DESIGN

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H – RATE DESIGN

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		2	Estimate of 2017 and 2018 – a Forward Looking Projection of Rate Impacts	J. Collier A. Kacicnik

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I – INTERROGATORIES AND RESPONSES

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I.A5.EGDI.CCC.8	CCC Interrogatories	EGDI

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I.A8.EGDI.OAPPA.1	OAPPA Interrogatories	EGDI
I.A9.EGDI.SEC.41 to 43	SEC Interrogatories	EGDI
I.A10.EGDI.STAFF.24 to 40	Board Staff Interrogatories	EGDI
I.A10.EGDI.CCC.10 to 16	CCC Interrogatories	EGDI
I.A10.EGDI.CME.4, 5, 8 and 9	CME Interrogatories	EGDI
I.A10.EGDI.EP.6 to 10	Energy Probe Interrogatories	EGDI
I.A10.EGDI.SEC.44 to 54	SEC Interrogatories	EGDI
I.A11.EGDI.CCC.17	CCC Interrogatories	EGDI
I.A11.EGDI.SEC.55 to 57	SEC Interrogatories	EGDI
I.A12.EGDI.STAFF.41 to 46	Board Staff Interrogatories	EGDI
I.A12.EGDI.BOME.4	BOMA Interrogatories	EGDI
I.A12.EGDI.SEC.58 to 63	SEC Interrogatories	EGDI

EXHIBIT LIST

I – INTERROGATORIES AND RESPONSES

Exhibit	Contents	Witness(es)
I.A13.EGDI.CCC.18	CCC Interrogatories	EGDI
I.A13.EGDI.OAPPA.3	OAPPA Interrogatories	EGDI
I.A15.EGDI.CCC.19	CCC Interrogatories	EGDI
I.A16.EGDI.EP.11 to 12	Energy Probe Interrogatories	EGDI
I.A16.EGDI.OAPPA.4	OAPPA Interrogatories	EGDI
I.A16.EGDI.SEC.64	SEC Interrogatories	EGDI
I.A16.EGDI.VECC.5	VECC Interrogatories	EGDI
Issue B		
I.B17.EGDI.STAFF.47 to 51	Board Staff Interrogatories	EGDI
I.B17.EGDI.CCC.20 to 24	CCC Interrogatories	EGDI
I.B17.EGDI.CME.13 to 14	CME Interrogatories	EGDI
I.B17.EGDI.EP.13 to 20	Energy Probe Interrogatories	EGDI
I.B17.EGDI.FRPO.1 to 16	FRPO Interrogatories	EGDI
I.B17.EGDI.SEC.65 to 79	SEC Interrogatories	EGDI
I.B17.EGDI.VECC.15, 17, 18	VECC Interrogatories	EGDI
I.B18.EGDI.STAFF.52 to 64	Board Staff Interrogatories	EGDI
I.B18.EGDI.CCC.25 to 27	CCC Interrogatories	EGDI

EXHIBIT LIST

I – INTERROGATORIES AND RESPONSES

Exhibit	Contents	Witness(es)
I.B18.EGDI.EP.21 to 25	Energy Probe Interrogatories	EGDI
I.B18.EGDI.SEC.80 to 118	SEC Interrogatories	EGDI
I.B19.EGDI.STAFF.65 to 67	Board Staff Interrogatories	EGDI
I.B19.EGDI.EP.26	Energy Probe Interrogatory	EGDI
I.B20.EGDI.CCC.28	CCC Interrogatory	EGDI
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I.C21.EGDI.VECC.7 and 8	VECC Interrogatories	EGDI
I.C23.EGDI.APPrO.1 to 4	APPrO Interrogatories	EGDI
I.C23.EGDI.CME.11	CME Interrogatory	EGDI
I.C23.EGDI.VECC.6, 9 and 10	VECC Interrogatories	EGDI
I.C24.EGDI.EP.27 to 29	Energy Probe Interrogatories	EGDI
I.C24.EGDI.VECC.16	VECC Interrogatories	EGDI
I.C25.EGDI.EP.30 to 33	Energy Probe Interrogatories	EGDI
I.C25.EGDI.VECC.11 to 14	VECC Interrogatories	EGDI
I.C26.EGDI.APPrO.5	APPrO Interrogatory	EGDI

EXHIBIT LIST

I – INTERROGATORIES AND RESPONSES

Exhibit	Contents	Witness(es)
I.C29.EGDI.Staff.68	Board Staff Interrogatory	EGDI
I.C30.EGDI.APPrO.6 to 14	APPrO Interrogatories	EGDI
I.C30.EGDI.CCC.29	CCC Interrogatory	EGDI
I.C30.EGDI.CME.15	CME Interrogatory	EGDI
I.C30.EGDI.OAPPA.5	OAPPA Interrogatory	EGDI
I.C31.EGDI.CME.16	CME Interrogatory	EGDI

Issue D

I.D33.EGDI.Staff.69	Board Staff Interrogatory	EGDI
I.D33.EGDI.CCC.30	CCC Interrogatory	EGDI
I.D33.EGDI.EP.34 and 35	Energy Probe Interrogatories	EGDI

Issue E

I.E35.EGDI.CME.7	CME Interrogatory	EGDI
I.E35.EGDI.SEC.119	SEC Interrogatory	EGDI
I.E35.EGDI.VECC.19	VECC Interrogatory	EGDI
I.E36.EGDI.Staff.70	Board Staff Interrogatory	EGDI
I.E36.EGDI.CME.12	CME Interrogatory	EGDI

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I – INTERROGATORIES AND RESPONSES

Exhibit	Contents	Witness(es)
I.E36.EGDI.EP.36	Energy Probe Interrogatory	EGDI
I.E39.EGDI.Staff.71 to 73	Board Staff Interrogatories	EGDI
I.E39.EGDI.FRPO.17 to 19	FRPO Interrogatories	EGDI
I.E39.EGDI.SEC.120 to 131	SEC Interrogatories	EGDI
I.E40.EGDI.Staff.74 to 97	Board Staff Interrogatories	EGDI
I.E42.EGDI.APPrO.15	APPrO Interrogatory	EGDI
I.E42.EGDI.CME.17 to 19	CME Interrogatories	EGDI
I.E42.EGDI.OAPPA.6 and 7	OAPPA Interrogatories	EGDI
I.E43.EGDI.APPrO.16	APPrO Interrogatory	EGDI
I.E43.EGDI.CCC.31	CCC Interrogatory	EGDI
I.E43.EGDI.OAPPA.8 and 9	OAPPA Interrogatories	EGDI
I.E44.EGDI.APPrO.17	APPrO Interrogatory	EGDI
I.E45.EGDI.APPrO.32 and 33	CCC Interrogatories	EGDI
I.E46.EGDI.SEC.132 to 134	SEC Interrogatories	EGDI
I.E48.EGDI.SEC.135 to 150	SEC Interrogatories	EGDI

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L – INTERVENOR EVIDENCE

Exhibit	Tab	Schedule	Contents	Witness(es)
Submissions on Preliminary Issue				
			EGDI submission – July 25, August 22 and September 4, 2013	
			Board Submission – September 4, 2013	
			BOMA Submission – September 4, 2013	
			CME Submission – September 4, 2013	
			CCC Submission – August 22, 2013	
			Energy Probe Submission – September 4, 2013	
			SEC Submission – July 20 and August 7, 2013	
			VECC Submission – August 20, 2013	
L	1	1	PEG Report – Revised April 27, 2012	
		2	PEG Report – October 2013	

EXHIBIT LIST

N – SETTLEMENT PROPOSAL

Exhibit	Tab	Schedule	Contents	Witness(es)
N1	1	1		
		2	Settlement Agreement – Aspects of Enbridge Gas Distribution 2014 Gas Supply Plan – October 29, 2013	

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

APPLICATION

1. The Applicant, Enbridge Gas Distribution (Enbridge), is an Ontario corporation with its head office in Toronto, Ontario. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. Enbridge hereby applies to the Ontario Energy Board (the Board), pursuant to section 36 of the *Ontario Energy Board Act, 1998*, as amended (the Act), for an Order or Orders approving or fixing rates for the sale, distribution, transmission and storage of gas as of January 1, 2014.

3. Enbridge seeks approval of rates for a five year period commencing January 1, 2014 based on an Incentive Regulation (IR) methodology that includes some or all of the following features:

(a) the determination of allowed distribution revenue (Allowed Revenue) for each year of the term of the proposed IR plan in accordance with the evidence filed in support of this Application;

(b) an adjustment process, in advance of each of the years 2015, 2016 and 2018 to adjust Allowed Revenue for each respective year, based on updated volumes and gas costs and amounts related to pension, Demand Side Management and customer care costs;

(c) an adjustment process, in advance of the year 2017, to adjust Allowed Revenues for 2017 based on updated volumes, gas costs and amounts related to pension, Demand Side Management and customer care costs, and to adjust Allowed Revenues for both 2017 and 2018 based on updated forecasts of capital spending, cost of capital, taxes and depreciation;

(d) deferral and variance accounts, as more particularly set out in Appendix “A” to this Application;

(e) a Z-factor pursuant to which Enbridge may apply to the Board for recovery of unexpected costs that are outside of Allowed Revenue in any year of the IR period;

(f) an Earnings Sharing Mechanism that will be triggered following any year of the IR term during which Enbridge’s Return on Equity (ROE) determined on the basis of weather-normalized earnings exceeds the ROE calculated annually in accordance with the Board’s ROE formula by more than 100 basis points;

(g) an Off Ramp that will be triggered following any year of the IR term during which Enbridge's ROE determined on the basis of weather-normalized earnings varies by 300 basis points or more above or below the ROE calculated annually in accordance with the Board's ROE formula; and

(h) a Sustainable Efficiency Incentive Mechanism pursuant to which Enbridge may earn incentives for introducing efficiencies that will continue beyond the end of the IR term.

4. Enbridge also seeks approval of a new degree day methodology to determine heating degree day forecasts for its Central Delivery Area to apply during the IR term; a proposed change in depreciation rates to reduce the annual amount for future site restoration costs; a proposed rate rider to return to ratepayers over a five year period an amount previously collected in depreciation rates for site restoration costs; and a proposed Rate 332 for transportation service to be provided to TransCanada PipeLines Limited.

5. Enbridge therefore applies to the Board for such final, interim or other Orders and accounting orders as may be necessary or appropriate for the following purposes:

(a) to give effect to the proposed IR methodology, as summarized in paragraph 3, above;

(b) to fix or approve rates commencing on January 1, 2014 based on the IR methodology summarized in paragraph 3, above, and the evidence filed in support of this Application;

(c) to establish deferral and variance accounts for 2014 to 2018 in accordance with the list of proposed accounts set out in evidence filed at Exhibit D, in Tab 8;

(d) to approve the new heating degree day forecast methodology proposed by Enbridge for its Central Delivery Area;

(e) to approve the proposed treatment of site restoration costs, including the five-year rate rider proposed by Enbridge;

(f) to approve the proposed Rate 332;

(g) in all other respects to give effect to the proposals described in the evidence filed in support of this Application and such modifications to those proposals as may be brought forward in this proceeding by Enbridge and deemed appropriate by the Board.

6. In the event that Enbridge's application is approved by the Board, the average rate decrease for residential customers for 2014 will be approximately 0.7%, or about $4, on a T-service basis (that is, excluding Gas Supply Charges). The estimated

average rate increase for residential customers for 2015 will be approximately 2.1%, or about $12, on a T-service basis, and the average rate increase for residential customers for 2016 will be approximately 4.6%, or about $27, on the same basis.

7. Subject to the Board's Approval of Enbridge's proposed rebate to the ratepayer related to Site Restoration Charges previously collected, the impact on a total bill basis for an average residential customer would be a reduction of $30 on an annual basis in the 2014 Fiscal Year

7. Enbridge further applies to the Board, pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure*, for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

8. Enbridge requests that a copy of every document filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

<u>The Applicant</u>:

Mr. Norm Ryckman
Director, Regulatory Affairs
Enbridge Gas Distribution, Inc.

Address for personal service:	500 Consumers Road Willowdale, Ontario. M2J 1P8
Mailing address:	P.O. Box 650 Scarborough, Ontario. M2J 1P8
Telephone:	416-495-5499 or 1-888-659-0685
Fax:	416-495-6072
Email:	EGDRegulatoryProceedings@enbridge.com

The Applicant's counsel:

Mr. Fred D. Cass
Aird & Berlis LLP

Address for personal service:	Brookfield Place, P. O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario. M5J 2T9
Telephone:	416-865-7742
Fax:	416-863-1515
Email:	fcass@airdberlis.com

DATED at Toronto, Ontario July 3, 2013.

ENBRIDGE GAS DISTRIBUTION INC.

Per: [original signed]
Mr. Norm Ryckman

APPROVALS REQUESTED

1. The Company has filed evidence in support of its proposal for a Customized Incentive Regulation ("Customized IR") plan for the determination of the Allowed Revenue amounts for the five year term from 2014 to 2018 and to the setting of final rates for the 2014 Fiscal Year. The Company's Customized IR plan will see final rates set for the 2015 to 2018 Fiscal Years in annual Rate Adjustment proceedings. The 2017 Rate Adjustment proceeding will include an update of the Approved Revenue amounts for 2017 and 2018. The Rate Adjustment proceedings for 2015 to 2018 will use the Approved Revenue amounts for each of those years, along with updated forecasts of a limited group of items including volumes and gas costs and amounts related to pension, Demand Side Management and customer care costs, in order to set final rates for each Fiscal Year.

2. The evidence describing the proposed Customized IR plan is located at Exhibit A2, Tab 1, Schedule 1. This overview evidence provides parties with a summary of the steps taken in the development of the Customized IR plan, the components and parameters of the proposed plan, along with the objectives, key issues, challenges and alternatives that were considered during its design and development.

3. The Company will be asking for the Board's Approval of its proposed Customized IR plan, including the following elements:
   a) Approval of the methodology to be used in the determination of Allowed Revenue amounts for the 2014 through 2018 Fiscal Years;
   b) Approval of the process to set final rates for the 2014 Fiscal Year, as set out at Exhibits F, G and H;
   c) Approval for the implementation of the proposed rates as filed in this Application at Exhibit H, effective January 1, 2014;

d) Approval of the process within the 2017 Rate Adjustment proceeding to update the preliminary Allowed Revenue amounts for 2017 and 2018, as outlined in evidence at Exhibit A2, Tab 3, Schedule 2; and

e) Approval of the proposed annual Rate Adjustment application, timing and process to be undertaken for the determination of final rates in the 2015, 2016, 2017 and 2018 Fiscal Years as outlined in evidence at Exhibit A2, Tab 3, Schedule 1.

4. The Company will be asking for the Board's Approval of additional components of its proposed Customized IR plan, including the following:

a) Approval of the proposed cost of capital parameters (ROE and debt rates) for the 2014 to 2018 Customized IR term, as set out at Exhibits A2, Tab 5, Schedule 1, Exhibit E1, Tab 1, Schedule 1, and Exhibit E2, Tab 1, Schedule 1;

b) Approval of the proposed Z Factor mechanism at Exhibit A2, Tab 4, Schedule 1;

c) Approval of the proposed Off-Ramp condition found in evidence at Exhibit A2, Tab 6, Schedule 1;

d) Approval of the inclusion of an Earnings Sharing Mechanism ("ESM") as described in evidence at Exhibit A2, Tab 7, Schedule 1;

e) Approval of the Company's proposed deferral ("DA") and variance accounts ("VA"), the evidence for which can be found in the series of exhibits at filed Exhibit D1, Tab 8;

f) Approval of the Company's proposed Performance Measurement mechanisms to be used during and following the IR term, the evidence for which can be found at Exhibit A2, Tab 11, Schedule 2; and

Approval of the Company's proposed Sustainable Efficiency Incentive Mechanism ("SEIM") as described in evidence at Exhibit A2, Tab 11, Schedule 3.

5. Inherent in the request to Approve the proposed Customized IR plan, as well as the 2014 to 2018 Allowed Revenue amounts and 2014 final rates, are all of the underlying outcomes, methods, models and processes used in the determination of those individual elements which underpin the mechanics and mathematics of the Customized IR plan, Allowed Revenue determination, cost allocation, rate design and rate adjustment(s).

6. The Company will be asking for the Board's Approval of the following outputs of the Customized IR plan:
   a) The Allowed Revenue amounts for each of the five years (2014 through 2018) of the proposed plan, with the 2017 and 2018 Allowed Revenue amounts being set on a preliminary basis, to be updated within the 2017 Rate Adjustment proceeding;
   b) The final rates for the 2014 Fiscal Year (as set out in the "G" and "H" series of Cost Allocation and Rate design exhibits), determined using the Allowed Revenue amount for 2014 as applied to forecast volumes and revenues, which are described in the evidence filed in this Application; and
   c) The Approval for the use of the Approved Revenue amounts for the 2015 to 2018 Fiscal Years within the annual Rate Adjustment applications for each Fiscal Year[1].

7. The Company will be asking for the Board's Approval of the changes to certain forecasting and other methodologies previously reviewed and approved, including the following:
   a) A change in the methodology for the determination of a heating degree day ("HDD") forecast for the "Central Delivery Area" to its proposed 50/50 Method

[1] The Company is proposing that the volume, revenue related to distribution volume and gas cost working cash forecast will be a component of the annual rate application process. Please refer to Exhibit A2-3-1.

which is a blend based upon 50% of the 20-Year with Trend and 50% of the 10-Year Moving Average methodologies. The evidence for this proposal is filed at Exhibit C2-1-2;

b) A proposal to reduce depreciation rates in 2014 and subsequent years, in order to reduce the annual amount of future site restoration costs ("SRC"), which is also referred to as asset retirement obligation ("ARO"), collected in depreciation expense. The evidence for this proposal is filed at Exhibit D1, Tab 5, Schedule 1; and

c) A proposal to return to ratepayers over a five year period, an amount of approximately $292 million in SRC/ARO previously collected in depreciation rates but now determined to be in excess of that required in future periods as a result of a change to the methodology to be used for the determination of future SRC/ARO requirements. This proposal is a component of the evidence filed at Exhibit D1, Tab 5, Schedule 1.

d) A change in the structure of the Transactional Services deferral account ("TSDA") that would result due to the Company's proposal to withdraw the provision of a TS revenue guarantee in rates. This proposal is set out at Exhibit C1, Tab 3, Schedule 1.

8. The Company is also requesting Approval for certain rate-related items, including:

a) A proposed Rate 332 related to transportation service to be provided to TransCanada PipeLines Limited;

b) Proposed changes to certain rates (Rates 100 and 110) as set out at Exhibit H1, Tab 1, Schedule 2; and

c) Proposed changes included in the Rate Handbook that is found in the evidence filed at Exhibits H2, Tab 6, Schedule 1.

9. As set out at Exhibit A2, Tab 3, Schedule 1, the Company retains the right to apply to the Board, with supporting evidence, for changes to energy and non-energy rates and services during the IR term.

10. Other notable factors and items to be considered within this Application include the following:
    a) The Company has filed its current Conditions of Service at Exhibit A1, Tab 5, Schedule 1 but is not requesting any changes or review in this proceeding. This material is filed for reference only in this application;
    b) The Company has filed its current Schedule of Service Charges at Exhibit A1, Tab 5, Schedule 2 but is not requesting any changes or review in this proceeding. This material is filed for reference only in this application and can also be found in the Rate Handbook, as Rider G;
    c) The Company has filed its New Community Proposal in evidence at Exhibit B1, Tab 3, Schedule 1 and has indicated that it may proceed with an Application during the IR term related to the connection of new communities, which may seek approval of new tools and mechanisms to address the financial feasibility of such projects; and
    d) The Company has filed a separate application for the continuation of its Open Bill Access program (EB-2013-0099). The Company expects that the Decision(s) in that proceeding will be 'folded into' this rate proceeding.

DRAFT ISSUES LIST

A. The Customized IR Plan

1. Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate ?

    a. Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements ?

    b. Does Enbridge's Customized IR plan ensure appropriate quality of service for customers ?

    c. Does Enbridge's IR plan create an environment that is conducive to investment, to the benefit of customers and shareholders ?

2. Is the methodology within Enbridge's Customized IR plan for determining annual Allowed Revenue amounts appropriate ?

3. Is the methodology within Enbridge's Customized IR plan for updating the 2017 and 2018 Annual Revenue amounts within the 2016 Rate Adjustment proceeding appropriate ?

4. Is the methodology within Enbridge's Customized IR plan for determining final rates for 2014 appropriate ?

5. Is the methodology within Enbridge's Customized IR plan for setting final rates for 2015 and 2018 through annual Rate Adjustment proceedings appropriate ?

6. Are the cost of capital parameters for 2014 to 2018 (ROE, debt rates) within Enbridge's Customized IR plan appropriate ?

7. Are the following components within Enbridge's Customized IR plan appropriate?

    a. Z Factor mechanism

    b. Off-ramp condition

    c. Earnings Sharing Mechanism

d. Treatment of Cost of Capital

e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)

f. Sustainable Efficiency Incentive Mechanism

g. Annual reporting requirements

h. Rebasing proposal

8. Is the proposal to continue Enbridge's current deferral and variance accounts through the IR term appropriate ?

9. Is the proposal for the creation of the following new deferral and variance accounts appropriate ?

   a. Greater Toronto Area Project Variance Account ("GTAPVA")

   b. Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA")

   c. Customer Care Services Procurement Deferral Account ("CCSPDA")

   d. Greenhouse Gas Emission Impact Deferral account ("GGEIDA")

10. Is the proposal to permit Enbridge to apply for changes in rate design and new energy and non-energy services during the IR term appropriate ?

B. Allowed Revenue

11. Is the Allowed Revenue amount for 2014 calculated properly ?

   a. Is the depreciation amount, including the impacts of the 2014 capital budget, within the 2014 Allowed Revenue appropriate ?

   b. Is the operating costs amount within the 2014 Allowed Revenue appropriate ?

   c. Is the amount for income and municipal taxes within the 2014 Allowed Revenue appropriate ?

d. Is the cost of capital amount within the 2014 Allowed Revenue appropriate?

e. Is the Other Revenues amount within the 2014 Allowed Revenue appropriate ?

12. Is the Allowed Revenue amount for 2015 calculated properly ?

a. Is the depreciation amount, including the impacts of the 2014 and 2015 capital budgets, within the 2015 Allowed Revenue appropriate ?

b. Is the operating costs amount within the 2015 Allowed Revenue appropriate ?

c. Is the amount for income and municipal taxes within the 2015 Allowed Revenue appropriate ?

d. Is the cost of capital amount within the 2015 Allowed Revenue appropriate?

e. Is the Other Revenues amount within the 2015 Allowed Revenue appropriate ?

13. Is the Allowed Revenue amount for 2016 calculated properly ?

a. Is the depreciation amount, including the impacts of the 2014 to 2016 capital budgets, within the 2016 Allowed Revenue appropriate ?

b. Is the operating costs amount within the 2016 Allowed Revenue appropriate ?

c. Is the amount for income and municipal taxes within the 2016 Allowed Revenue appropriate ?

d. Is the cost of capital amount within the 2016 Allowed Revenue appropriate?

e. Is the Other Revenues amount within the 2016 Allowed Revenue appropriate ?

14. Is the preliminary Allowed Revenue amount for 2017 calculated properly ?

    a. Is the preliminary depreciation amount within the 2017 Allowed Revenue appropriate ?

    b. Is the operating costs amount within the 2017 Allowed Revenue appropriate ?

    c. Is the preliminary amount for income and municipal taxes within the 2017 Allowed Revenue appropriate ?

    d. Is the preliminary cost of capital amount within the 2017 Allowed Revenue appropriate ?

    e. Is the Other Revenues amount within the 2017 Allowed Revenue appropriate ?

15. Is preliminary Allowed Revenue amount for 2018 calculated properly ?

    a. Is the preliminary depreciation amount within the 2018 Allowed Revenue appropriate ?

    b. Is the operating costs amount within the 2018 Allowed Revenue appropriate ?

    c. Is the preliminary amount for income and municipal taxes within the 2018 Allowed Revenue appropriate ?

    d. Is the preliminary cost of capital amount within the 2018 Allowed Revenue appropriate ?

    e. Is the Other Revenues amount within the 2018 Allowed Revenue appropriate ?

C. <u>2014 Rates</u>

16. Is the 2014 forecast of Customer Additions appropriate?

17. Is the 2014 revenue forecast appropriate ?

18. Is the 2014 gas volume forecast appropriate?

19. Is the 2014 degree day forecast for each of the Company's delivery areas (EDA, CDA and Niagara) appropriate?

20. Is the 2014 Average Use forecast appropriate?

21. Is the 2014 level of Unaccounted For ("UAF") volume appropriate?

22. Is Enbridge's forecast of gas, transportation and storage costs for 2014 appropriate?

23. Is the Allowed Revenue deficiency or sufficiency for the 2014 Fiscal Year calculated correctly?

24. Is the overall change in Allowed Revenue reasonable given the impact on consumers?

25. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

26. Are the rates proposed for implementation effective January 1, 2014 and appearing in Exhibit H, just and reasonable?

27. How should the Board implement the rates relevant to this proceeding?

D. Other

28. Is the proposal for the treatment and sharing of Transactional Services ("TS") revenues appropriate?

29. Is the proposal to introduce a new Hybrid 50/50 forecasting methodology for the determination of a heating degree day (“HDD”) forecast for the Company’s “Central Delivery Area” appropriate?

30. Is the proposed implementation, treatment and cost recovery related to the change in the peak gas day design criteria, approved by the Board in the 2013 rate application (EB-2011-0354), appropriate?

31. Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation (“SRC/ARO”) collected, appropriate?

32. Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

33. Is the proposal for the Open Bill Access Program appropriate?

34. Are the proposed changes to rate 100 and rate 110 appropriate?

35. Are the proposed changes to the Rate Handbook appropriate?

36. Is Enbridge’s rate design for the proposed TCPL Transportation rate appropriate?

37. Is the rate of return on the Natural Gas Vehicle (“NGV”) program appropriate?

38. Has Enbridge responded appropriately to all relevant Board directions from previous proceedings?

39. Are Enbridge's economic and business planning assumptions appropriate?

CONDITIONS OF SERVICE

1. The Ontario Energy Board ("Board") issued amendments to the Gas Distribution Access Rule ("GDAR") on October 14, 2011 to have rate-regulated gas distributors include customer service standards and practices in their Customer Service Policies. On September 6, 2012, the Board issued further amendments to GDAR to have gas distributors include low-income specific customer service standards and practices in their Customer Service Policies. As per section 8.2.1 of GDAR, the Company published its amended Conditions of Service which describes Enbridge's operating practices and policies with respect to gas distribution services and customer service on January 1, 2013. The Conditions of Service, as published on the Company's website at enbridgegas.com/Conditions of Service, are presented in Appendix A.

2. In an effort to improve customer satisfaction and enhance customer's experience with Enbridge, the Company is currently undertaking a Bill Presentment project to enhance the way information is provided on the bill. The goal of this initiative is to improve customers understanding of the information provided. As a part of this initiative, the Company intends to revisit the description of its Late Payment Penalty ("LPP") presented on the bill to make it more customer friendly and easier to understand. Any changes to the description of LPP will also be updated in the Conditions of Service, if required, at that time.

Witnesses: T. Ferguson
S. McGill

ENBRIDGE GAS DISTRIBUTION INC.

CONDITIONS OF SERVICE

JANUARY 1, 2013

Revision History

Version #	Date of Revision	Description *(e.g. "First Draft", "Final Approval Copy")*
1.0		First Draft
2.0	2011/12/30	Section 6.1 Setting Up an Enbridge Account to include the requirement to provide Enbridge with 3 days advance notice of a move. If notification is not received Enbridge will only retroactively adjust the account for a maximum of 30 days from the date notification is received. This will be implemented starting Jan 1 2012. Section 6.3 Security Deposits to revise the good payment history period for return of a security deposit from 24 to 12 months. This will be effective from Jan 2012. Section 6.5 Correction of Billing errors to restrict the period of correction for over or under billing to two years. This will be implemented starting Jan 1 2012. Section 6.9 Management of Customer Accounts originally stated "In a landlord tenant situation Enbridge will follow directions recorded on the account when gas service was initially established". The phrase "when gas service was initially established" has been removed to allow for updated directions to be received from a Landlord.
3.0	2012/03/30	Section 6 now gives a short description of accounts that are classified as Commercial for reference Section 6.1 Setting Up an Enbridge Account removed reference to when these conditions remain in effect Section 6.2 Meter Reading informs customers that they must give access to Enbridge to read the meter at least one per 12 months Section 6.6.3 Discontinuance of Service for Non Payment to inform customers that the Disconnection notice now includes the dates between which the gas service can be disconnected and payment options for avoiding disconnection. This was effective from Jan 2012 Section 6.7 Arrears Management Programs to inform customers of the cancellation of installment plan letter. This was effective from Jan 2012. Also to advise customers working with a Social Assistance agency that they will be give 21 days to secure emergency financial assistance before additional Collections action will be taken. This was effective from Jan 2012. Section 6.9 Management of Customer Accounts to inform Landlords of the new process of recording Landlord directions for the properties they own/manage. This was effective March 2012.
4.0	2013/1/1	Section 6 now includes information for Low Income Customers

Contents

Preface

As Canada's largest natural gas distribution company, Enbridge Gas Distribution Inc. ("Enbridge") has been providing natural gas services in a safe and reliable manner for more than 160 years, and currently provides service to approximately 1.9 million homes and businesses.

These Conditions of Service describe in summary form Enbridge's operating practices and policies, and are provided as part of our commitment to providing our customers with safe and reliable gas services.

We reserve the right to modify the contents of the Conditions of Service at any time. These Conditions of Service are meant as guidelines and do not supersede any terms and conditions set out in Enbridge's Rate Handbook, or agreed to in our contracts for gas supply with you.

1. Enbridge Franchise Area and Gas Distribution Services

The following is a current list of cities and towns to which Enbridge provides distribution services.

Eastern Region

Admaston	Hawkesbury	Ottawa
Alfred & Plantagenet	Horton	Pembroke
Arnprior	Laurentian Hills	Perth
Beckwith	Laurentian Valley	Petawawa
Brockville	Leeds and Grenville	Renfrew
Carleton Place	McNab-Braeside	Rideau Lakes
Casselman	Merrickville-Wolford	Russell
Champlain	Mississippi Mills	Smiths Falls
Clarence-Rockland	Montague	South Glengarry
Deep River	North Glengarry	Tay Valley
Drummond-North Elmsley	North Grenville	The Nation
Elizabethtown-Kitley	North Stormont	Whitewater Region

Central Region

Adjala	East Luther Grand Valley	Penetanguishene
Ajax	Erin	Peterborough
Amaranth	Essa	Pickering
Asphodel-Norwood	Georgina	Richmond Hill
Athens	Grey Highlands	Scugog
Aurora	Havelock Belmont Methuen	Severn
Barrie	Innisfil	Shelburne
Bradford-West Gwillimbury	Kawartha Lakes	Smith-Ennismore-Lakefield
Brampton	King	Southgate
Brighton	Markham	Springwater
Brock	Melancthon	Tay
Caledon	Midland	Tiny
Cavan Monaghan	Mississauga	Toronto
Clarington	Mono	Trent Hills
Clearview	Mulmur	Uxbridge
Collingwood	New Tecumseh	Vaughan
Douro-Dummer	Newmarket	Wasaga Beach
Dufferin	Orangeville	Wellington
Durham	Oshawa	Whitby
East Garafraxa	Otonabee S- Monaghan	Whitchurch
East Gwillimbury		

Niagara Region

Fort Erie	Niagara-on-the-Lake	Thorold
Grimsby	Pelham	Wainfleet
Lincoln	Port Colburne	Welland
Niagara Falls	St. Catharines	West Lincoln

2. Gas Distribution Services

2.1. Gas Supply and Delivery

Gas will be delivered and/or supplied to our customers within our franchise area subject to these Conditions of Service and to the provisions of Enbridge's rate schedules, under the following circumstances:

- there is sufficient supply of gas;
- there is sufficient capacity in Enbridge's distribution system; and,
- the supplying and/or delivering of gas is economically feasible.

2.2. Gas supply and/or delivery under more than one rate schedule

Gas may be supplied and/or delivered under more than one rate:

- Provided the customer meets all the applicability requirements of each rate schedule as approved by the Ontario Energy Board. Gas supplied and/or delivered under each rate schedule will normally be metered separately but may be taken through one meter provided:
    - Enbridge and the customer agree in writing upon a formula for determining the supply and/or delivery service that the customer will purchase under each rate schedule.

2.3. Interruptions in Gas Distribution and/or Supply

Customers may be required to curtail or discontinue the use of gas if the supply of gas is jeopardized by any of the following:

- in the event of actual or threatened shortage of gas due to circumstances beyond the control of Enbridge;
- when curtailment or restriction is ordered by any government or agency having jurisdiction; or
- for any force majeure event (described below).

Enbridge shall not be liable for any loss of production, nor for any damages whatsoever due to such curtailment or discontinuance. Enbridge may also interrupt service from time to time for repair and maintenance of facilities. Except in the case of an emergency, Enbridge will provide affected customers with reasonable notice of such interruption.

2.4. Force Majeure

Customers of Enbridge shall not have any claim against Enbridge for damages sustained as a result of the interruption or cessation of gas deliveries caused by force majeure which include:

- acts of God, the elements;
- labour disputes, strikes, lockouts;
- fires, accidents;
- the breakage or repair of pipelines or machinery;
- curtailment by an upstream gas transporter;
- depletion or shortage of gas supply;
- order of any legislative body or duly constituted authority; or
- any other cause or contingencies beyond the control of Enbridge.

3. Rate Schedule

3.1. Changes in Rate Schedules

In the event the Ontario Energy Board amends the rate schedules of Enbridge, the amended price or amended terms and conditions shall apply to services provided under the rate schedules after the effective date established by the Ontario Energy Board.

4. Initiation of Service

4.1. Main Extensions

Enbridge will extend its gas main within its franchise area to serve new customers when it is feasible, in accordance with Enbridge's feasibility policy and procedures, to do so. Enbridge will look at the following when determining feasibility:

- the number of potential new customers within the next five years;
- the amount of natural gas to be used; and,
- the cost of extending the gas main.

If the cost of the extension is not economically feasible, the applicant/s will be required to pay a contribution in aid of construction. Enbridge will determine the contribution amount and communication will be provided to the applicant/s in writing.

4.2. Service Installations

Enbridge reserves the right to designate the location at which the service will enter a building. The normal point of entry will be through the wall nearest to the gas supply. Where no additional cost is involved, the service may be installed to accommodate requirements of the applicant for service in Enbridge's discretion.

For residential service, Enbridge will usually install a service at no charge to the applicant, provided the service installed is 20 metres in length measured from the property line to a point of delivery up to 2 metres beyond the front building wall. For residential and non residential service, the cost of the service in excess of the cost of a normal residential service of 20 metres in length, and any length exceeding 2 metres beyond the front building wall, may be charged to the applicant.

In the event the customer does not use natural gas within six months of installation of a new gas service, the customer will pay Enbridge's costs for such installation.

Where an applicant for gas service requests an installation on property that is not owned by the customer such as road allowance, municipal or neighboring property, land rights (in the form of an easement) from the property owner will be required for the installation and maintenance of all necessary gas lines and equipment.

Enbridge will try to restore property to the approximate condition in which it was found before starting our operations. This includes property that is excavated or may be disrupted during laying, constructing, repairing or removing our facilities.

4.3. Location of Meter and Service Regulators

Enbridge shall supply each customer with a meter of a size and type that will adequately measure the gas supplied. Enbridge shall:

4.3.1. Make every effort to install meters and service regulators so as to be at all times accessible for inspection, reading, testing, maintaining and exchanging.

4.3.2. Not install meters in locations prohibited by law. The following locations are specifically prohibited:
- under combustible stairways;
- unventilated areas;
- inaccessible areas; or,
- within 90 cm (3 feet) of a source of ignition.

4.3.3. Install all meters outside the building to which gas is supplied except in rare circumstances where it is not practical.

4.3.4. Provide protection where outside meters and regulators are installed in locations that do not afford reasonable protection from damage.

Anyone who is not an authorized agent of Enbridge shall not be permitted to connect or disconnect our meters or regulators, nor shall any piping be connected to or disconnected from Enbridge's facilities except by representatives of Enbridge.

Customers are responsible, subject to the provisions of paragraph 4.3.4, for protecting all metering and regulating equipment necessary for the supply of gas and for keeping it accessible at all times.

4.4. Alterations

Alterations or service relocation requests will be dealt with as follows:

- The cost of work done to relocate existing equipment solely for the convenience of the customer will be charged to the customer.
- The undepreciated cost of any equipment abandoned as a result of relocation for the customer's convenience, or replacing equipment to increase their capacity to accommodate a customer's increased requirements, may be charged to the customer.

4.5. Customer Responsibilities regarding Building Piping Appliances & Equipment

As an applicant for service, a customer shall:

- at their own expense install, all piping, controls, safety devices, and other attachments necessary from the meter to the equipment or appliances served;
- ensure the building piping, appliances, and equipment are installed in accordance with regulations made under the authority of statutes passed by the Province of Ontario establishing the requirements for the installations of such facilities; and,
- be responsible for maintaining all building piping, appliances and equipment in a good and safe condition. Such maintenance will be at the customer's own expense.

If there is a leakage or escape of gas on a customer's premise, the customer is required to notify Enbridge immediately by calling our emergency number at 1-866-763-5427.

Enbridge shall not be liable to the customer for any damages. The customer shall indemnify Enbridge from and against all loss, costs, damages, injury, or expense associated with any injury or damage to persons or property arising, either directly or indirectly, from or incidental to the escape of gas or products of combustion of gas from building piping, venting systems or appliances on the customer's side of the point of delivery.

For the purpose of inspecting or repairing or of altering or disconnecting any service pipe within or outside the building, the customer shall ensure that free access is permitted to Enbridge at all reasonable times, and upon reasonable notice given and request made, to all parts of every building or other premises to which gas is supplied.

4.6. Inspections of New Installations

All inspections shall conform to the Technical Standards and Safety Act and regulations. Also, all new installations of supply piping, gas appliances and installations will be inspected prior to gas being introduced to a building in accordance with the Technical Standards and Safety Act and regulations. If the inspection reveals that repairs or adjustments are required, the customer will be advised and repairs or adjustments will need to be corrected prior to the gas being turned on.

5. Maintenance of Service

5.1. Turning Off and Turning on Gas Supply

In an emergency, the gas supply to appliances may be turned off in the interest of safety. Only a qualified person holding an appropriate certificate from the regulatory authority having jurisdiction may turn on the supply of gas to appliances which have been turned off.

Except in the case of a notification of a hazard, the turning on and off of the gas supply for purposes of installing, servicing, removing or repairing gas appliances may only be done by a person certified to perform this work by the regulatory authority having jurisdiction.

5.2. Meter Exchange and Testing

5.2.1. Meter Exchange

Under Government of Canada regulations (Section 12 of the Electricity and Gas Inspection Act), Enbridge is required to periodically exchange gas meters for government inspection.

To complete the meter exchange, we will shut off the gas supply to your existing meter, replace it with a new meter and then relight and inspect all of your natural gas equipment.
There is no charge for this service. If we are required to exchange your meter we will contact you via letter or telephone. Please call the number provided at the time of contact to make an appointment. The inspector who comes to your property will carry valid Enbridge photo ID and you may ask to see it before providing access.

5.2.2. Meter Testing

Should a meter fail to register the amount of gas used, consumption shall be estimated by Enbridge and supply and/or delivery charges shall be paid for by the customer in accordance with such estimate.

Should a customer dispute the accuracy of a meter, an application for a Government Inspection of the meter in accordance with the Electricity and Gas Inspection Act may be made. If, after the test, the meter is found to register with an error greater than that permitted by regulations, such error shall be held to have existed for a period of three months or from the date on which the meter was last sealed if the said sealing took place within three calendar months of the request. In the event of the meter being more than three months past due for re-verification, Enbridge or the customer, as the case may be, is entitled to the amount represented by the full error of the meter from the date on which it should have been re-verified. All costs involved in effecting this test shall be borne by the party against whom the decision is given.

In the event of an erroneous connection or incorrect use of an apparatus, the error shall be deemed to have existed from the time of connection.

In the event it can be, through records, determined when an error occurred, the bill will be retroactive to that time.

6. Customer Service for Residential and Low-Income Customers

For the purposes of this section, “customer” means a residential customer (referred to as “you” in this section).

Any property from which a business is being operated is classed as a Commercial account and Section 6 would not apply.

The Low-Income Energy Assistance Program (LEAP) developed by the Ontario Energy Board is a year-round program to assist low-income customers with their bill payments and natural gas costs.

An “Eligible Low-income customer” means a residential customer who has a pre-tax household income at or below the most recent pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service Agency or Government Agency; or has been qualified for Emergency Financial Assistance.

“Emergency Financial Assistance” means any Board-approved emergency financial assistance, or other financial assistance made available by a distributor, to eligible low-income customers.

For more information on the LEAP program please visit www.enbridgegas.com/leap

6.1. Setting up an Enbridge Account

Whether you are a first time customer to Enbridge or moving from an existing Enbridge account, you should notify us before taking possession of a new home. Enbridge requires at least 3 business days (including Saturdays) advance notice of a move. If advance notice is not given Enbridge will only retroactively adjust the account for a maximum of 30 days from the date notification is received.

On our website you will find information on how to submit a “First Time Customer” form or a Move request or you can call the Enbridge Call Centre at 1-877-362-7434.

As an Enbridge customer you will be expected to comply with the terms and conditions for natural gas service and will be obliged to pay for all gas supplied and/or delivered to your premises.

6.2. Meter Reading

Enbridge reads your meter every other month and will estimate your consumption based on your historical gas usage in between readings. Customers must provide access to the Company or its' agent for meter reading purposes at least once every twelve (12) months. If Enbridge's representative is unable to read the meter, a bill will be issued based on an estimated reading. If Enbridge has been unable to read a meter during normal working hours, arrangements will be made to obtain a reading at the customer's convenience. You can also submit your own meter reading using the Submit Meter Reading Form on our website or alternatively, you can call the Enbridge Call Centre at 1-800-268-5442.

6.3. Security Deposits

Security deposits are collected to secure payment for future charges in the event of a customer not paying their bill. To protect against losses, Enbridge reserves the right to request a security deposit from its customers as a condition of supplying gas service. A security deposit may be required if you are a first time Enbridge customer, or if you have not been able to maintain a good payment history.

All new residential customers are subject to a security deposit, unless they meet one of the waiver criteria outlined below. If you are required to pay a security deposit an amount of $250.00 will be charged on your next gas bill. Payment of the security deposit is required by the Late Payment Effective Date on the bill.

Enbridge will waive your security deposit requirement if you meet any of the following criteria:

- If you have moved and your previous account is in good standing;
- If you choose to sign up for our Pre-Authorized Payment Plan;
- If you can provide a reference letter from another utility in Canada dated within the past 60 days; or
- If you are an eligible low-income customer (see section 6) and are moving residences, providing the following conditions are met:
    - You are enrolled in the budget billing plan
    - You do not have an account with a financial institution and
    - Your gas service has not been disconnected due to non-payment in the past two years.

Enbridge will review all security deposits on a monthly basis from the date the deposit is fully paid. If you have paid a security deposit, it will be refunded once you have demonstrated good payment history for a period of 12 months. Your security deposit will be returned with interest as a credit on your next gas bill. If you choose to have the amount refunded, you can call the Enbridge Call Centre at 1-877-362-7434 and a refund cheque will be issued.

Good payment history is maintained unless you have experienced any of the following:

- Receipt of a disconnection notice from Enbridge;
- A payment you provided to Enbridge has been returned for insufficient funds; or
- Your gas has been turned off due to non-payment.

Interest earned on your security deposit will be paid upon return of all or any part of the security deposit or at the time you close your account, whichever comes first. Simple interest will be earned on all security deposits except those held for a total of six months or less. The interest rate applicable to security deposits in any year will be established quarterly and will be based upon the Ontario Energy Board prescribed interest rates. Interest is calculated retroactively to the date the security deposit was received.

Security deposits are not to be considered as prepayments for future charges.

6.4. Bill Issuance and Payment

6.4.1. Your Monthly Bill

Enbridge charges you the following charges on a monthly basis:

- **Monthly Customer Charge**
  Enbridge has a minimum charge per gas meter to help recover a portion of the fixed costs that the company incurs to keep the system ready for customer use at all times. These fixed costs (such as 24-hour emergency service, meter reading, pipeline maintenance and customer support services) do not vary with the amount of gas used.

- **Transportation to Enbridge**
  This charge is for the cost of transporting natural gas to distribution facilities in Ontario, including tolls.

- **Delivery to You**
  Once natural gas is received by Enbridge, these are the costs to safely and reliably deliver natural gas to our customers.

- **Gas Supply Charge**
  The charge for natural gas itself varies with the amount of gas used by each of our customers. You can choose to have your gas supplied by Enbridge Gas Distribution or an independent marketer. The rates that Enbridge charges for gas used are regulated by the Ontario Energy Board.

There are other charges that may appear on your bill from time to time based on events that occur with your account. These include:

- **New Account Charge**
  If you open a new account with Enbridge, the first bill will include a one time service charge of $25.00, to help cover the costs of setting up the account, taking a meter reading and related work.

- **Late Payment Effective Date/Late Payment Charge**
  Enbridge charges are due when the bill is received, which is considered to be three days after the date the bill is rendered. Customers are provided a period of 17 days to make a payment before a Late Payment Charge is applied to their account.

  When payment in full of the Enbridge invoice is not received on or before the "Late Payment Effective Date" on the bill, a late payment charge will be incurred on the next bill. A charge of 1.5% per month (19.56% effectively per annum) on all of the unpaid charges, including all applicable federal and provincial taxes, will be applied to the account.

  Late payment charges are not applied to security deposits amounts owing.

- **Adjustments**
  Your bill may show adjustments to charges from time to time when there is a correction made on your account.

For more information on the charges that appear on your bill, visit the Understanding Your Bill section on our website.

6.4.2.Charges from Other Companies

The Enbridge Billing Service allows other energy companies to include their charges on the Enbridge bill. If you have purchased a product or service from a participating company, the charges would appear in the section called “Charges From Other Companies” on your Enbridge bill.

This service helps make paying bills more convenient for you. You receive one bill and make one monthly payment to Enbridge Gas Distribution. This service also helps to keep rates low by sharing costs with other billers.

6.4.3.Billing from a licensed energy marketer

If you buy your natural gas supply from a licensed energy broker, your gas supply charges, along with the name of the licensed energy broker will appear in the 'Charges For Gas' section of your Enbridge bill.

6.4.4.Billing Options

- **Paperless Billing**

Enbridge offers customers an environmentally friendly and secure bill delivery option in the form of a paperless bill. You can view and store up to 24 months of bills electronically through this service.

- **Budget Billing Plan**

The Enbridge Budget Billing Plan (BBP) is available to all residential gas heating customers at any time during the year and provides the convenience of paying equal amounts throughout the year and avoiding higher bills in winter months. Using your prior year’s gas usage, Enbridge forecasts the amount of gas you will use and applies the current gas price to determine your monthly BBP installment.
The BBP season runs from September to July each year. In July, Budget Billing Plans are reviewed and reconciled and customers are billed or credited a BBP Final Adjustment that represents the difference between the charges for gas actually used from the time you join the plan and the monthly BBP installments billed to date. In the month of August, you are billed for the actual gas used in the month. The new plan then starts again in September.

Should a credit balance result after the annual reconciliation, the amount will be credited to your account and will appear on your July bill. If you choose to have the amount refunded, you can call the Enbridge Call Centre at 1-877-362-7434 and a refund cheque will be issued.

Should a chargeable balance result after the annual reconciliation, the amount will be charged to your account and will appear on your July bill. In the event that the BBP Final Adjustment charge is higher than expected, you may choose to call the Enbridge Call Centre at 1-877-362-7434 and one of our Customer Service Representatives will work with you to determine suitable payment arrangements.

At a minimum, one mid-season BBP review will occur usually at the beginning of the next calendar year. The mid-season review will recalculate your monthly BBP installment to ensure accuracy as weather, usage and rate changes could affect the actual charges for gas you use. After the mid-season review, the new monthly installment amount will be billed on your next bill and a bill message will explain that there was a review of your monthly BBP installment.

Customers are encouraged to monitor their BBP details (actual gas charges billed to date versus BBP installments billed to date) and may request a review at any time.

A number of factors can create a variance in the plan. Significant changes in weather, gas prices, change in gas marketers, or gas use in the home, such as installing a new natural gas appliance, can create a difference between actual gas costs and installment amounts.

First time gas customers are automatically assigned to the BBP unless they request otherwise.

6.4.5.Payment Options

- **Pre-Authorized Payment**

Enbridge also offers a Pre-Authorized Payment Plan. Signing up for the Pre-Authorized Payment Plan will allow your amount due to be automatically withdrawn from your bank account on the day before the Late Payment Effective Date.

- **Other payment options include:**

  - Online or in person at a financial institution
  - Telephone Banking
  - Credit Card
    For a Credit Card Convenience fee of $2.85 for every $150 charge paid to our Credit Card Service Provider, you may use a valid credit card to make a payment.
  - Western Union
    For customers with overdue amounts that are at or nearing disconnection for non-payment, you may choose to make a payment for a fee through Western Union.
  - Standard Mail
    You can send a cheque or money order (no cash please), along with the bottom tear-off portion of your bill, to:

    Enbridge
    P.O. Box 644
    Toronto, ON M1K 5H1

    Please make your cheque payable to "Enbridge" and write your account number on the front.

- Pay in Person
  You may also drop your payment off at one of our payment drop boxes located in the following locations 24 hours a day:
  (Please note: for your security, we cannot accept cash at these offices.)

  VPC Office
  500 Consumers Road
  North York, Ontario

  Ottawa Office
  400 Coventry Road
  Ottawa, Ontario

  Thorold Office
  3401 Schmon Parkway
  Thorold, Ontario

6.5. Correction of Billing Errors

Retroactive billing ensures that all gas consumption and other Enbridge charges, not billed previously, are billed correctly to the customer. Retroactive billing can be the result of either a customer error or a company error. When a customer has been billed incorrectly, retroactive billing is required.

Where billing errors, either through company or customer error, have resulted in either under or overbilling, the customer will be charged or credited with the amount erroneously billed for a period not exceeding two years.

If you have been under-billed, Enbridge will work with you to determine a suitable payment arrangement.

6.6. Discontinuance of Gas Supply or Delivery

6.6.1. Customer Initiated Discontinuance

A customer will continue to be bound by these Conditions of Service and will be obliged to pay for all gas supplied and/or delivered to the premises along with any other monthly charges applicable including late payment penalties until Enbridge has terminated the supply of gas following the acceptance of a request for termination from the customer.

6.6.2. Emergency or Safety related Discontinuance

In addition to service interruption for maintenance and force majeure events, Enbridge may discontinue gas supply and/or delivery to any customer for any of the following reasons:

- for use of gas for any purpose other than that described in the service application, gas supply contract, or rate schedule;
- in case Enbridge, is refused access for any lawful purposes to the premises to which gas is supplied and/or delivered;
- when Enbridge property on a customer’s premises is in any manner tampered with, damaged, or destroyed;
- when Enbridge has reason to believe that an unsafe condition exists on the premises or may develop from a continuation of gas supply and/or delivery;

- when a gas installation contravenes the provisions of the Technical Standards and Safety Act, associated regulations, or any other applicable enactment; or
- when there is evidence of gas theft.

Discontinuance of gas supply and/or delivery for any of the reasons set out in paragraph 6.6.2 shall result in a disconnection charge payable by the Customer.

6.6.3. Discontinuance of Service for Non-payment

Enbridge charges are due when the bill is received, which is considered to be three days after the date the bill is rendered. If, for any reason, you are unable to make full payment you are encouraged to contact Enbridge to make suitable payment arrangements. Customers can call the Enbridge Call Centre at 1-877-362-7434.

If the bill is not paid in full and you have not contacted Enbridge to make payment arrangements, under the Public Utilities Act, Enbridge has the right to discontinue gas service. Prior to discontinuance of gas service Enbridge will provide a minimum 48 hours' notice in writing to advise when the disconnection will occur. The written notice includes the dates between which the gas service can be disconnected and payment options for avoiding disconnection. An attempt to call you to discuss your gas account will also be made at this time.

If you are seeking payment assistance through a registered charity, government agency, social service agency or a third party, you must provide consent to Enbridge to provide details of your account to these third parties. Enbridge will place any disconnection or collections actions on hold and will work with the third party to obtain payment to avoid disconnection of your gas service.

If your meter has been turned off for non-payment, when payment in full is received by Enbridge including any disconnection charges and security deposit, Enbridge will reconnect your gas meter within 48 hours.

6.7. Arrears Management Programs

Enbridge has different arrears management programs available to customers who are unable to pay their entire bill. Enbridge works with customers depending on their individual circumstances to come up with a mutually agreeable payment arrangement. Customers requiring assistance are encouraged to call the Enbridge Call Centre at 1-877-362-7434 to discuss options.

Customers who miss making a payment as part of their payment arrangement will be sent a letter giving notice of the missed payment and the date on which their current arrangement will be cancelled.

In the event that you are having difficulty paying your bill, emergency financial assistance is also available. The Ontario Energy Board has initiated the Low Income Energy Assistance Program which operates similar to our Winter Warmth Program and provides financial assistance to families in need. You can choose to apply for financial assistance through various community agencies. Customers who are working with a social assistance agency will be given 21 days to secure emergency financial assistance before additional collection action will be taken for non-payment. Eligible Low Income Customers that enter into a payment agreement will have the Late Payment Charges waived on the payment arrangement balance. In the event that an Eligible Low-Income customer defaults on an arrears payment agreement, then the option to have late payment charges waived with any future arrears payment agreement will no longer be automatically available. Disconnection of gas service is always a last resort.

6.8. Allocation of Payments between gas and non-gas charges

Payments are applied to your gas bill charges based upon the oldest billed amounts being paid first. In the event that payment is insufficient to cover all charges invoiced in a month, payments will be allocated to non-gas charges first, unless otherwise notified of a dispute. Any charges that remain outstanding past the late payment effective date will incur a late payment charge as mentioned in the Bill issuance and Payment section.

6.9. Management of Customer Accounts

Enbridge is committed to providing excellent service and to ensuring that relationships with customers are conducted with integrity and in a responsible, fair, honest and ethical manner. Consistent with these objectives Enbridge maintains high standards of confidentiality with respect to the personal information in its possession. Any personal information related to a customer's account will only be shared with the party named on the account or any third party designated by the customer. To provide consent for another person or a third party to discuss your account details with Enbridge, you must contact our Enbridge Call Centre at 1-877-362-7434 to advise us of your permission to discuss your account with these parties.

Enbridge has improved processes for recording Landlord directions on how to manage accounts in between tenants. We can record the following directions:

- Always lock the account between tenants. This requires a written release to be signed by the Landlord accepting full responsibility for any damages caused by not having heat available during the winter season
- Lock the account in summer and move the account to the Landlord's name in winter
- Move the account into the Landlord's name in between tenants
- Always leave the account in the Landlord's name
- Move out the tenant only

6.10. Our Customer Service Process

Step 1: Call the Enbridge Call Centre at 1-877-362-7434
Enbridge customer service representatives (CSRs) are trained to help answer your questions.

Step 2: Ask to Speak to a Supervisor
If you feel that your questions are not being fully addressed by the CSR, please ask to speak to a supervisor. They'll try to work with you to resolve your issue.

Step 3: Contact the Enbridge Customer Ombud
If you've spoken to a CSR and a supervisor and are not completely satisfied with the solution provided, the supervisor will offer to elevate your concern to the Enbridge Customer Ombud's office.

For complete information regarding our dispute resolution process, please visit the Enbridge website: https://www.enbridgegas.com/contact-us/

APPENDIX A

DEFINITION OF TERMS

British thermal unit – means the amount of heat required to raise the temperature of one pound of distilled water from 60° Fahrenheit to 61° Fahrenheit.

Building piping – includes pipe, whether indoors, outdoors, exposed or buried, which brings gas from the "point of delivery" to each point of utilization including plugged or capped gas valves.

Cubic metre - A standard cubic metre of gas is the volume of gas contained in a one cubic metre at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa"). 10^3m^3 equals 1,000 cubic metres.

Curtailment - An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Customer – means any person, persons, company or corporation responsible for purchasing gas through Enbridge's meter.

Gas – natural gas or its equivalent containing not less than the heating value specified from time to time in Enbridge's rate schedules.

Gas appliance – means any device approved by the appropriate governmental authority which uses gas as a fuel or as a raw material.

Joule - A measurement of heat.

Late payment effective date – means the date late payment charges will be added to your bill if full payment has not been received.

Late payment charge – means a charge which is imposed when full payment of the gas bill is not made by the "late payment effective date".

Meter – means a device approved by the appropriate governmental authority and installed to measure the volume of gas delivered to the customer.

Month or monthly – means, for the purposes of calculating customers' accounts, a period of approximately 30 days.

Point of delivery – means that point at which gas leaves Enbridge's metering and regulating facilities and is delivered to you or, if there are no such facilities, Enbridge's shut-off valve.

Property line – means that line which delineates the boundary between one property and the next immediately adjacent property whether it is public or private.

Rate schedule – means one of a set of schedules filed by Enbridge with and approved by the Ontario Energy Board that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Service – means the pipe or tubing and associated fittings which transmits gas from the pipeline to the meter inlet connection. Where unmetered gas is provided, the service shall be deemed to terminate at the shut-off valve located closest to the building entry, immediately inside the building wall. Where gas pressure regulation is necessary, the service regulator shall form part of the service.

Standard conditions – Temperature of 60°F and 15°C for Imperial and S.I. respectively. Pressure of 14.73 pounds per square inch absolute (psia) and 101.325 kilopascals absolute (kPa) for Imperial and SI respectively. Water vapour content less than 7 pounds per million cubic feet and 100 milligrams per cubic metre for Imperial and SI respectively.

SCHEDULE OF SERVICE CHARGES – "RIDER G"

1. In addition to gas distribution rates and rates charged for gas commodity provided by the Company, Enbridge maintains a list of charges that apply to specific customer initiated services provided by the Company. Since these are typically one-time services initiated by the customer, it is more appropriate to recover the costs associated with such services from those customers requiring them from time to time, as opposed to recovering these costs from all customers as a component of gas distribution rates. The revenues associated with these charges are discussed at Exhibit C1, Tab 4, Schedule 1.

2. Certain of these services are related to gas distribution field operations and are based upon an hourly charge-out rate, which in some cases also includes a material component. Fees for operations related services were updated in 2009 based on approval from the Board in EB-2008-0219. Other fees listed in Rider G pertain to customer care activities.

3. Enbridge has undertaken a review of its Schedule of Service Charges, as shown in the Rate Handbook at Rider G. This review has indicated that Enbridge's current rates for these services are comparable with those of other Ontario service delivery organizations and utilities, and in most instances are lower. The Company has concluded that no change will be required to these fees throughout the 2014 through 2016 incentive rate period. As a result, Enbridge is proposing no change to Rider G service fees in this rate application.

4. Table 1, sets out Enbridge's proposed service charges for the 2014 through 2016 proposed Enbridge incentive rate period.

Witnesses: S. McGill
M. Torriano

Table 1- Proposed Rider G - Service Charges

Account Related Charges	Rate (excluding taxes)
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied.	$25.00
Appliance Activation Charge (*for Commercial Customers Only*) Charged to commercial customers for appliance activation on unlock and red unlock orders, except on the first unlock and service unlock at a premise.	$70.00 Minimum 1/2 hour work. Total amount depends on time required.
Meter Unlock Charge (*Seasonal or Pool Heater*) Seasonal for all customer classes, or pool heater for residential only.	$70.00
Statement of Account	
Lawyer Letter Handling Charge Providing the customer's lawyer with gas bill information.	$15.00
Statement of Account Charge (for One-Year History)	$10.00
Cheques Returned Non-Negotiable Charge	
Cheques Returned Non-Negotiable Charge	$20.00
Gas Termination	
Meter Lock re. non-payment “Red Lock Charge” Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by field collector).	$70.00
Removal of Meter Removal of a meter by construction and maintenance crew.	$280.00

Witnesses: S. McGill
M. Torriano

Cut Off at Main Charge Cutting service off at main by construction and maintenance crew.	$1,300.00
Valve Lock Charge Shutting off service by closing the street shut-off valve.	
- Work performed by field investigator.	$135.00
- Work performed by construction and maintenance personnel.	$280.00
Safety Inspection	
Inspection Charge For inspection of gas appliances; the Company provides only **one** inspection free of charge, upon the first time gas is introduced to a premise.	$70.00
Inspection Reject Charge (Safety Inspection) Energy Board Inspection rejects billed to the meter installer or homeowner.	$70.00
Meter Test	
Meter Test Charge Where a customer disputes meter reading(s), the customer may request to have the meter tested. This charge applies if the test confirms that the meter is recording consumption correctly.	
- Residential meters	$105.00
- Non-residential meters	Time and material per contractor

Witnesses: S. McGill
M. Torriano

Street Service Alteration	
Street Service Alteration Charge For installation of service line beyond allowable guidelines (for new residential services only).	$32.00 / metre
NGV Rental	
NGV Rental Cylinder (Weighted Average)	$12.00 / month
Other Customer Services (Ad-hoc request)	
Labour Hourly Charge-Out Rate	$140.00
Cut Off at Main Charge (*Commercial and Special Requests*) applicable to commercial services and other residential services that involve significantly more work than the average will be custom quoted.	Custom quoted
Cut Off at Main Charge (*Other Customer Requests*) Other residential requests due to demolitions, fires, inactive services will be charged at the standard COAM rate.	$1,300.00
Meter In-Out (*Residential Only*) Relocating the meter from inside to outside per customer request.	$280.00
Request for Service Call Information Provide written information of the result of a service call as requested by home owners.	$30.00
Temporary Meter Removal At the customer's request.	$280.00
Damaged Meter Charge	$380.00

Witnesses: S. McGill
M. Torriano

CURRICULUM VITAE OF
TIM ADAMSON

Experience:	Enbridge Gas Distribution Inc.
	Manager, Sustainable Energy 2008
	Program Manager, Sustainable Energy 2002
	Senior Advisor, Safety and Environment 1993
Education:	MSc. Soil Surveying and Pedology, University of Reading, UK B.Sc. Honours. Soil Science, University of Newcastle upon Tyne, UK. Canadian Certified Environmental Practitioner (2005)
	Various Other Training Courses (e.g. CSA ISO 14064 – 2, Carbon Finance, web writing, marketing for engineers).
Memberships:	Chair, Canadian Energy Partnership for Environmental Innovation (CEPEI) Board Member, Smart Commute, North Toronto Vaughan
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
TUNDE ADESIPO

Experience:	Enbridge Gas Distribution Inc.
	Manager, IT Business Support 2010
	Manager, Internal Controls 2010
	Senior Leader, Governance & Internal Controls 2007
	Deloitte & Touche LLP
	Senior Accountant 2005
	UNIC Insurance Plc
	Executive Director Finance & Administration 2001
	PricewaterhouseCoopers LLP
	Audit Manager 1998
	Senior Auditor 1993
Education:	Masters of Business Administration (Banking & Finance) Certified Public Accountant (US CPA) Associate Chartered Accountant (ACA) Certified Information Systems Auditor (CISA)
Memberships:	Information Systems Audit and Control Association (ISACA)
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
FAHEEM AHMAD

Experience:	Enbridge Gas Distribution Inc.
	Manager, Customer Portfolio and Policy 2010
	Program Manager, Financial Assessment 2007
	Supervisor, Gas Supply Analysis 2006
	Program Manager, Portfolio Management 2004
	Program Manager, Capital Appropriations 2003
	Senior Advisor, Financial Business Performance 2001
	Enbridge Incorporated
	Financial Analyst, Business and Financial Analysis 2000
	Lahore Electricity Supply Company
	Manager, Operations 1996
Education:	Certified Management Accountant (CMA) Society of Management Accountants, 2004
	Master of Business Administration Wilfred Laurier University, 1999
	Master of Science, Electrical Engineering University of Engineering and Technology, Lahore, Pakistan, 1992
Memberships:	The Society of Management Accountants of Ontario Professional Engineers of Ontario

Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0277 EB-2010-0146 RP-2002-0133

CURRICULUM VITAE OF
WILL AKKERMANS

Experience: Enbridge Gas Distribution Inc.

Director, System Operations – Operations Senior VP
2011

General Manager Ottawa – Operations Leadership
2007-2010

Director, Customer Care RFP Project – Customer, Reg. & Public Affairs
2006

General Manager Central Region
2003-2004

Manager Trans Serv/Gas Supp Operations
2000

Manager Special Projects
1999

Manager Supply Management Services
1996-1998

Supervisor Gas Control
1994-1996

Supervisor Pipeline
1993-1994

Pipeline Inspector
1992

Enbridge Inc.

Director, Business Technology
2006

Director, Asset Technology Management
2005-2006

Manager International Business Development
2000-2003

Education: Master of Business Admin, 1999

Bachelor of Science – Civil Engineering, 1993

Memberships: Professional Engineers of Ontario

CURRICULUM VITAE OF
JIM ALTON

Experience: Enbridge Gas Distribution Inc.

Director, Asset Renewal and Improvement
2012

General Manager, Toronto Region
2011

Directory, Safety & Reliability
2009

General Manager, Central Region West
2008

Group Manager – Work Management Centre
2006

Manager, Operations Solutions
2006

Manager, Field Force Transformation
2004

Manager, Eastern Region Operations
2001

Manager, Engineering Maintenance
1999

CSA International

Project Manager, Oil & Gas Standards
1998

SENES Consultants Limited

Associate and Senior Environmental Engineer
1990

Consumers Gas Company Ltd

Assistant Manager, Gas Supply
1987

Project Engineer, LNG Project
1985

Manager, Operations Information Systems
1983

Distribution Planning Engineer
1980

<u>TransCanada Pipelines</u>

Jr. Engineering Assistant
1977

Education: B.A. Sc., Chemical Engineering
University of Toronto, 1980

Economics and Fundamental Accounting courses
York University, 1982

LNG Plant Operations Course
Institute of Gas Technology, 1985

Microprocessor Based Programmable, Controllers
University of Toronto, 1986

Canadian Securities Course
Investment Dealers Association, 1987

Compliance with Environmental Legislation
University of Toronto, 1990

Queens Executive Management Program
Queens University, 2003

Memberships: Professional Engineers Ontario

Appearances: (Ontario Energy Board)
EB-1985-LNG

CURRICULUM VITAE OF
LINDA AU

Experience: Enbridge Gas Distribution Inc.

Capital Budget Manager
2007

Capital Budget Supervisor
1995

Revenue and Gas Cost Analyst
1991

Canada Post Corporation

Operations Planning and Budget Officer
1990

Financial Analyst
1988

Queen Elizabeth Hospital

Senior Accountant
1986

Education: Certified General Accountant
CGA Ontario 1991

Bachelor of Business Management
Ryerson 1986

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0008
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2006-0034
RP-2005-0001

CURRICULUM VITAE OF
PRAMOD BHATIA

Experience: Enbridge Inc.

Senior Manager, Treasury
2013

Manager, Treasury
2010

Senior Advisor, Enterprise Risk
2008

Federal Home Loan Bank of Dallas

Senior Risk Analyst
2007

Fannie Mae

Senior Portfolio Analyst, Portfolio Risk Management
2005

Credit Risk Manager, Counterparty Risk Management
2003

BNP Paribas

Head – Cash Management
1997

Citibank

Manager
1995

Education: Master of Science, 2002

Master of Business Administration, 1995

Bachelors of Engineering, 1992

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
ROBERT ALAN BOURKE, CMA

Experience: Enbridge Gas Distribution Inc.

Manager Regulatory Proceedings
2004

Manager Budget and Administration – Operations
2003

Manager Regulatory Accounting
1998

Senior Analyst Regulatory Accounting
1995

Supervisor Revenue and Gas Cost
1992

Centra Gas (Ontario) Inc.

Supervisor, Budget Administration
1992

Thornhill Glass & Mirror Inc.

Controller
1988

The Consumer Gas Company Limited

Manager System Customer Billing
1987

Management Trainee
1986

Supervisor Income and Cash Budget
1982

Asst. Supervisor Income and Cash Budget
1980

Education:	Certified Management Accountant (CMA), 1981
Memberships:	The Society of Management Accountants Ontario
Appearances:	(Ontario Energy Board) EB-2012-0055 EB-2011-0354 EB-2011-0277 EB-2011-0226 EB-2011-0008 EB-2010-0146 EB-2010-0042 EB-2009-0172 EB-2008-0219 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0048 RP-2002-0133 RP-2001-0032 RP-2000-0040 RP-1999-0001 EBRO 497 EBO 179-14/15

CURRICULUM VITAE OF
JOHN S. BRIGGS

Experience: Enbridge Gas Distribution Inc.

Manager, Asset Management Services
2011

Manager, Engineering Budgets
2008

Manager, Operations Budgets & Administration
2005

Manager, Capital Knowledge Centre
2002

Team Lead, Oracle EFS FA, PA, OPA
2001

GT Group Telecom

Manager, Capital Assets
2000

A.G. Simpson Automotive Inc.

Manager, Capital Appropriations & Expenditures
1998

Manager, Financial Reporting
1994

Alcan Aluminium Ltd.

Manager, Accounts Receivable
1988

Education: Bachelor of Arts
Victoria College University of Toronto, 1985

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2005-0001
RP-2003-0203
RP-2002-0133

CURRICULUM VITAE OF
MICHAEL BROPHY

Experience:	Enbridge Gas Distribution Inc.
	Sr. Manager, Operations Solutions 2010
	Manager, DSM & Portfolio Strategy 2004
	Manager, Sales 2001
	Senior Specialist, Environment Health & Safety 1999
Education:	Masters of Business Administration, University of Toronto 2004
	Masters of Engineering, Civil Engineering, University of Toronto 1997
	B.A.Sc., Civil Engineering, University of Waterloo 1994
Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board) EB-2009-0154 EB-2009-0103 EB-2008-0384 EB-2008-0346 EB-2008-0271 EB-2007-0893 EB-2006-0034 EB-2006-0021 EB-2005-0001 EBLO 261/EBC 266/EBA 785 EBLO 260 EBLO 261 EBC 266 EBA 785 PL 97

CURRICULUM VITAE OF
RYAN CHEUNG

Experience:	Enbridge Gas Distribution Inc.
	Senior Budget Analyst, Budget and Planning 2010
	Supervisor, Margin Planning and Analytics 2006
	Analyst, Volumetric Analysis and Budgets 2004
	TD Canada Trust
	Financial Service Advisor 2000
Education:	Bachelor of Arts, in Economic and Statistics University of Toronto
Appearances:	(Ontario Energy Board)

CURRICULUM VITAE OF
SAMIR CHHELAVDA, CA, CIA, CRMA

Experience: Enbridge Gas Distribution Inc.

Assistant Controller
2012

Manager, Strategy Execution and Performance Management
2011

Chief Auditor
2010

Manager, Audit Services
2005

Duffy, Allain & Rutten, LLP

Senior Audit Manager
2003

AXA Canada Inc.

Senior Financial Analyst
2002

Ernst & Young, LLP

Audit Manager
2001

Senior Staff Accountant
1999

Schwartz, Letivsky, Feldman LLP

Staff Accountant
1997

Education: Certification in Risk Management Assurance
Institute of Internal Auditors, 2011

Certified Internal Auditor
Institute of Internal Auditors, 2006

Chartered Accountant
Canadian Institute of Chartered Accountants, 2000

	Graduate Diploma in Public Accountancy McGill University, 1997
	Bachelor of Commerce – Accounting McGill University, 1995
Memberships:	Canadian Institute of Chartered Accountants Institute of Chartered Accountants of Ontario Institute of Internal Auditors Ordre des Comptables Professionnels Agréés du Québec
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
LLOYD A. CHIOTTI

Experience: Enbridge Gas Distribution Inc.

Director, Distribution Asset Management
2010

Director, Asset Management Strategy
2006

General Manager, Envision Program
2003

General Manager, Central Region
2002

Director, Business Optimization
2001

Director, Operations Services
1999

Director, Business Transformation
1998

Regional General Manager, Central Region
(incl. Metro, Eastern, Western & Northern Zones)
1997

Regional General Manager, Metro Region
1992

Regional General Manager, Western Region
1989

Director, Information Services
1987

Manager, Systems Development
1984

Project Manager, Systems & Planning Dept.
1979

Datacrown

Data Processing Consultant
1977

Sears Canada Ltd.

Manager of Programming Services
1971

Education: Bachelor of Applied Science, Electrical Engineering
University of Toronto

Masters of Business Administration
University of Toronto

Memberships: CGA – Chair, Asset Management Task Force
IGU – Member Working Committee 4 - Distribution

Appearances: (Ontario Energy Board)
EB-2011-0354
RP-2003-0203
RP-2002-0133
RP-2001-0032
RP-1999-0001
EBO 179-14/EBGO 179-15
EBA 795

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Design
2003

Manager, Rate Research
2000

Senior Rate Research Analyst
1996

Centra Gas Ontario Inc.

Manager, Rate Design
1995

Supervisor, Cost of Service Studies
1990

Education: Bachelor of Business Management
Ryerson Polytechnical Institute, 1988

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0242
EB-2010-0146
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
EBRO 489
EBRO 474-B, 483,484
EBRO 474-A
EBRO 474
EBRO 471

(Régie de l'énergie/Régie du gaz naturel)
R-3793-2012
R-3758-2011
R-3724-2010
R-3692-2009
R-3665-2008
R-3637-2007
R-3621-2006
R-2587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
LORI CORNWALL

Experience: Enbridge Gas Distribution Inc.

Associate General Counsel & Director, Gas Distribution Law
2012 - Present

Senior Legal Counsel
2007 – 2012

Davies Ward Phillips & Vineberg, LLP

Partner, Competition Law and International Trade
1997 – 2006

Associate
1995 - 1997

Sole Practitioner – Criminal Law

1992 – 1995

McMillan, LLP (formerly McMillan Binch)

Associate
1991

Education: Bar Admission Course – Called to the Ontario Bar
Law Society of Upper Canada, 1991

Masters of Business Administration
University of Ottawa, 1989

Bachelors of Laws,
University of Ottawa, 1989

Bachelor of Arts (Honours)
Carleton University, 1985

Memberships: Law Society of Upper Canada
Canadian Bar Association/Ontario Bar Association

Appearances: (Ontario Energy Board)
EB-2011-0354

CURRICULUM VITAE OF
LAWRENCE COWIE

Experience: Enbridge Gas Distribution Inc.

Manager, Operations, Customer Safety and Compliance
2012

Manager, Fleet Management
2009

Field Manager, Operations
2004

Supervisor, Operations
1992

Supervisor, Damage Prevention
1991

1st Class Gas Technician
1978

Labourer
1976

Education: High School – G.E.D.

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
ANNE M. CREERY

Experience: Enbridge Gas Distribution Inc.

Director, Quality & Training
2012

Group Manager, Work Management Centre
2010

Manager, Customer Care Operations
2005

Manager, Business Change Realization
2004

Union Gas Ltd.

Project Manager, Operations
2004

District Manager, Operations
1999

Manager, Solutions Realignment Project
1997

Manager, Business Support
1995

Assistant to the Senior Vice-President of Operations
1993

Supervisor, Sales Administration
1989

Sales Representative
1988

Education: Master of Business Administration
Queen's University, 1997

Honours Bachelor of Commerce
University of Windsor, 1986

Appearances: (Ontario Energy Board)
EB-2006-0034

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
2003

Senior Analyst, Regulatory Accounting
1998

Analyst, Regulatory Accounting
1991

Assistant Analyst, Regulatory Accounting
1989

Budgets – Capital Clerk, Budget Department
1987

Accounting Trainee, Financial Reporting
1984

Education: CMA (3rd level)
Seneca College 1987-89 (business/accounting)

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0226
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0104/EB-2008-0408
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203

CURRICULUM VITAE OF
DEAN DALPE

Experience: Enbridge Gas Distribution

Director, Storage Operations
2012

TransAlta Energy Corporation
1998-2012

Director of Eastern Canada Gas Operations

Plant Manager, Sarnia Regional Cogeneration Facility

Assistant Plant Manager, Sarnia Regional Cogeneration Facility

Maintenance Supervisor, Sarnia Regional Cogeneration Facility

Atomic Energy of Canada

Controls Specialist
1994

Education: Queen's University, Master of Business Administration (E.M.B.A.)
2011

China Europe International Business School (CEIBS)
Business in China Elective, Shanghai, China
2012

Cambrian College of Technology, Instrumentation Engineering Technologist
Cambrian College of Technology, Electronic Engineering Technician
1991

Certification: Certified Industrial Instrument Mechanic
Certified Industrial Electrician
4th Class Power Engineer

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
JOEL DENOMY

Experience:	Enbridge Gas Distribution Inc.
	Manager, Gas Supply & Strategy 2010-Present
	Manager, Strategic Planning 2009-2010
	Manager, Economic and Market Analysis 2007-2009
	Supervisor, Economic and Market Analysis 2006-2007
	Senior Market Analyst, Volumetric and Market Analysis 2003-2006
	Market Analyst, Volumetric and Market Analysis 2002-2003
Education:	Chartered Financial Analyst CFA Institute, 2006
	Master of Arts (Economics) University of Waterloo, 2002
	Bachelor of Arts (Honours Economics, Finance Specialization) University of Waterloo, 1999
Memberships:	Canadian Association of Business Economists (CABE) Toronto CFA Society
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2010-0333 EB-2008-0219 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0203

(Regie De L'Energie)
R-3587-2005
R-3665-2008

(New York State Public Service Commission)
08-G-1392

CURRICULUM VITAE OF
ROB DiMARIA

Experience: Enbridge Gas Distribution Inc.

Manager, Key Accounts and Vendor Relationships
2009

Account Executive
2006

Senior Marketing Specialist
2003

Residential Program Manager
2001

Senior Analyst, Planning and Evaluation
2000

Rate Research Analyst
1998

Plant Accounting Chief Clerk
1994

Accounting Trainee
1992

Education: Bachelor of Administration, Business Management, Athabasca University
Diploma in Accounting and Financial Management, Centennial College

Appearances: (Ontario Energy Board)
EB-2001-0032

CURRICULUM VITAE OF
TANYA M. FERGUSON

Experience: Enbridge Gas Distribution Inc.

Senior Manager, Customer Care Operations
2013

Manager Customer Care Operations, Customer Care
2010

Manager Customer Care Financial Administration, Customer Care
2006

Manager Special Projects, Customer Care
2005

Senior Analyst, Planning and Projects
2002

Supervisor, Internal Reporting
2000

Enbridge Services Inc.

Financial Analyst, Financial Reporting
1999

Enbridge Gas Distribution Inc.

Corporate Accountant, Financial Reporting
1998

Audit Assistant, Audit Services
1998

Accounting Trainee, Financial Reporting
1997

Education: Masters of Business Administration
York University, 2002

Certified Management Accountant
Society of Management Accountants, 2000

Bachelor of Commerce (Honours)
University of Windsor, 1996

Memberships:	Certified Management Accountant Society of Management Accountants
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0277 EB-2010-0146 EB-2005-0001 RP-2003-0203

CURRICULUM VITAE OF
M. CRAIG FERNANDES

Experience: Enbridge Gas Distribution Inc.

Senior Manager, Regulatory, GTA Project
2013

Manager, Regulatory Project Development
2011

Senior Project Manager, Major Reinforcements
2010

Manager, Operations Projects
2009

Senior Project Manager, Operations Solutions
2006

Program Manager, Energy Technology
2005

Celestica Inc.

Global Pricing Advisor
2003

Senior Regional Cost Engineer
2002

Financial Cost Engineer
2000

Manufacturing Engineering Team Leader
1999

Senior Associate Prototype Engineer
1997

Carrier Canada Ltd.

Automation Controls Specialist
1995

Customer Service Representative
1994

Education:	Bachelor of Applied Science, Mechanical Engineering, University of Waterloo, 1993
	Masters of Business Administration University of Toronto, 1999
Memberships:	Association of Professional Engineers Ontario, 1997
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
RALPH J.W. FISCHER

Experience:

Enbridge Gas Distribution Inc.

Director, Regulatory Special Projects
2011

Enbridge Pipelines Inc.

Director, Planning and Analysis
2005

Terasen Pipelines (now Kinder Morgan Canada)

Director, Economics and Regulatory Affairs
2003

EnCana Pipelines

Director, Economics and Regulatory Affairs
2001

TransCanada PipeLines Ltd.

Director, Economics and Regulatory Affairs (Express Pipeline Partnership)
Manager, Business Development
Coordinator, Investor Relations
Senior Financial and Regulatory Analyst
1990

Home Oil Company

Senior Financial Analyst, Corporate Planning
1988

Interprovincial Pipe Line Ltd.

Supervisor, Forecasting
1981

Education:

Honours Bachelor of Science, University of Toronto, Toronto
Masters of Business Administration (Finance), Schulich School of Business, York University, Toronto

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354

CURRICULUM VITAE OF
PAUL GREEN

Experience: Enbridge Gas Distribution Inc.

Director, Public & Government Affairs and Customer Ombudsman
2012

Director, Sales
2008

Market Development
2005

Direct Energy Business Services

Area Director, Southwest Ontario
2005

JRL HVAC Inc.

Director, Sales Development
2003

Direct Energy Essential Home Services

Director, Sales Development
2002

Enbridge Home Services

Director, Sales Development
1999

Enbridge Consumers Gas

Manager, Retail Sales and Service
GTA North and Georgian Bay
1997

The Consumers' Gas Company Ltd.

Regional Sales Manager
Western Region
1994

Commercial / Industrial Sales Manager
Western Region
1990

Manager, Innovators Circle
Human Resources
1988

Residential Sales Manager
Metro Toronto Region
1986

Commercial / Industrial Sales Supervisor
Metro Toronto Region
1984

Commercial / Industrial Sales Representative
Metro Toronto Region
1981

Residential Sales Representative
Metro Region
1979

Customer Account Representative
Metro Toronto Region
1977

Merchandise Account Clerk
October 1976

Education: Bachelor of Administrative Studies
York University
1998

Queen’s University Executive Development Program
1998

Syracuse University
Sales and Marketing Program
1993 / 1994

Appearances: (Ontario Energy Board)
EB-2008-0271
EB-2006-0034
EB-2006-0021

Grand Valley East Garafraxa Franchise (Leave-to-Construct)
1994

Dundalk / Flesherton / Markdale Franchise Hearing 1995

CURRICULUM VITAE OF
ANTON KACICNIK

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Research & Design
2007

Manager, Cost Allocation
2003

Program Manager, Opportunity Development
1999

Project Supervisor, Technology & Development
1996

Pipeline Inspector, Construction & Maintenance
1993

Education: Bachelor of Applied Science (Civil Engineering)
University of Waterloo, 1996

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0106
EB-2008-0219
EB-2007-0615
EB-2007-0724
EB-2006-0034
EB-2005-0551
EB-2005-0001

(RÉGIE DE L'ÉNERGIE)
R-3724-2010
R-3665-2008
R-3637-2007
R-3621-2006
R-3587-2006
R-3537-2004

CURRICULUM VITAE OF
SAGAR KANCHARLA

Experience: Enbridge Gas Distribution Inc.

Director, Business Performance
2011

Director, Strategy, Research & Planning
2008

Manager, Planning & Economics
2007

Manager, Financial and Economic Assessment
2005

Manager, Financial Assessment
2003

Senior Advisor, Financial Assessment
2002

Enbridge Inc.

Financial Analyst, Business & Financial Analysis
2000

GE Silicones India Pvt. Ltd., India

Manager – Market Development
1996

Ciba Specialty Chemicals Ltd., India

Product Manager – Pigments Division
1994

Marketing Executive – Polymers Division
1992

Education: Masters of Business Administration
McMaster University, 2000

Post Graduate Diploma in Management
Indian Institute of Management, Ahmedabad, India, 1992

	Bachelor of Engineering (Civil Engineering) Andhra University, Visakhapatnam, India, 1990
Membership:	Society of Utility and Regulatory Financial Analysts
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0277 EB-2007-0615 EB-2006-0066 EB-2006-0034 EB-2005-0539 EB-2005-0001 RP-2004-0015 RP-2003-0203

CURRICULUM VITAE OF
LORRAINE KENNEDY

Experience: Enbridge Gas Distribution Inc.

Manager, Budgets and Scorecard
2008

Supervisor Business Support
2005

Sr. Analyst, Budget & Financial Reporting
2001

Analyst, Opportunity Development
1999

Balance Sheet Clerk, Finance
1997

Intermediate Bank Reconciliation Clerk, Finance
1992

Accounts Payable Clerk, Finance
1991

Education: Queens Leadership Program
2010

Dale Carnegie Training - Presentation Skills
2010

Facilitation First – Internal Consulting Workshop
2010

Centennial College C.I.
Business Administration – General Management Diploma
1980 to 1983

Appearances: (Ontario Energy Board)
EB-2011-0354

CURRICULUM VITAE OF
MATTHEW KIRK

Experience:	Enbridge Gas Distribution Inc.
	Cost Allocation Manager, Regulatory Affairs 2012
	Senior Rate Design Analyst, Regulatory Affairs 2010
	Rate Design Analyst, Regulatory Affairs 2009
	Market Analyst, Economic and Market Analysis 2006
Education:	Master of Arts (Economics) Wilfrid Laurier University, 2006
	Bachelor of Arts (Honours Economics) McMaster University, 2005
Memberships:	Canadian Association of Business Economists (CABE)
Appearances:	(Ontario Energy Board) EB-2012-0055 EB-2011-0354
	(Régie de L'Energie) R-3793-2012

CURRICULUM VITAE OF
TARA KATHLEEN KNIGHT, CA

Experience: Enbridge Gas Distribution Inc.

Manager, Capital Management
2012

Manager, Financial Reporting & Analysis
2008

Supervisor, External Reporting & Pensions
2006

Rogers Communications Inc.

Senior Financial Analyst
2005

PricewaterhouseCoopers LLP

Senior Associate
2003

Cooperative Education Program
2000 - 2002

Education: Chartered Accountant (CA), 2005

Master of Accounting, University of Waterloo, 2003

Honours Bachelor of Arts – Accounting, University of Waterloo, 2002

Memberships: Institute of Chartered Accountants of Ontario (ICAO)
Multiple Sclerosis Society of Canada – Finance Committee

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
DANNY KO

Experience:	Enbridge Gas Distribution Inc.
	Senior Budget Analyst 2011
	IBM
	Financial Analyst 2004
Education:	Certified General Accountant (CGA), 2009
	Bachelors of Business Administration, 2004
	Bachelors of Science, 2000
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
KERRY LAKATOS-HAYWARD

Experience: Enbridge Gas Distribution

Director, Customer Care
2010

Director, Operations Services
2008

Director, Business Development & Strategy
2006

Manager, Business Development & Strategy
2003

Manager, Volumetric & Market Analysis
2000

Manager, Multi-Family Marketing
1997

Senior Economist, Economic Studies
1995

Ontario Hydro

End Use Economist, Load Forecasts
1994

Evaluation Analyst, Planning & Evaluation
1992

Education: Bachelor of Arts (Specialist in Economics)
University of Toronto, 1990

Master of Science in Planning (Environmental Planning)
University of Toronto, 1992

Queen's Executive Program, 2005

Certificate in Carbon Finance, 2008

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
RP-2006-0034
RP-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040

CURRICULUM VITAE OF
DOUGLAS F. LAPP

Experience: Enbridge Gas Distribution Inc.

Director, Operations Governance and Control
2012

Chief Engineer
2011

Director, Engineering & Construction
2010

Chief Safety Officer
2006

Manager, Chief Operations & Logistics Engineer
2003

General Manager, Niagara Region
2002

Manager, Operations & Engineering Ozz Energy Project
2001

Manager, Distribution Planning
1999

Manager, Year 2000 Business Continuity Planning
1998

Manager, Distribution Operations, Northern Region
1995

Manager, System Regulation
1994

Manager, Engineering Projects
1991

Manager, Planning & Technical Services, Niagara Region
1990

Supervisor, Maintenance, Metro Toronto Region
1989

Senior Distribution Engineer, Congas Engineering Canada Ltd.
1988

Senior Engineer, Operations Engineering
1987

Project Engineer, Eastern Region
1985

Operations Engineer, Operations Engineering
1982

Education: Queens Executive Program, 1998

University of Toronto
Master of Engineering in Welding, 1990

University of Waterloo
Bachelor of Applied Science in Civil Engineering, 1982

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2007-0615
EB-2006-0034
RP-2005-0001
RP-2003-0203
RP-2002-0133
RP-2000-0040
RP-1999-0001
EBRO 495
EBRO 487/ EBRO 485
EBLO 241
EBLO 256/EBA 737/EBC 246
EBLO 261/EBA 785/EBC 266
EBA 795

CURRICULUM VITAE OF
LISA L. LAWLER

Experience: Enbridge Gas Distribution Inc.

Director, Integrity
2010

Chief Engineer
2008

Manager, Enbridge Ontario Wind Power Project
2006

Manager, Strategic Distribution Alliance
2004

Manager, Distribution Planning
2001

Manager, Operations Eastern Region
1999

Manager, Distribution Expansion
1997

General Supervisor, Maintenance (West)
1996

Supervisor, Construction & Maintenance Administration
1995

Operations Engineer
1991

Congas Engineering Canada Limited
(a former subsidiary of The Consumers' Gas Company Ltd.)
International Marketing Engineer
1989

Education: Master of Business Administration
Wilfrid Laurier University, 1989

Bachelor of Applied Science, Chemical Engineering, Honours Program
University of Waterloo, 1988

Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board) EB-2011-0354 RP-2002-0133

CURRICULUM VITAE OF
JAMIE LeBLANC

Experience: Enbridge Gas Distribution Inc.

Director, Energy Supply and Policy
2013

General Manager - Gazifère Inc.
2010

Manager, Finance and Control – Enbridge Gas New Brunswick Inc.
2005

Supervisor, Financial Reporting – Enbridge Gas New Brunswick Inc.
2004

Education: Chartered Accountancy Designation
Atlantic School of Chartered Accountants, 1998

Bachelor Business Administration
University of New Brunswick, Fredericton, 1996

Memberships: The New Brunswick Institute of Chartered Accountants

Appearances: (Régie de l'énergie/Régie du gaz naturel)
R-3793-2012
R-3758-2011

(New Brunswick Energy and Utilities Board)
Cost of Capital for Enbridge Gas New Brunswick (EGNB) – 2010
EGNB Financial Results 2009 – 2010
EGNB Cost of Service Study – 2010
EGNB LFO Rate Changes – 2010
EGNB Various Rates and HFO Rates - 2010
EGNB Development Period – 2009
EGNB Financial Results 2008 – 2009
EGNB Financial Results – 2007 - 2009

CURRICULUM VITAE OF
RAYMOND LEI

Experience:	Enbridge Gas Distribution Inc.
	Manager, Budgets and Business Support 2010
	Manager, Corporate Budgets and Analysis 2007
	Manager, Financial Analysis 2007
	Senior Analyst, Planning and Projects 2005
	Rogers Wireless Inc.
	Senior Analyst, Budgets and Forecast 2001
	Royal LePage Relocation Services Ltd.
	Financial Analyst 2000
	Kodak (China) Limited
	Business Analyst 1995
Education:	Certified General Accountant Certified General Accountants of Ontario, 2005
	Master of Business Administration York University, 2000
	Bachelor of Arts in Commerce and Economics Sichuan University, China
Memberships:	Certified General Accountant, Ontario

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172

CURRICULUM VITAE OF
LEE LIAUW

Experience: Enbridge Gas Distribution Inc.

Cost Allocations Specialist
2012

Manager, Business Performance
2008

Manager, Scorecard & Capital Appropriation
2002

Manager, Management Reporting & Analysis
2001

Ontario Hospital Association
1990

Financial Controller

Manager, Finance & Control

Manager, General Accounting

Education: CFA (Chartered Financial Analyst) Charterholder
September 2005

CMA (Certified Management Accountant)
1988

Bachelor of Commerce
University of Toronto 1981

Membership: Society of Management Accountants of Ontario
Institute of Management Accountants
Institute of Certified Financial Analysts
Toronto Society of Financial Analysts

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2005-0001

CURRICULUM VITAE OF
MICHAEL LISTER

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Policy & Strategy
2010

Manager, Investment Planning
2006

Manager, Volumetric & Market Analysis
2004

Supervisor, Volumetric & Market Analysis
2003

Sr. Market Analyst, Volumetric & Market Analysis
2002 - 2003

NRI Industries Inc.

Production Scheduler, Logistics
1999-2000

Fairlee Fruit Juices Ltd.

Raw Materials Coordinator
1998

Coats Canada Inc.

Production Planner, Materials & Logistics
1996-1997

Education: Chartered Financial Analyst
CFA Institute, 2005

Master of Business Administration
York University, 2002

Bachelor of Commerce
St. Mary's University, 1996

Memberships: CFA Institute
Toronto CFA Society

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2010-0060
EB-2009-0172
EB-2009-0084
EB-2007-0615
EB-2005-0001
RP-2003-0203

(New York Public Service Commission)
05-G-1635

(New York Public Service Commission)
08-G-1392

CURRICULUM VITAE OF
TREVOR MACLEAN

Experience: Enbridge Gas Distribution Inc.

Director, Market Development & Sales
2012

Director, Business & Market Development
2008

Enbridge Gas New Brunswick

Manager, Distribution Operations
2006

Manager, Sales & Marketing
2004

RLG International

Consultant
2000

825929 Alberta Ltd

Consultant
1997

ISM (IBM Global Services)

Director, Systems Integration
1995

Manager Operations, Systems Integration
1994

National Defence/Canadian Forces

Military Officer
1986

Education: Master of Business Administration
Queen's University, 1995

Bachelor of Arts (Special)
University of Alberta, 1986

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354

CURRICULUM VITAE OF
ANDREW MANDYAM

Experience: Enbridge Gas Distribution Inc.

Senior Manager, Incentive Regulation Financial Planning
2013

Manager, Marketing and Energy Efficiency
2011

Manager, Demand Side Management and Portfolio
2010

Customer Information System Replacement Project Business Manager
2007 - 2009

Manager, Customer Care and Customer Information System Program Operations
2006

Manager, Information Technology Solutions and Support
2005

Senior Project Manager, Information Technology Solutions and Support
2003

Oracle Corporation

Practice Manager
1997 – 2003

Compaq Canada

Program Manager
1995 – 1997

Ontario Hydro

Associate Engineer
1990 - 1995

Education: B.A.Sc. Mechanical Engineering
University of Toronto
1990

Memberships:	Professional Engineers of Ontario Project Management Institute
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0295 EB-2011-0277 EB-2010-0146 EB-2010-0175 EB-2010-0029 EB-2009-0172 EB-2006-0034

CURRICULUM VITAE OF
STEVE MCGILL

Experience: Enbridge Gas Distribution Inc.

Manager, Customer Care Finance & Contracts
2012

Manager, Billing & Customer Systems
2005

Manager, Strategic Projects & Market Analysis
2003

Manager, Customer Support & Advocacy
2000

Manager, Customer Accounting Projects
1995

Manager, Large Volume Billing
1992

Manager, Industrial Sales, Metropolitan Toronto
1990

Manager, Rate & Contract Administration
1987

Rate Research Analyst
1985

Market Analyst
1981

Distribution Planner
1979

TransCanada Pipelines Limited

Junior Statistician

Junior Draftsman

Education:	Bachelor of Arts (Honours Geography), University of Toronto, 1978
	Miscellaneous short courses in Public Utility Management, General Management, and Accounting
Other:	Member of the Board of Directors and Treasurer of the Oshawa Ski Club
Appearances:	(Ontario Energy Board) EB-2012-0055 EB-2011-0354 EB-2011-0277 EB-2011-0226 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133 RP-2001-0032 RP-2000-0040 RP-1999-0058 RP-1999-0001 EBRO 497-01 EBRO 497 EBRO 495 EBRO 492 EBRO 490 EBRO 487 EBO 179-14/15

CURRICULUM VITAE OF
DARREN MCILWRAITH

Experience: Enbridge Gas Distribution Inc.

Senior Manager, Business Development and DSM Technology
2009

Enbridge Solutions Inc.

Manager, Product Development
2006

Direct Energy Marketing Limited

Director, Customer Analytics
2004

Director, Financial Services
2002

Enbridge Commercial Services Inc.

Director, Financial Services
2001

Enbridge Gas Distribution Inc.

Manager, Budgets
2000

Supervisor, Budgets & Forecasts
1998

Economic Analyst
1996

Education: Master of Arts: Business Economics, Wilfrid Laurier University – 1996
Bachelor of Commerce, University of Guelph - 1994

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
CHRIS MEYER

Experience:	Enbridge Gas Distribution Inc.
	Manager, External Communications 2011
	Manager, Executive Communication Support 2008
	Senior Communication Advisor 2001
Education:	Strategic Communication Management Certificate (Ithaca College), 2008
	Bachelor of Applied Arts, Journalism (Ryerson), 1990
Memberships:	International Association of Business Communicators (Accredited)
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
BIJU MISRA

Experience:	Enbridge Gas Distribution Inc.
	Director Information Technology, 2013
	Sr. Manager Business Applications, 2009
	IT Solution & Support Manager, Information Technology, 2008
	Sr. Project Manager, Information Technology, 2007
	Project Manager, Information Technology, 2006
Education:	Bachelor of Science, Electrical Engineering. Kansas State University Certificate, Business Management Fundamentals. University of Toronto
Memberships:	Project Management Institute (PMI)
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
DONALD RITCHIE (RITCH) MURRAY, PEng

Experience:	Enbridge Gas Distribution Inc
	Manager, Natural Gas for Transportation Business Development Jan 2013 to present
	Project Manager, LNG Business Development Jan 2012 to Dec 2012
	Project Manager, Engineering Major Works Nov 2009 to Jan 2012
	Project Manager, Engineering Standards and Technical Services Jun 2008 to Nov 2009
	Program Manager, Asset Management Jun 2006 to Jun 2008
	Field Manager, Quality Acceptance Aug 2003 to Aug 2004
	Engineering Project Leader Jun 2000 to Aug 2003
	Enbridge Gas New Brunswick Inc
	Manager, Planning and Technical Services Aug 2004 to Jun 2006
Education:	Master of Business Administration Ryerson University, 2008
	Bachelor of Engineering (Mechanical) Dalhousie University, 2000
	Bachelor of Science (Biology) Acadia University, 1994
Memberships:	Professional Engineers of Ontario Professional Engineers and Geoscientists of New Brunswick
Appearances:	Petitcodiac River Crossing Project, Leave to Construct Hearing, 2006 (New Brunswick Energy and Utilities Board)

CURRICULUM VITAE OF
STUART MURRAY

Experience:	Enbridge Gas Distribution Inc.
	Senior Manager, Investment Review 2013
	Manager, Investment Review and Economic Analysis 2011
	Manager, Investment Review and Customer Growth 2008
	Manager, Financial Assessment 2006
	Pitney Bowes Canada
	Project Manager, Enterprise Program Office 2003
	Finance Manager, Service Operations 2001
	Finance Manager, New Business Development 2000
	Canadian Tire Corporation
	Business Analyst, Marketing Finance 1997
	Financial Analyst, Corporate Planning 1996
Education:	Master of Business Administration McMaster University, 1995
	B.A. Economics, Administrative & Commercial Studies University of Western Ontario – 1993
Membership:	None
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2006-0034

CURRICULUM VITAE OF
ERIK NACZYNSKI, P.Eng

Experience: Enbridge Gas Distribution Inc.

Manager, System Analysis and Design
2010

Manager, Records and GIS
2009

Project Manager, Major Projects
2006

Engineering Project Leader
2005

Union Gas

Distribution Planning EIT
2003

Education: Bachelor of Engineering and Management

Memberships: Professional Engineers Ontario

Appearances: (Ontario Energy Board)
EB-2007-0692
EB-2006-0305

CURRICULUM VITAE OF
FIONA OLIVER-GLASFORD

Experience: Enbridge Gas Distribution Inc.

Senior Manager, Market Policy and DSM
2013

Union Gas Distribution

Manager, CDM Business Development and Policy
2010

Manager, DSM Strategy
2008

Manager, DSM EM&V
2007

Manager, DSM Programs/Marketing
2006

Manager, Market Research & Analysis
2005

Canadian Energy Efficiency Alliance

Director, Operations

Summerhill Group

Marketing Manager

Corus Entertainment

Marketing Manager, YTV, Documentary Channel and Scream TV

Towers Watson

Associate/Analyst

Education: York University – Schulich School of Business
Masters of Business Administration

Western University – Huron College
Bachelor of Arts

Memberships: None

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
EDWARD PHAGOO

Experience: Enbridge Gas Distribution Inc.

Manager – IT Solutions and Support
2010

Program manager
2009

Sr. Project Manager
2007

Rogers Communication Inc..

Sr. Project Manager
1990

Education: Bachelors of Science, Devry University

Memberships: Project Management Institute

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
BRAD S. PILON

Experience:	Enbridge Gas Distribution Inc.
	Manager, Finance and Administration Gas Storage 2001-Present
	Manager, Administration - Gas Storage 1991-2001
	Tecumseh Storage Analyst 1988-1991
	Manager, Marketing Studies 1986-1988
	Financial Analyst, Exploration 1982-1986
Education:	Executive Education Program for the Natural Gas Industry University of Colorado 1990
	Graduate Studies Masters of Business Administration Program University of Western Ontario 1979-1980
	Bachelor of Arts, Economics University of Western Ontario 1979
Memberships:	Ontario Petroleum Institute
Appearances:	(Ontario Energy Board) EB-2011-0354 RP-2003-0203 EBRO 466 EBRO 455

CURRICULUM VITAE OF
SANDEE QIAN

Experience:	Enbridge Gas Distribution Inc.
	Ops Budget & Analysis Manager, Finance 2012
	Manager Margin Budget & Analysis, Finance 2010
	Manager Financial Analysis, Corporate Budget & Analysis 2008
	Program Manager Capital Appropriation & Scorecard, Finance 2006
	Senior Financial Analyst, Financial Assessment 2006
	Financial Analyst, Financial Assessment 2004
	Motorola (China) Electronics Ltd.
	Senior Analyst 1995
Education:	Certified Management Accountant (CMA), 2007
	Master of Business Administration York University, 2003
	Bachelor of Engineering Northwestern Polytechnic University, China
Memberships:	The Society of Management Accountants Ontario
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
PETER RAPINI

Experience:	Enbridge Gas Distribution Inc.
	Sr Manager, Facilities Services 2010
	Manager, IT Technical Services 2003
	Enbridge Commercial Services
	Manager, Computer Operations 2000
	The Consumer Gas Company Limited
	Manager Client Technology Management 1997
	Supervisor Network Support 1992
	Sr Coordinator Network – IS Analyst 1988
	Coordinator Network 1984
	Intermediate Operator 1982
	Jr Operator 1981
	Tape Librarian 1981
Education:	Herzing College
Memberships:	International Facility Management Association (IFMA)
	BOMA
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
BARRY REMINGTON

Experience:	Enbridge Gas Distribution Inc.
	Manager, Property Taxes Land Services Department 1990
	Bell Canada
	Manager, Property Valuation Property Tax Department 1978
	Marathon Realty Company Limited
	Property Tax Representative 1976
	Ministry of Revenue – Assessment Division
	Property Assessor 1973
Memberships:	Canadian Property Tax Association, Inc. (CPTA) (Past President of CPTA in 1996) Institute of Municipal Assessors Institute for Professionals in Taxation (IPT)
Committee:	CPTA Board of Directors – National Treasurer CPTA Past Presidents Committee IPT Canadian Liaison Committee
Education:	Assessment Administration Diploma Loyalist College, 1973
Appearances:	Assessment Review Board (ARB) Assessment Appeal Tribunal for Property Assessment and Taxation
	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
ROCCO RICCIO

Experience: Enbridge Gas Distribution Inc.

Lead, Facilities Services Governance
2011

Manager, Facilities Services
2006

Supervisor, Facilities Services
2003

Manager, Finance regulatory
2002

Manager, Capital Knowledge Centre
2000

Manager, Financial Statement Forecasts
1996

Manager, Budgets and Administration, Information Services
1993

Supervisor, Income and Cash Budgets
1986

Supervisor, Capital Budgets
1982

Accounting Trainee
1980

Education: Certified General Accountant
Certified General Accountants Association of Ontario, 1990

Accounting/Finance Diploma
Ryerson Polytechnical Institute, 1980

Appearances: (Ontario Energy Board)
EB-2011-0277
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001
EBRO 497
EBRO 495

CURRICULUM VITAE OF
JAMES E. SANDERS, P.Eng.

Experience:

Enbridge Gas Distribution

Director, Market and Business Development
2012

Director, Storage Operations
2008

Manager, Strategic Distribution Alliances
2006

Duke Energy Gas Transmission
Manager, Major Projects
2005

Union Gas Limited
Manager of Operations Support
2003

Manager Operation Engineering
2000

Manager of Business Development
1999

Manager of Operations and Construction
1993

Planning and Project Engineer
1989

Nuclear Activation Services Ltd.
Manager of Operations
1986

Education:

McMaster University
Masters of Engineering and Public Policy
2010-2011

University of Waterloo
Bachelor of Applied Science, Civil Engineering
1981-1986

Memberships: Professional Engineers of Ontario, 1988, 40537201

Appearances: (Ontario Energy Board)
EB-2011-0354
RP-2003-0063
E.B.A. 691
E.B.A. 691
E.B.C. 206,
E.B.A. 670
E.B.A. 700-708
E.B.C. 233-255
E.B.L.O. 253
E.B.C. 213
E.B.A. 687

CURRICULUM VITAE OF
HULYA SAYYAN

Experience:	Enbridge Gas Distribution Inc.
	Advisor, Economic & Market Analysis 2011
	Senior Market Analyst 2007
	Risk Software Technologies
	Economic Specialist 2005
	Marmara University
	Assistant Professor, Econometrics Department 2002
	Instructor, Econometrics Department 2001
	Research Assistant, Econometrics Department 1994
Education:	Ph.D. in Econometrics Marmara University, 2000
	Master of Science in Statistics Marmara University, 1995
	Bachelor of Science in Statistics Mimar Sinan University, 1992
Memberships:	Toronto Association for Business & Economics (CABE)
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0277 EB-2010-0146

CURRICULUM VITAE OF
JASON SHEM

Experience:	Enbridge Gas Distribution Inc.
	Senior Advisor, Financial Reporting 2012
	Financial Analyst 2011
	SF Partnership, LLP
	Senior Accountant 2009
	Ernst & Young
	Senior Accountant 2008
	Staff Accountant 2007
Education:	Chartered Accountant (CA), 2010
Memberships:	Institute of Chartered Accountants of Ontario
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
DONALD R. SMALL

Experience: Enbridge Gas Distribution Inc.

Manager, Gas Costs and Budget
2010

Manager, Gas Cost Knowledge Centre
2003

Manager, Gas Costs and Budget
1989

Co-ordinator, Gas Costs
1984

Financial Statement Accountant
1980

Chief Clerk, Financial Statements
1979

Advanced Accounting Trainee
1978

Education: Business Administration Diploma
Ryerson Polytechnical Institute, 1978

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
EB-2010-0146
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001
EBRO 497

EBRO 495
EBRO 492
EBRO 490
EBRO 487
EBRO 485
EBRO 479
EBRO 473
EBRO 465

CURRICULUM VITAE OF
RYAN SMALL

Experience:	Enbridge Gas Distribution Inc.
	Senior Analyst, Regulatory Accounting 2006
	Analyst, Regulatory Accounting 2004
	Supervisor, Gas Cost Reporting 2001
	Senior O&M Clerk 2000
	Bank Reconciliation Clerk 1999
	Accounting Trainee 1998
Education:	Certified Management Accountant, The Society of Management Accountants of Ontario, 2003
	Diploma in Accounting, Wilfrid Laurier University, 1997
	Bachelor of Arts in Economics The University of Western Ontario, 1996
Appearances:	(Ontario Energy Board) EB-2012-0055 EB-2011-0354 EB-2011-0008

CURRICULUM VITAE OF
PATRICIA A. SQUIRES

Experience: Enbridge Gas Distribution

Director, Strategy, Planning and Analytics
2011

Manager, Operations PMO
2011

Manager, Market Development
2008

Manager Mass Markets and New Construction Market Development
2006

Manager, Energy Technology
2004

Manager, DSM and Program Evaluation
2001

Manager, Planning and Evaluation
1998

Senior Evaluation and Market Planning Analyst
1997

Conservation Analyst
1994

Economic Researcher
1991

Research Assistant
1990

Education: Master in Business Administration (candidate)
Rotman School of Management, 2014
University of Toronto

Master in Environmental Studies
York University, 1996

Bachelor of Applied Arts (Applied Geography)
Ryerson Polytechnic University, 1990

Certificate in Economic Analysis
Ryerson Polytechnic University, 1990

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2010-0175
EB-2009-0172
EB-2009-0154
EB-2008-0150
EB-2006-0034
EB-2006-0021
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2000-0040
RP-1999-0001

(Régie du Gaz Naturel)
R-3355-96

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience:

Enbridge Gas Distribution Inc.

Manager, Economic & Market Analysis
2012

Manager, Cost Allocation
2008

Manager, DSM Reporting & Analysis
2005

Analyst, Rate Design
2004

Senior Analyst, DSM Planning and Evaluation
2002

Senior Economic Analyst, Economic & Financial Studies
1998

The Canadian Institute

Conference Producer
1997

Margaret Chase Smith Center for Public Policy

Research Assistant
1995

Education:

Master of Arts in Economics
University of Maine, 1995

Bachelor of Arts in Economics
University of Maine, 1993

Appearances: (ONTARIO ENERGY BOARD)
EB-2011-0354
EB-2011-0277
EB-2010-0146
EB-2009-0172
EB-2008-0219
EB-2008-0106

(RÉGIE DE L'ÉNERGIE)
R-3758-2011
R-3724-2010
R-3692-2009
R-3665-2008

CURRICULUM VITAE OF
STEFAN SURDU

Experience: Enbridge Gas Distribution Inc.

Sr. Engineering Manager, Measurement & Regulation,
Technology and Customer Safety
Since 2012

Manager, Special Projects and Distribution Technology
2011-2012

Sales Manager, Commercial Markets
2006 - 2011

Program Manager, Energy Technology
2006

Program Manager, Business Markets
2005 - 2006

Energy Solutions Consultant
2003 - 2005

Finn Projects Inc.

Project/Energy Engineer
2002 – 2003

Alfa Laval AB, Europe Central-East

Regional Sales Manager
2000-2001

Applications Engineer
1998-1999

National R&D Institute for Turbo-Engines, Romania

New Product Development Engineer
1997-1998

Education: M.Eng., Mechanical Engineering, Thermo-Mechanics of Machinery
Polytechnic University of Bucharest, Romania
1998

	B.Eng., Mechanical Engineering Polytechnic University of Bucharest, Romania 1997
Memberships:	Professional Engineers Ontario
Appearances:	(Ontario Energy Board) EB-2011-0295

CURRICULUM VITAE OF
NICK THALASSINOS

Experience:	Enbridge Gas Distribution Inc.
	Chief Engineer 2012
	General Manager, Central Region 2010
	Manager, Project Management Office 2009
	Manager, Asset Management Solutions 2006
	Manager, Business Transformation Development 2003
	Manager, Operations 2001
	Manager, Construction 2000
	Manager, Operations Engineering 1995
	Senior Engineer 1993
	Engineer Operations 1991
	Engineer Distribution 1990
	Engineer Distribution Planning 1989
Education:	Professional Engineer, 1991
	B.A.Sc. (Mechanical) University of Waterloo, 1989

Memberships:	Ontario Society of Professional Engineers
	CSA Z662 Technical Committee
Appearances:	(Ontario Energy Board) EB-2012-0451

CURRICULUM VITAE OF
MICHELLE TIAN

Experience: Enbridge Gas Distribution Inc.

Manager Operations Reporting
2013

Senior Financial Analyst, Operations Business Support
2010

Senior Financial Analyst, Corporate Budgets
2007

Evergreen
Accounting & Human Resources Coordinator
2006

Education: Certified Management Accountant, 2008
Honours Bachelor of Commerce, Queen's University, 2006

Memberships: The Society of Management Accountants Ontario

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
CHRIS TOMAN

Experience: Enbridge Gas Distribution Inc.

Sr. Manager Direct Purchase – Customer Care
2013

Sr. Manager Customer Systems – Customer Care
2009

Solution Manager CIS Project - Customer Care
2007

Manager Strategic Planning – Opportunity Development
2005

Business Systems Manager – Solutions Delivery Group
2004

Business Program Manager – Process and Projects
2001

Business Systems Manager – Transportation Contracting
2000

Analyst System Support & Development – Contract Support & Compliance
1997

Supervisor Market Systems – Market Planning & Evaluation
1994

Control Clerk LVB Systems – Key Account Services
1991

Clerk - Records & Stationery
1989

Education: Business Administration Diploma

Project Management Professional (PMP)

Memberships: Project Management Institute

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
MINA TORRIANO

Experience: Enbridge Gas Distribution Inc.

Manager, Operational Finance
2013

Manager, Business Support
2010

Manager, Operations Accounting
2006

Manager, Financial Asset Management
2005

Supervisor Asset Reporting and Analysis
2000

The Consumers Gas Company Ltd

Assistant Plant Accountant
1996

Systems Coordinator
1992

Plant Accounting Clerk
1987

Education: Accounting Degree – Humber College of Applied Arts & Technology

Appearances: (Ontario Energy Board)
EB-2011-0354

CURRICULUM VITAE OF
SHEILA TROZZI

Experience: Enbridge Gas Distribution Inc.

Sr. Manager Human Resources Business Support
2010

Human Resources Business Partner
2004

Human Resources Consultant
1998

Employee Relations Representative
1989

Human Resources Records Clerk
1980

Billing Clerk
1976

Education: Certified Human Resources Professional (CHRP 1993)

Memberships: Human Resources Professional Association

Appearances: (Ontario Energy Board)
EB-2011-0354

CURRICULUM VITAE OF
MICHAEL WAGLE

Experience:	Enbridge Gas Distribution Inc.
	Director, Operations 2013
	Operations Manager, Toronto Region, 2011
	Operations Manager, Central Region 2008
	Technical Services Manager, Eastern Region 2005
	Field Management Manager, EnVision Project 2003
	Operations Supervisor, Toronto Region 2002
	Construction Supervisor, Central Region 2002
	Engineering Project Leader 2000
	Pipeline Design and Analysis Supervisor, Eastern Region 1998
Education:	Carleton University Bachelor of Mechanical Engineering, 1998
Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
BARRY C. YUZWA

Experience: Enbridge Gas Distribution Inc.

Controller
2011

Director, Finance & Control
2010

Enbridge Inc.

Senior Director, Chief Audit Executive
Audit Services & Internal Controls
2007

Director, Audit Services
1999

Safeway Inc./Canada Safeway Limited

Manager, Corporate Audit Services
1991

Deloitte & Touche

Audit Manager
1987

Education: Certified Internal Auditor
Institute of Internal Auditors
2003

Chartered Accountant
Canadian Institute of Chartered Accountants
1986

Bachelor of Commerce-Accounting
University of Calgary
1983

Memberships: Canadian Institute of Chartered Accountants
Institute of Chartered Accountants of Alberta
Institute of Chartered Accountants of Ontario
Institute of Internal Auditors
Financial Executives International, Canada
Corporate Executive Board, Audit Directors and Risk Management Advisory Council
University of Calgary, Haskayne School of Business, Mentorship Program
Enbridge Inc. Mentorship Program

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0008

CURRICULUM VITAE OF
IRENE CHAN

Experience: Enbridge Gas Distribution

Senior Manager, Productivity and Business Analytics
2013

Manager, Gas Accounting and Analytics
2012

Manager, Margin Accounting, and Gas Analytics
2011

Manager, Margin Accounting, Business Performance and Analytics
2010

Manager, Margin Budgets and Accounting
2007

Manager, Margin Planning and Analysis
2006

Manager, Volumetric Analysis and Budgets
2003

Supervisor, Volumetric Analysis
2001

Senior Analyst, Volumes Knowledge Centre
2000

Economic Analyst, Economic Studies
1998

Queen's University

Instructor, Economics Department
1997

Research/Teaching Assistant, Economics Department
1992-1997

International Monetary Fund

Summer Intern, Research Department
1996

Consultant, Research Department
1994

<u>Bank of Canada</u>

Research Assistant, Research Department
1991

Education:	Certified Management Accountant, The Society of Management Accountants of Canada, 2006
	Ph.D. in Economics Queen's University, 1998
	Master of Arts in Economics Queen's University, 1993
	Bachelor of Arts (Honours) in Economics University of Western Ontario, 1991
Memberships:	Toronto Association for Business & Economics The Society of Management Accountants of Canada
Appearances:	(Ontario Energy Board) EB-2012-0055 EB-2011-0354 EB-2011-0008 EB-2010-0042 EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133

CURRICULUM VITAE OF
CATHY EGAN

Experience: Enbridge Gas Distribution Inc.

Director of System Measurement, Quality & Training
2013

Director of Safety
2012

Director of Safety & Training
2010

General Manager, Niagara Region
2008

President & General Manager, St. Lawrence Gas
2006

Group Manager, Work Management Centre
2005

Manager, New Construction & Mass Markets
2002

Manager, Mass Markets
2001

Market Sector Manager
1999

Group Manager Energy Efficiency Programs
1998

Manager, Distribution Expansion CR & NR
1997

Manager, Customer Attachment
1995

Manager, Metro Call Distribution Center
1994

Senior Supervisor Customer Inquiry
1991

Supervisor, Customer Service
1990
Representative, Telephone Service
1990

	Operator, Telephone Service 1987
	Clerk, Telephone Contact 1986
Education:	M.B.A., Clarkson University, Pottsdam, New York Degree Business, Ryerson University, Toronto
Memberships:	Board member of the HRAC Toronto Chapter Board member of the United Way of St. Catharines and EnerQuality Corporation Board member of Habitat for Humanity, Toronto
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
CATHERINE HO, CPA, CA

Experience: Enbridge Gas Distribution Inc.

Manager, Accounting
2012

Manager, Gas Accounting
2012

Manager, Finance Projects
2008

Senior Audit Advisor
2005

Ernst & Young LLP

Senior Staff Accountant
2004

Horwath Orenstein LLP

Staff Accountant
2002

Goldfarb, Shulman, Patel & Co. LLP

Staff Accountant
2000

Education: Chartered Accountant, 2005

Certified Public Accountant – Delaware, 2004

University of Waterloo – Waterloo ON
- Master of Accounting (MAcc), 2003
- Bachelor of Arts Honours Chartered Accountancy Studies – Co-operative program (Dean's Honours List), 2002

Memberships: Institute of Chartered Accountants of Ontario (ICAO)

Appearances: (Ontario Energy Board)
EB-2013-0046

CURRICULUM VITAE OF
TREVOR W. TUCK

Experience: Enbridge Gas Distribution Inc.

Director, Distribution Protection
2013 to Present

Manager, Operations Central Region East
2011 – 2013

Manager, Work Management Centre Operations
2008 – 2010

Manager, Engineer Capital Projects ESTS
2007 - 2008

Manager, Special Projects ESTS
2006 - 2007

Manager, Engineering Special Projects
2005

Project Manager, Engineering
2004

Project Engineer, Industrial Thermo Polymer Inc.
2002

Project Engineer, Applied Materials Japan Inc.
2001

Instructor, Aeon Inc.
2000

Mechanical Designer, Silex Inc.
1999

Mechanical Designer, Samuel Acme Inc.
1998

Education: Masters of Business Administration, Finance
Schulich School of Business, York University, 2006

Bachelor of Applied Science, Mechanical Engineering
University of Windsor 1998

Memberships: Professional Engineers Ontario

Appearances: (Ontario Energy Board)
EB-2006-0034

CURRICULUM VITAE OF
THO VUONG, P.Eng.

Experience: Enbridge Gas Distribution Inc.

Manager, System Measurement
2011

Construction Manager, Central Region West
2008

Manager, Work Management Centre
2006

Project Manager, FieldVision
2004

Manager, Joint Utility Construction
2002

Project Leader, Engineering
2000

Supervisor, Special Projects
1999

Supervisor, Planning and Technical Services
1998

Supervisor, Construction and Maintenance
1997

Pipeline Inspector, Construction
1995

Education: Professional Engineer (P.Eng.), 1997
B.A.Sc., University of Waterloo, 1995

Memberships: Professional Engineers Ontario

Appearances: (Ontario Energy Board)
None

Julia Frayer

Managing Director

LONDON ECONOMICS

KEY QUALIFICATIONS:

Julia Frayer is a Managing Director at London Economics International LLC ("LEI"), with more than 15 years of experience providing expert insights and consulting services in the power and infrastructure industries. Julia specializes in the analysis and evaluation of infrastructure assets; she has worked extensively in the US, Canada, Europe, and Asia in valuing electricity generation and wires assets, water and wastewater networks, as well as gas transportation assets. Julia manages LEI's quantitative, financial and business practice areas, and has built an in-house competency in issues related to market design, competitive market and auction design, capacity market analyses and strategic analysis of investment in wholesale power markets.

Julia manages LEI's quantitative financial and business practice area, and also specializes in market and organizational design issues related to electricity. In addition to electric generation sector market power and anti-trust analysis, sample projects include cost of capital estimation; rate-setting analysis; short- and long-term forecasting of wholesale power prices; valuation of generators and vertically-integrated utilities; assessment of retail market design including provider-of-last resort portfolios and contracts; advice on and design of energy sales agreements; and advisory on structuring request for proposals and sale processes for energy assets and derivative contracts. As part of these analyses, Julia and her team of economists and consultants have developed and applied proprietary real-options based valuation tools, portfolio risk analytics, models of strategic bidding behavior, and sophisticated power system simulation tools, as well as customized econometric models. Julia also leads many of the firm's regulatory economics projects, spanning such diverse issues as cost-benefit analysis, market power mitigation, tariff ratemaking, auction design (including competitive solicitations for procurement), wholesale market rules design, productivity analysis and efficiency benchmarking.

Julia also leads many of the firm's regulatory economics projects, spanning such diverse issues as cost-benefit analysis, market power mitigation, tariff ratemaking, auction design (including competitive solicitations for procurement), wholesale market rules design, and competitive market efficiency benchmarking. In the realm of cost-benefit analysis, she has dealt with investment appraisal, ratepayer impact analysis, RMR cost issues, and environmental siting issues. She has also worked on LEI's projects involving strategic advisory to governments, regulators, and other stakeholders regarding the structure of market institutions, such as Independent System Operators (ISOs), power exchanges, transmission system operators, etc.

Prior to joining LEI, Julia was working as an Investment Banker with Merrill Lynch in New York.

EDUCATION:

Institution	Graduate School of Arts & Sciences, Boston University
Degree(s) or Diploma(s) obtained:	MA in Economics

Institution	School of Arts and Sciences, Boston University
Degree(s) or Diploma(s) obtained:	BA in Economics and International Affairs

EMPLOYMENT RECORD:

Date:	February 1998-Present
Location:	Boston, MA
Company:	London Economics International

MOST RECENT PROJECT EXPERIENCE

PBR AND RATE DESIGN RELATED

Date:	2013
Location:	Canada
Company:	Private client
Description:	LEI was engaged by Enbridge Gas Distribution to provide an analysis of building block incentive ratemaking approaches used in Australia and the UK, and how they would apply to Enbridge's circumstances in Ontario. LEI's report supported Enbridge's distribution tariff proposal submission to the Ontario Energy Board for a second-generation Customized Incentive Regulation ("IR") plan for the period of five years (2014-2018). The testimony set out the theory behind as well as the practical experience of using the building blocks approach in incentive regulation regimes. Julia will provide the testimony for this project.

Date:	2012-2013
Location:	Alberta, Canada
Company:	FortisAlberta, Inc.
Description:	Julia provided support to FortisAlberta Inc. ("FAI"), a Canadian electricity utility, in its filing for its capital tracker application. LEI also reviewed the submissions of the intervenors and advised FAI on how to address the issues raised by these intervenors.

Date:	2011-2013 (ongoing)
Location:	Ontario, Canada
Company:	Ontario Power Generation

Description:	LEI was engaged by Ontario Power Generation ("OPG") to support senior management through regulatory processes related to performance-based rates. Julia and her team of experts prepared a discussion paper on incentive regulation mechanisms ("IRM") currently in place in Ontario for electricity and natural gas distribution utilities and presented it at a technical workshop at the Ontario Energy Board ("OEB"). LEI continues to support OPG as it moves to consider its next generation of rates.

Date:	2011-2012
Location:	Alberta, Canada
Company:	FortisAlberta, Inc.
Description:	Julia provided expert testimony in support of FortisAlberta Inc. ("FAI"), a Canadian electricity utility, in its filing for a performance-based ratemaking ("PBR") plan with the Alberta Utilities Commission ("AUC"). The testimony provided detailed data analysis (including inflation and TFP trends), underpinning PBR economic theory, and reviews of best practices in various North American and International jurisdictions. The testimony offers back up elements for each of the various components of the PBR plan that is being proposed by FAI. Julia testified at the AUC in Spring of 2012.

Date:	2011
Location:	USA, Canada, the Netherlands, UK, Australia
Company:	Private Company
Description:	Julia managed the writing of a white paper for Canadian electricity regulators and utilities on the comparative advantages and drawbacks of various tariff-setting regimes, from performance-based regimes to cost-of-service. This project involved a general overview of tariff-setting practices across Canadian provinces as well as highly detailed Canadian and international case studies and an examination of the key-lessons to be learned from each case. Detailed case studies covered the tariff-setting regimes in place in the UK, the Australian National Electricity Market and the Netherlands. As part of its deliverables, two workshops were conducted with a variety of regulators and utilities.

Date:	2010
Location:	Alberta and Ontario, Canada; UK; Australia
Company:	Private Company
Description:	For a Canadian client, Julia prepared a report that looks into the different capital expenditure recovery mechanisms utilized in four markets namely Australia, New Zealand, Ontario, and the UK for electric network utilities. The report also provided different options that the client can propose for its performance-based ratemaking filing.

Date:	2009
Location:	Canada
Company:	Coalition of Large Distributors in Ontario

Description:	Julia recently advised the Coalition of Large Distributors in Ontario on 3rd generation Incentive Regulation Mechanism proceedings of the Ontario Energy Board. The work involves expert testimony filed with the Board with detailed analysis of the theory behind the various components of PBR system, including inflation and efficiency gains factors, treatment of capital expenditures among others. The analysis was supplemented with comparison of actual factors and indices, and determination of the more robust and appropriate indices for the Ontario's distribution industry, including total factor productivity analysis for the sector

Date:	2008
Location:	Canada
Company:	Ontario Energy Board
Description:	Julia provided comments on the benchmarking methodology suggested by OEB consultants, looking at the analytical aspects of defining and benchmarking the performance of multiple utilities across long period of time. The critique provided details on how each criterion affects the benchmarking study and what are the remedies available to improve the results.

Date:	2008
Location:	Canada
Company:	Ontario Energy Board
Description:	Julia led a team that reviewed industry best practices in other jurisdictions and the current situation in Ontario to advise OEB on the appropriateness of the uniform transmission rate, as well as on the feasibility of moving to long-run zonally-differentiated marginal cost pricing. As part of this process, LEI undertook a comprehensive stakeholder review

OTHER EXPERT TESTIMONY

Date:	2013
Location:	United States
Company:	The New Mexico Express
Description:	Julia testified in front of the New Mexico Finance Authority Oversight Committee regarding the potential economic benefits of new investment in transmission in the state of New Mexico; Julia considered the impacts of local spending during construction of the proposed HVDC project on the state economy, using BEA RIMS multipliers to estimate the boost to economic activity. Julia also employed the DOE's JEDI model to estimate the potential for new jobs and GDP growth as a result of new renewables development in state (wind and solar) as a result of the transmission access that would be provided by the HVDC project.

Date:	2013
Location:	United States

Company:	ERCOT
Description:	Julia prepared a study of the Value of Lost Load ("VoLL") in ERCOT and evaluated current utility practices for manual load shedding. LEI's report on VoLL was filed with the PUCT in June 2013 under Docket 40000.

Date:	2013
Location:	United States
Company:	NRG
Description:	LEI was engaged by NRG to provide an independent review of the economic analysis in two reports: "Report and recommendations comparing repowering of Dunkirk Power LLC and transmission system reinforcements", published by National Grid ("NG") on May 17, 2013, and "NRG Dunkirk Repowering Project Economic Impact Analysis", published by Longwood Energy Group LLC ("LEG") on March 20, 2013. Both reports forecasted market benefits, production cost savings and macroeconomic benefits. LEI's review compared methodologies and assumptions used by each report, and how these may have affected their results; LEI's review was subsequently submitted by NRG to Case 12-E-0577 at the New York Public Service Commission (the "Commission").

Date:	2013
Location:	United States
Company:	Brookfield Renewable Energy Marketing
Description:	Julia and her team of economists supported the client in preparation of a merger application to the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act, in conjunction with the client's acquisition of a Maine-based hydroelectric generation portfolio. LEI performed a full Delivered Price test analysis for the ISO New England control area. LEI's analysis was filed with FERC and the Merger Application was approved in February 2013.

Date:	2012
Location:	United States
Company:	Morgan Stanley Capital Group
Description:	Julia provided testimony in support of transmission operating rules and curtailment protocols for interties into Alberta, as proposed by the Alberta Electricity System Operator ("AESO"), in order to support a fair, efficient and openly competitive power market. The testimony was made in front of the Alberta Utilities Commission ("AUC"), on behalf of Morgan Stanley Capital Group ("MSCG"), a customer of the Montana-Alberta Transmission Line. Julia's analysis considered commercial as well as operating protocols in deregulated power markets and considers how market rules incentivize new entry and produce dynamic efficiency gains related to more intense competition The AUC issued a favorable decision to MSCG in early 2013.

Date:	2011-2012
Location:	Alberta, Canada

Company:	TransAlta
Description:	Julia prepared testimony and testified in support of TransAlta in relation to a settlement for contravention of FEOC Regulation related to timing of exports from 2010. The settlement was crafted by the Market Surveillance Administrator and filed with the Alberta Utilities Commission for approval in December 2011. LEI assessed the economic and policy considerations of the settlement and its appropriateness in context of enforcement and sufficiency of penalty payment.

Date:	2012
Location:	United States
Company:	Public Utility Commission of Texas
Description:	Julia served as testifying witness and lead author in evaluating Entergy's decision to join the Midwest Independent Transmission System Operator ("MISO") Regional Transmission Organization ("RTO") on the behalf of the Public Utility Commission of Texas. LEI is evaluating several existing cost/benefit studies related to Entergy's decision to join MISO over the Southwest Power Pool ("SPP") and will be providing quantitative and qualitative analysis of specific costs/benefits attributable to ETI and its customers following membership in either MISO or SPP, including but not limited to net trade benefits, transmission cost allocation, governance issues, and continued participation in the Entergy Service Agreement following RTO membership.

Date:	2011-2012
Location:	United States
Company:	MPUC
Description:	Pursuant to An Act To Reduce Energy Prices for Maine Consumers, P.L 2011, ch.413, sec. 6 (Act) , the Maine Public Utilities Commission ("MPUC" or the "Commission") was directed by the Legislature to study Maine's renewable portfolio requirement established in 35-A M.R.S.A. § 3210 (3-A). London Economics International LLC ("LEI") was engaged by MPUC to conduct an in-depth analysis of the renewable portfolio standards ("RPS") required by the Act which would support the Commission's study and report to the Legislature. Julia led the team in preparation of the report, which was submitted to the Commission in January 2012 and later testified at the state legislature on the key findings of that report.

Date:	2011
Location:	United States
Company:	Public Service of New Hampshire
Description:	On behalf of Public Service of New Hampshire, Julia testified in front of the new Hampshire Senate Committee on issue of eminent domain generally and more specifically, on the power market context and near term outlook for the New England power market and reasons for the development of a new proposed transmission project known as Northern Pass.

Date:	2011

Location:	United States
Company:	Private Client
Description:	LEI developed simplified HHI screens looking at summer peak period for a client's potential acquisition of a gas-fired facility in New York. Several scenarios were developed to test the impact on HHI.

Date:	2011
Location:	USA
Company:	Private Client
Description:	Triennial market power analysis: in support of a client's application to renew market-based rate authorization under the provision of the Federal Energy Regulatory Commission ("FERC"), LEI performed Pivotal Suppliers Analysis and Market Share Analysis for the Northeast region, including New England, New York, PJM as well as the Connecticut, NYC and PJM East submarkets.

Date:	2010-2011
Location:	Northeast USA
Company:	Private Client
Description:	Market power analysis as a result of a proposed merger: in support of a client's opposition of a proposed utility merger in the Northeast US, LEI provided a white paper analyzing the impact of the merger on competition. The white paper covers analysis on buyer market power, concerns with utility's returning to rate base generation and vertical market power.

Date:	2010 – 2011
Location:	Massachusetts, United States
Company:	Private Client
Description:	Julia Frayer served as lead expert witness for a private equity investor in matter related to a contractual dispute regarding a long term power purchase agreement between a municipal utility located in New England and a landfill gas generator. Ms. Frayer analyzed key contractual terms of the PPA and provided an expert's review of how those terms compared to the industry norm when the contract was signed and became effective. Ms. Frayer provided an independent estimate of potential contractual damages. The case was scheduled be heard in Massachusetts Superior Court, however, Julia's analysis helped support a successful settlement.

Date:	2010-2012 (ongoing)
Location:	United States
Company:	Transmission Developers, Inc. ("TDI")

Description:	Julia led the detailed cost-benefit analysis and macroeconomic impact analysis in support of the Champlain Hudson Power Express ("CHPE") application for siting approval at the New York Department of Public Service ("DPS"). LEI's analysis on economic effects was the cornerstone of the settlement agreement reached between TDI and a number of New York agencies. Julia acted as independent expert on behalf of TDI and prepared updated study results on energy market impacts, capacity market impacts and also macroeconomic benefits stemming from the operation of the CHPE project. Julia's testimony was used in the DPS proceeding in the summer of 2012. Julia continues to support TDI on various market and regulatory issues in 2013.

Date:	2009
Location:	Canada
Company:	Brookfield Power
Description:	In the matter of Hawk Nest Hydro LLC acquisition of Hawk Nest-Glen Ferris Hydroelectric Project Julia and the LEI team prepared the MBR Authorization for the FERC filing. (Docket No. ER06-1446-000)

Date:	2007
Location:	Canada
Company:	Brascan Energy marketing, Inc.
Description:	In the context of a transmission rate case at the Regie (Quebec) and consideration of alternative transmission rate designs, Julia led the economic analysis for the client investigating the impact on trade from increased transmission costs, involving multi-factor regression analysis of nodal electricity prices, price spreads across markets, and interchange flows (imports and exports) across borders. Julia also considered the impact of the elasticity of demand for transmission services between Canadian provinces and US markets in the Northeast for maximizing revenues in rate setting. Julia provided testimony at the Regie.

Date:	2010-2011
Location:	United States
Company:	NRG (various acquisitions)
Description:	In support of various acquisitions, Julia prepared expert testimony for filing with FERC, related to Market-based Rate Authorization applications, Triennial Reviews, and Section 203 filings. All applications were successfully accepted by FERC.

Date:	2010
Location:	United States
Company:	Private Clients
Description:	In support of various acquisitions by Brascan and Emera in the Northeast announced in 2004, Julia prepared expert testimony for Market-based Rate Authorization applications, Triennial Reviews, and Section 203 filings.

Date:	2009-2010
Location:	United States

Company:	Maine Public Utilities Commission
Description:	Julia and the LEI team are currently assisting the Commission on the RFP related to the procurement of electricity in response to statutory mandates and state policy preferences. LEI provided economic analyses of bid proposals by estimating the benefits and costs to the ratepayers, and is currently supporting Commission staff in negotiations with short-listed bidders.

Date:	2009-2010
Location:	United States
Company:	Shell Energy
Description:	Ms. Frayer provided expert testimony before FERC related to Shell Energy's sale of capacity commitments from facilities in New York to New England in an alleged market manipulation case. Ms. Frayer examined market rules, operating procedures, and pricing arrangements in New England and New York at the time of the investigation, and examined the participation of Shell in the capacity markets and compliance offers in the energy markets, commenting on the economic rationale behind the client's must offer strategies in the energy market for capacity compliance.

Date:	2009-2011
Location:	United States
Company:	Private Client
Description:	Julia and her team assisted the client with certain matters pertaining to FERC investigation. Specifically, the scope of this retention includes economic and market analysis in support of a market participant in ISO New England's day ahead load response program ("DALRP"). Julia also provided affidavits and deposed in connection with FERC investigation of behind-the-fence industrial generator and participation in a wholesale power market in New England. Julia helped the client to respond to assertions of market manipulation and estimate market benefit provided through its participation in demand response program.

Date:	2009
Location:	United States
Company:	Maryland Public Utilities Commission
Description:	Julia submitted testimony on behalf of the Staff of the Maryland Public Service Commission ("MPSC") to the MPSC to conduct a cost-benefit analysis in relation to the proposed transaction between Constellation Energy Group, Inc. ("CEG") and Électricité de France ("EDF") whereby EDF would purchase from CEG a 49.99% interest in Constellation Energy Nuclear Group, LLC ("CENG"). Benefits related to the decreased likelihood of a Baltimore Gas & Electric ("BGE") downgrade, increased likelihood of the Calvert Cliffs expansion being completed and several macroeconomic benefits stipulated to by EDF. Costs related to the limitation on the allocation costs of CEG corporate support services to CENG, increased risk of capital deprivation and reduced quality of service, and implications of CEG's more aggressive nuclear development. (2009; MPSC, Case No. 9173)

Date:	2009

Location:	United States
Company:	Private Client
Description:	LEI advised a major transmission company on financial implications of proposed new 400kV transmission line to New York City and Connecticut. Analyzed impact of new transmission, assuming it delivered 100% carbon-free energy, on electricity prices and emissions levels in New York and New England.

Date:	2009
Location:	United States
Company:	Private Client
Description:	LEI was asked to evaluate third-party energy price forecast for the New England and Texas (ERCOT) regions, with a specific eye on the underlying assumptions. We recommended that certain key assumptions should be updated, including demand projections and CO2 price forecasts. We also argued that some underlying assumptions were unrealistic given actual market conditions, and should be adjusted or eliminated.

Date:	2009
Location:	United States
Company:	Maine Public Utilities Commission
Description:	As the team leader of this project, Julia assisted the Maine Public Utilities Commission in developing an electric resource adequacy plan to aid MPUC in the development of a strategy for the pursuit of the long-term contracts. LEI submitted a report that builds up a set of recommendations for a long-term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the Forward Capacity Market, an examination of historical price trends, and review of the investment needs assessments prepared by the utilities and ISO-NE, as well as relevant sub-regional planning studies.

Date:	2009
Location:	United States
Company:	Private Clients
Description:	Julia led a due diligence team and assisting in the exclusivity negotiations with respect to an acquisition of a 400+ MW coal fired plant in the PJM market by a group of private investors. Julia's role included management of LEI's economic appraisal, coordination of preliminary technical due diligence, negotiations with third parties on possible off-take arrangements, and oversight over financial modeling.

Date:	2009
Location:	United States
Company:	NRG

Description:	LEI was engaged by NRG Energy, Inc. to provide testimony in opposition to the proposed acquisition of NRG by Exelon Corp (Exelon). LEI performed a preliminary Herfindahl-Hirschman Index (HHI) test for market power for all regions affected, and a Delivered Price Test (DPT), including a more detailed HHI test, for the PJM East and ComEd regions. In addition, LEI examined Exelon's post-merger optimal bidding strategies using our proprietary model of strategic, known as CUSTOMBid. LEI also assessed the impact of changes in the parent company Exelon's cost of capital on the activities of the company's two regulated subsidiaries: ComEd and PECO. LEI also estimated the impact on customer costs from potential debt downgrades following the merger, and assessed the effectiveness of Exelon's proposed ring-fencing measures.

Date:	2009
Location:	United States
Company:	Private Client
Description:	Using LEI's proprietary simulation model of electricity wholesale markets in ISO New England, LEI forecast future cash flows for a portfolio of electricity generation assets and applied the net present value analysis to evaluate the portfolio's economic value under different potential future market conditions. This analysis supported the investment fund's decision to acquire and hold the generation portfolio's distressed debt

Date:	2009
Location:	United States
Company:	Private Client
Description:	Julia investigated opportunities for portfolio of biomass plants to earn renewable energy revenues from RECs, capacity markets, and carbon offsets given regulations in all states belonging to MISO, PJM, and ISO-NE. Engagement also involved formulating strategies for client to optimize the generation assets' revenue potentials by exploiting the identified renewable energy opportunities.

Date:	2009
Location:	United States
Company:	Private Client
Description:	Julia led a team analyzing potential revenues of pumped storage hydroelectric facilities (energy, capacity, ancillary services) proposed in various locations in ISO-NE and NYISO. The analysis included detailed simulations of the wholesale electricity markets, application of sophisticated statistical tools to estimate the volume and the price level of various ancillary services.

Date:	2009
Location:	United States/Canada
Company:	Private Client

Description:	Julia led a team that assisted a major Canadian renewable power company in its economic valuation of a New England based renewable company, prior to acquisition. Work involved due diligence, analyzing the revenue potential of the potential acquiree's assets over the 2009-18 period across all major ISO-NE product markets, and separately analyzed the market power implications of the acquisition in preparation of a potential FERC application, including analysis of market power issues in ancillary services market

Date:	2009
Location:	United States
Company:	Private Client
Description:	Julia evaluated potential value of assets available under various regional auctions for a dominant IPP player. Julia worked with the client in composing a bid proposal by assessing market risks posed by various factors, such as fuel price shifts, merchant plant construction scenarios, site conversion potential, and transmission constraints and through extensive production cost modeling

Date:	2009
Location:	United States
Company:	Maryland Public Utilities Commission
Description:	Julia submitted testimony on behalf of the Staff of the Maryland Public Service Commission (MPSC) to the MPSC to conduct a cost-benefit analysis in relation to the proposed transaction between Constellation Energy Group, Inc. ("CEG") and Électricité de France ("EDF") whereby EDF would purchase from CEG a 49.99% interest in Constellation Energy Nuclear Group, LLC (CENG). Benefits related to the decreased likelihood of a Baltimore Gas & Electric (BGE) downgrade, increased likelihood of the Calvert Cliffs expansion being completed and several macroeconomic benefits stipulated to by EDF. Costs related to the limitation on the allocation costs of CEG corporate support services to CENG, increased risk of capital deprivation and reduced quality of service, and implications of CEG's more aggressive nuclear development. (2009; MPSC, Case No. 9173)

Date:	2008-2009
Location:	United States
Company:	Private Client
Description:	In response to NU retaining LEI, New England wholesale electricity markets were simulated in order to determine whether the Greater Springfield Reliability Project ("GSRP") would produce economic benefits to the New England region. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. Using these simulations, a distribution of results was used to calculate confidence intervals and hypothesis tests run on the results, hence increasing the robustness of our findings. The study results were used to produce written testimony to the CSC and oral testimony was provided in late August and early September 2009.

Date:	2008
Location:	United States
Company:	PacifiCorp
Description:	Julia was part of a consortium that is serving as the Independent Monitor for PacifiCorp's renewable solicitation process for the 2008R-1 solicitation process for additional renewable power supplies. The Independent Monitor will report to the Utah Public Service Commission. This process includes review and assessment of the solicitation process, documents, and modeling methodologies; valuation of the bidder pre-approved process; development of review criteria, monitoring, auditing, and validation of bid evaluation process; bid evaluation; contract negotiation. Final report and testimony has been filed with the Utah PSC [Public Utility Commission of Oregon, Docket No. UM1368]

Date:	2008
Location:	United States
Company:	Brascan Power Generation LLC
Description:	Bear Swamp Power Company LLC (Bear Swamp) has asked Julia to perform a market power analysis in conjunction with Bear Swamp's application for market-based rate authorization. Similar study was done for Carr Street Generating Station L.P. ("Carr Street"), Erie Boulevard Hydropower L.P. ("Erie Boulevard"), and Brascan Power St. Lawrence River LLC ("St. Lawrence River"). Also for Brascan another MBR was filed that year: Brascan Power and Piney and Deep Creek LLC (Docket No. ER05-639-000)

Date:	2008
Location:	United States
Company:	Kentucky Public Service Commission
Description:	To satisfy the requirements of a recently passed statutory mandate, Julia and the LEI team conducted a broad-based analysis of current practices and the potential for reform within Kentucky's electricity industry in four areas: (i) energy efficiency and demand side management; (ii) use of renewables; (iii) full cost accounting; and (iv) tariffs. Reported results to the state's regulatory commission, including a full set of recommendations in each of the four areas for overcoming existing impediments to legislative objectives for improvements in the industry's overall efficiency and reductions in its environmental impact

Date:	2008
Location:	United States
Company:	Private Client

Description:	LEI served as an independent economic expert, opinion on specific matters related to a market participant's participation in the day ahead demand response program implemented by ISO-NE. LEI staff reviewed the specific facts of the case related to how the customer baseline was developed and the offering strategy of the market participant in the demand response program. LEI conducted independent analysis of the decision making process that had been undertaken in support of the customer baseline and offer strategy. LEI also prepared an analysis of the market benefits created for the market as a whole through the demand reductions offered by the market participant (a customized VBA model was created to reconstruct day-ahead ("DAH") and real-time ("RT") energy market clearing prices using public historical hourly offer and bid data). A cost-benefit analysis was conducted to estimate ratepayer impacts based on the reconstructed market outcomes. LEI staff submitted written testimony, as well as oral testimony.

Date:	2008
Location:	Canada
Company:	Private Client
Description:	Julia led a team that provided a comprehensive analysis of the proposed market power mitigation measures for Alberta's electricity market for a major utility. Julia and her team looked at various scenarios and presented the likely outcomes given various generation portfolio configurations under each proposal and whether these mitigation measures will result in the desired results. Led by Julia, the LEI staff made a case that more rigorous and robust approaches are needed than the proposed measures. Additionally, Julia's team conducted a comparative analysis of the procurement processes and compensation schemes of the different ancillary services products in eight markets, namely: New York, New England, Pennsylvania-New Jersey-Maryland, Texas, UK, Alberta, Australia, and Ontario. The results of this analysis were used to support the client in the Alberta's stakeholder process to redesign a system operator's procurement process

Date:	2007-2008
Location:	United States
Company:	Private Clients
Description:	over the course of 2007 and 2008, LEI prepared over a dozen MBR filings for various markets coming under the FERC's triennial schedule as established in Order 697

Date:	2006
Location:	United States
Company:	Oklahoma Municipal Power Authority
Description:	Julia concluded that the mitigation offer, as it was proposed, was inadequate in size and scope due to the potential for strategic behaviour and generation market power abuses. She argued that "if competitive harm created by the acquisition was to be reversed, transmission capacity upgrades were need to create sufficient competition to defeat the strategic bidding opportunities that Westar will obtain with its acquisition of the Spring Creek plant." (Docket No. EC06-48-000)

Date:	2006
Location:	United States
Company:	California Independent System Operator
Description:	Julia led LEI's advisory services to the California Independent System Operator, where she and her team devised an innovative approach for evaluating the economics, environmental, and siting costs and benefits of transmission (and generation investment). Building upon the traditional economic framework for cost-benefit analysis, the LEI team devised an approach to quantitative value the expected net benefits from various infrastructure projects, taking into account market uncertainties as well as the classic deregulated market coordination problem of planning for transmission give uncertain generation investment and vice versa. A scoring technique for environmental permitting and siting issues was also developed, in order to quantify the potential impact of the proposed project on the local environment and economy, as well as to measure the impact of such factors on the project timetable and eventual net benefits to society. Real option techniques were also considered in this engagement to assess the potential value of uncertainty and the benefits for delaying various investment strategies. The methodology was also expanded to handle the potential to evaluate numerous competing projects, in recognition of the fact that transmission and generation investments (and other potential investments) could be both complements and substitutes

Date:	2006
Location:	United States
Company:	Connecticut Department of Public Utility Control
Description:	Julia has evaluated measures needed to reduce Federally Mandated Congestion Charges ("FMCC") in Connecticut. Together with the LEI team she also performed an economic evaluation of the New England and Connecticut energy markets using LEI proprietary production cost model, POOLMod. Julia testified at the Connecticut Department of Public Utility Control ("DPUC") regarding the RFP process, RFP documentation, and contract template. Julia also testified on evaluation of project bids in comparison to anticipated market outcome. Julia's analysis supported hundreds of millions of dollars of investments.

Date:	2006
Location:	United States
Company:	Private Client
Description:	For an infrastructure fund, LEI used our propriety production cost simulation model to forecast electricity prices and generation from each plant. In addition, we provided capacity price forecasts for California based on the Resource Adequacy Requirement (RAR) at the system and local level.

Date:	2006
Location:	United States
Company:	Barrick Goldstrike Mines

Description:	Julia has written the report that served as an Addendum to the market power analyses that were filed with FERC in Docket No. ER05-665-001. The objective of this Addendum was to address the items requested by FERC in the deficiency letter issued on June 23, 2005 in this docket

Date:	2006
Location:	United States
Company:	California Energy Commission

Date:	2005
Location:	United States
Company:	Private Clients
Description:	Testimony at FERC on market power issues on behalf of intervener in proposed Exelon-PSEG merger per Section 203 of the Federal Power Act. In May 2005 Julia provided direct and supplemental testimony outlining key considerations relating to the potential for adverse competitive effects in light of the proposed merger and recommended additional mitigation measures to cure horizontal market power concerns through independent analysis of merger's impact on wholesale energy and capacity markets in PJM.

MARKET ANALYSIS

Date:	2013
Location:	United States and Canada
Company:	Private client
Description:	London Economics International LLC ("LEI") performed economic advisory in a matter relating to market design strategy for a large incumbent generator in Alberta. LEI performed a case study-oriented comparative review of energy-only and energy and capacity markets in North America and abroad, and take stock of lessons learned from other jurisdictions. LEI's work plan called for the simulation modeling of three forms of market design: an energy-only market, an energy and capacity market akin to Eastern US RTO markets, and a hybrid market with long term contracts and a spot market for capacity. The third phase involved the creation of a customized tool for future analysis, based on the simulation modeling results.

Date:	2013
Location:	United States
Company:	Private client

Description:	LEI was engaged by a Japanese research institute to research the environment for investment and financing of new generation in the US competitive electricity markets as well as the types of approaches used to manage investment risk. The LEI team researched the impact of market restructuring in the US on generation investment, methods for financing new generation, and analyzed policies promoting generation investment. LEI also performed four case studies on projects that were successfully financed and built in recent years, including assets in California (CAISO), Maryland (PJM), New York (NYISO) and Texas (ERCOT).

Date:	2013
Location:	United States
Company:	Duke-American Transmission Company
Description:	Julia was part of a team of economists that performed a macroeconomic analysis to estimate the local economic benefits accruing to taxpayers, residents, and businesses along the 800+mile route during construction of the Zephyr HVDC project, which runs from Wyoming to Colorado, Utah, and Nevada. LEI performed the analysis using the REMI P1+ model.

Date:	2013
Location:	United States
Company:	Private client
Description:	Julia led the preparation of a market study to support financing of a renewable generation portfolio in New England. The market analysis supported a successful multi-million dollar debt raise for the client.

Date:	2013 (ongoing)
Location:	United States
Company:	Entergy, Inc./Public Utility Commission of Texas
Description:	Julia and her team of economists were engaged by Entergy, Inc. to provide independent review and assessment of cost-benefit analysis related to termination of certain PPAs between Entergy Texas Inc. and Entergy Louisiana. LEI's assessment was requested by the Public Utility Commission of Texas, as follow on to previous consultative services that LEI has provided.

Date:	2013
Location:	United States
Company:	Private client
Description:	LEI was hired to review regulatory and market drivers of energy and capacity prices in PJM, and forecast prospective revenues of a portfolio of pumped storage and conventional hydro generation facilities offered by FirstEnergy, over a 20 year horizon.

Date:	2010 – 2013 (ongoing)
Location:	United States

Company:	Tres Amigas
Description:	Julia and her team assisted Tres Amigas LLC, a start-up company on the revenue forecasting and modeling for the second stage financing. The start-up company aims to develop, own and operate a unique three-way AC/DC transmission facility located in New Mexico. In 2010, for the feasibility analysis stage, LEI provided extensive transmission evaluation, financial modeling, price forecasting, and market analysis for the markets, including the Arizona/New Mexico/Southern Nevada sub region of the Western Electricity Coordinating Council, the Electric Reliability Council of Texas, and the Southwest Power Pool. LEI's analysis support over $15 million of development stage funding. LEI continues to serve as economic advisor to Tres Amigas, as it seeks debt and equity financing to support construction of Phase I.

Date:	2012-2013
Location:	United States
Company:	Pacific Gas & Electric
Description:	Julia and the LEI team served as the Independent Evaluator for PG&E Request for Offers for natural gas storage which was successfully concluded in January 2013. Julia reported on the RFO process and selection of winning bidder to the Peer Review Group and Energy Division staff at the California Public Utilities Commission ("CPUC").

Date:	2012-2013
Location:	United States/Europe
Company:	Private Client
Description:	Julia and the LEI team prepared a white paper outlining the concept of a Virtual Power Plant product and auction format, as part of a multi-consultant engagement in support of restructuring of the Greek power sector.

Date:	2012 (ongoing)
Location:	United States
Company:	Private company
Description:	Julia led a comprehensive ratepayer-focused cost-benefit study of integrating a remote service territory into a Northeast RTO's footprint. The cost-benefit analysis looked that at the long-run the benefits of joining an RTO versus the costs of new infrastructure that would be needed to accomplish the integration. Julia's analysis will be used with regulators and state policymakers to pursue integration and investment.

Date:	2012
Location:	United States
Company:	Private company

Description:	Julia managed a market study reviewing historical electric rates (and projecting forward electric rates) for large commercial customers in the New England market. The electric rates analysis was composed of a number of components, such as the commodity costs of electricity, compliance costs for certain state programs (like RPS), delivery charge for delivering electricity, and ancillary services and administrative supply charges. LEI created projection for each of these components and considered state retail sales requirements for renewables, etc.

Date:	2012
Location:	United States
Company:	NRG, Inc.
Description:	Julia led a team of economists to assess the wholesale power market impacts of the merger of NRG, Inc. and GenOn. LEI staff, under Julia's direction and guidance, performed Delivered Price Tests analysis for the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act and submitted extensive analysis to FERC in the summer of 2012. The Merger Application was successfully approved by FERC in December 2012. Subsequently, LEI assisted the client in preparation of the 205 market-based rate authority analysis.

Date:	2012 (ongoing)
Location:	Japan/United States
Company:	Private Client
Description:	For a Japanese client, Julia is leading a team to assess market opportunities for industry-scale battery storage technology in the US and selected European jurisdictions for energy arbitrage and ancillary services provision. Under this assignment, LEI modeled the operation regime of a battery operating in energy and ancillary services markets in order to monetize added revenues for a wind and solar generators. Findings and modeling results were analyzed and presented before the client's management team and were then deployed to develop strategy for marketing battery technology to renewable developers and utilities. Another objective of the project was to identify most suitable markets and products to optimize the strategy of the battery's market entry.

Date:	2012
Location:	United States
Company:	NRG, Inc.
Description:	Julia provided written testimony and oral testimony at the Connecticut Public Utility Regulatory Authority ("PURA") related to the market power consequences of proposed merger of NU-NSTAR.

Date:	2012
Location:	United States
Company:	Maine Public Utility Commission

Description:	Julia led a team of researchers at LEI in the preparation of a written report on the state of renewable portfolio standard ("RPS") requirements in Maine and regionally across New England. Julia also testified at the Maine legislature. The report was commissioned by the Maine Public Utility Commission to fulfill a statutory requirement to provide research on the issue of RPS and its impact on generators and consumers.

Date:	2010 – 2011
Location:	United States
Company:	Maine Public Utilities Commission
Description:	LEI advised Maine Public Utilities Commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report provided a 'strawman' recommendation for an effective cost allocation methodology, which was used by the Maine PUC to guide it in its filings at FERC related to Order 1000 and the preceding NOPR on the same issue.

Date:	2011
Location:	Japan
Company:	Private Client
Description:	For a Japanese client, LEI provided a study on electricity sector unbundling in the US. The study starts with an overview of the electricity sector unbundling in the US, including the history of restructuring and unbundling efforts, the categorization of unbundling, and the organizational impact of unbundling. Three case studies were also provided on specific unbundling experiences of TXU Corp., Commonwealth Edison, and Consolidated Edison.

Date:	2011
Location:	United States
Company:	Private Client
Description:	Julia led a modeling analysis, in which the market price impact of incremental wind resources was projected. LEI staff completed a simulation-based forecast of the New England system for a future test year (2015) with varying levels of wind generation. Using the multi-scenario approach, we then estimated the energy market price reductions across a range of incremental wind generation scenarios. The simulation modeling was further supplemented with statistical analysis. The one year analysis was also supplemented with sensitivities employing different baseline assumptions with respect to fuel prices.

Date:	2011
Location:	United States
Company:	Private Client

Description:	LEI performed a fifteen (15) year simulation analysis to estimate the market impacts resulting from a new transmission interconnection (covering the timeframe 2015-2029) and project the impact on Maine customers (including Northern Maine customers). LEI evaluated the market evolution with and without the interconnection and described the potential ramifications for purchasing electricity for Northern Maine customers. The analysis also estimated the potential impact on ratepayers from the re-allocation of the ISO-NE Pool Transmission Facility rate to incorporate the Northern Maine load and franchise area under a pro forma 10-year transitional agreement. LEI performed the modeling using our up-to-date ISO-NE simulation model (which covers the energy and capacity markets), extended to represent in detail the Maritimes control area.

Date:	2011
Location:	United States
Company:	Private Client
Description:	Evaluation of fair market sales value of a coal-fired unit in Arizona, as required by a lease that expires in 2015. Results from LEI's proprietary modeling tool, PoolMod, on market prices and dispatch were used as inputs in the financial model, which used discounted cash flow techniques. Two cases (Base Case and High Case) were created to develop a range of value with a weighted average point estimate. In addition to the discounted cash flow model, the market approach, which looks at comparable transactions, and the cost approach, which looks at the cost of building the same facility were considered.

Date:	2011
Location:	United States
Company:	Private Client
Description:	LEI supported the negotiation of fuel supply and energy sales agreements for a biomass to energy facility. In particular, LEI's analysis focused on the appropriateness and risk associated with price and cost escalation factors. Reviewed similar power purchase agreements and analyzed a suite of available indices.

Date:	2011
Location:	PJM
Company:	Private Client
Description:	Provided valuation services for a waste coal facility located in the Pennsylvania-New Jersey-Maryland ("PJM") regional market. Specific tasks consist of i) due diligence review of documents such as past financial statements, operational statistics report, fuel agreements and power purchase agreements ("PPA"); ii) forecasts energy and capacity prices in the PJM regional market; iii) create a pro forma financial model to evaluate the market value of the plant as of expiration of its PPA; iv) writing a final report documenting assumptions, methodologies used and modeling results.

Date:	2011
Location:	New England

Company:	Private Client
Description:	LEI prepared presentation material on the electricity market impacts and the benefits of Northern Pass Transmission project for New Hampshire and New England consumers. In addition, LEI staff assisted the client in preparation of an op-ed piece for dissemination to New Hampshire press outlets. LEI staff also attended an internal company meeting and testified on behalf of the client. Lastly, LEI staff assisted in the preparation for and attended the live New Hampshire Public Radio program "The Exchange" to discuss the benefits of the Northern Pass Transmission over the hour-long live show.

Date:	2011
Location:	USA
Company:	Private Client
Description:	LEI provided extensive late stage development due diligence for investor in four potential merchant transmission investments. LEI prepared three presentations analyzing four proposed merchant HVDC transmission projects across the US. Analysis included detailing the development roadmap for HVDC projects and the current status of the proposed projects, identifying potential competitive threats from other similar competing transmission lines and proposed local generation, and examining the renewable needs and willingness to pay of utilities in the "sink".

Date:	2010
Location:	Greece
Company:	Private Client
Description:	Market design in support of electricity sector restructuring in Greece, specifically consideration of alternatives to physical divestiture of generation assets. On behalf of PPC, the government-owned vertically integrated national utility, LEI examined the following options: virtual power plant ("VPP") auctions, contract for difference ("CFD") and physical energy swaps. In case study format, the various options were compared against the following criteria: instrument objective, contract structure, contract terms, sale platform, settlement structure and the extent of physical control right transfer. Real-world experience from France, UK, Belgium, Denmark, Netherlands, Australia, and Alberta (Canada) helped shape the discussion of comparative advantages and disadvantages, taking into account the unique concerns for Greek policymakers.

Date:	2010
Location:	Louisiana, USA
Company:	City of New Orleans
Position:	Co-Project Manager

Description:	Julia acted as manager for LEI's engagement with the City of New Orleans. LEI was engaged to act as the independent monitor for Entergy New Orleans' solicitation of a Third Party Administrator to implement and deliver conservation and demand management programs on behalf of the utility. LEI provided guidance to Entergy and the City on the development of the request for proposals, including mandatory requirements and commercial terms. LEI oversaw the bid receipt as well as the review and selection process. A final report was provided outlining LEI's opinion as to the fairness of the overall process.

Date:	2009
Location:	Canada
Company:	Private Clients
Description:	Julia prepared a market study of the Ontario electricity market for a major potential investor in Ontario's generation assets. This report contains an overview of the Ontario electricity market, including a description of market evolution, a summary of key institutions, regulatory and policy initiatives that have impacted the market landscape, and a long term projection for the market going forward.

Date:	2009
Location:	Canada
Company:	Private Client
Description:	Julia advised a major utility in Canada in its call for tenders strategy for procuring firm capacity over a long term horizon from neighbouring jurisdictions. Julia evaluated the opportunity for purchasing capacity from interconnected jurisdictions and devising a procurement that would efficiently overcome seams issues and market design issues that attach different counting and valuation methods for capacity across jurisdictions

Date:	2006
Location:	United States
Company:	California Energy Commission
Description:	LEI was contracted by CEC to study the capacity products that have been traded in other jurisdictions, and more broadly examine trading platforms that may be useful models for California if a voluntary trading mechanism was implemented to assist market participants in trading capacity to achieve compliance with Resource Adequacy Requirements. Additionally, LEI produced a report to cover the functional requirements for a bulletin board posting and trading platform for bringing buyers and sellers together and allow trading of the various capacity products supported by RAR in California, such as System RA Capacity and Local RA Capacity, and possibly some form of Import RA Capacity. We also covered the functional requirements for a tracking system, including title tracking, certification of transactions, and possibly, compliance filing

Date:	2005
Location:	United States
Company:	Private Client

Description:	Julia headed the analysis of long-term price forecasts and energy market dynamics for many of the regions in the US and Canada, including New England, Pacific Northwest, California, Alberta, Southwest Power Pool, SERC, the Midwest US (ECAR, MAIN, and MAPP), Maritimes, Ontario, New England, and PJM. In this practice area, she manages a team of economists that use a variety of modeling tools to forecast one-year to fifteen-year wholesale energy, capacity (where relevant), and market-based ancillary services price forecasts. As part of the modeling effort, LEI proprietary dispatch simulation model, POOLMod, as well as other tools that have been developed by LEI, such as CUSTOMBid, ConjectureMod, ViTAL, and LEI's real options spark-spread module. This type of modeling effort required detailed investigation of the micro and macro-economic issues facing these regional markets: demand profiling, growth forecasting, reserve margin and new entry activity assessment. Such analyses are used by clients in establishing market values for assets they have targeted to acquire, consideration of portfolio risk and exposure, and assessments of procurement opportunities. This same modeling has supported regulatory analysis of utility acquisitions and planning strategies, consideration on the impact of market rules and as "reservation prices" for sale processes.

Date:	2005
Location:	Canada
Company:	Alberta Department of Energy
Description:	As part of the LEI team, Julia managed the theoretical analysis and quantitative simulation modeling in the design and testing of recommended new regulatory regime. Analysis and recommendations will be presented to stakeholders in the spring of 2005.

Date:	2005-2006
Location:	United States
Company:	Texas Public Utilities Commission
Description:	In September 2005, Julia's proposal for pricing safeguards in the wholesale market, referred to as the Peaker Entry Test, was submitted to the Public Utility Commission of Texas as an alternate to the Commission staff's proposal initially under Project No. 24255 which was later moved to and renamed by the PUCT a Project No. 31972. In April 2006, the PUCT adopted a variant of this proposal for use as pricing safeguards – the Scarcity Pricing mechanism (as specified in the above mentioned project). Under Project No. 29042 in September 2005 Julia looked at the Pivotal Supplier Test and supplied a critique of the PUCT staff's initial market power mitigation proposal. In June 2005, Julia participated on panel discussing market monitoring issues, as well as market power safeguards for wholesale electricity markets. In 2004, she also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and discussed efficiency consequences of certain bidding behavior. She also prepared and filed comment testimony and quantitative analysis on questions of market definition and market integration for the Public Utility Commission review in Project No. 29042. In November 2005, by the PUCT decision, both, Project Nos. 24255 and 29042 were rolled into the Project No. 31972

Date:	2005-2006
Location:	United States
Company:	Connecticut Department of Public Utility Control
Description:	The Department of Public Utility Control retained the services of LEI to assist the DPUC in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and once again selected LEI in September 2005 to monitor the November 2005 auction for services in 2006. Julia led LEI's team in providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. In November 2004 and 2005, Julia filed an affidavit after completion of the procurement process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidder.

Date:	2005
Location:	United States
Company:	California Public Utility Commission
Description:	Julia served as an expert witness on economic issues related to pricing, investment signaling and data confidentiality in Resource Adequacy and Procurement Proceedings at the California Public Utility Commission in November-December 2005 on behalf of the California Energy Commission. Julia authored direct and rebuttal testimony on these issues and testified in San Francisco in late November 2005.

Date:	2005
Location:	Canada
Company:	Private Clients
Description:	In response to government proposed policies on what defined a "fair, efficient, and openly competitive" market, LEI prepared a detailed white paper and market analysis on the proposed market power tests to be added regulation, and specifically demonstrating the adverse effects of the 20% hard cap market share limit proposed by Department of Energy ("DOE"). White paper was filed as testimony with the DOE in their consultation on Section 6 of the Electric Utilities Act.

Date:	2005
Location:	United States
Company:	Private Client
Description:	Economic advisory on market power mitigation tests for a large US-based utility in the Southwestern part of the US, consulting on market design features related to a proposed nodal market, including most significantly the market power analysis framework. LEI proposed strategy and is assisting in the development of an implementation framework for the local market, including prepared reports for the market design team and state commission. In addition, the approach will be proposed for federal review at FERC.

Date:	2004-2005

Location:	United States
Company:	Private Client
Description:	Prepared and filed testimony and quantitative analysis on questions of market definition and market integration. In June 2005, Julia participated on a panel discussing market monitoring issues, as well as market power safeguards for wholesale electricity markets. In 2004, she also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and discussed efficiency consequences of certain bidding behaviour.

Date:	2004-2005
Location:	United States
Company:	Connecticut Department of Public Utility Control
Description:	In her affidavits in 2004 and 2005 before the Connecticut Department of Utility Control, Julia described the procurement processes of Connecticut Power and Light Company ("CL&P") TSO. Her testimony outlined what would be the best practice and procurement processes for DPUC to adopt in order to have the most efficient and competitive process which would result in the lowest price possible for the electricity consumers under CL&P's TSO.

Date:	2004 – present
Location:	United States
Company:	Numerous Clients – FERC
Description:	In support of numerous acquisitions by various Independent Power Producers and generators across the US, Ms. Frayer prepares and continues to be involved in expert testimony for Market-based Rate Authorization applications, Triennial Reviews, and Section 203 filings. All Market-based Rate Authorization applications to date have been successfully accepted by FERC.

Date:	2004
Location:	Canada
Company:	Private Client
Description:	For a major Canadian utility, Julia undertook a comprehensive market assessment of the New England REC markets, and specifically the Massachusetts and Connecticut markets, under three different scenarios, the status quo, with the utility's resource commercialization schedule, and assuming sporadic participation by the utility.

Date:	2004
Location:	United States
Company:	Private Clients

Description:	Using LEI's proprietary simulation model of electricity wholesale markets in ISO New England, LEI forecast future cash flows for a portfolio of electricity generation assets and applied the net present value analysis to evaluate the portfolio's economic value under different potential future market conditions. This analysis supported the investment fund's decision to acquire and hold the generation portfolio's distressed debt.

Date:	2002
Location:	United States
Company:	Private Client
Description:	LEI was engaged by a large industrial customer to help review of power purchasing options at one of its Southeastern facilities over the next three years. We assessed the probability of a supply interruption over the next three years due to the state of the transmission system in this region. We also assessed the facility's options for purchasing power for this load in the wholesale market.

Date:	2001
Location:	United States
Company:	Private Client
Description:	LEI conducted an indicative valuation of a proposed new transmission line, known as the International Transmission Line. We forecasted the revenues associated with the project and combined this revenue forecast with the estimated costs of the project to arrive at an estimate of the net present value of the project and return on investment.

SPEAKING ENGAGEMENTS:

When	Description
Jan 11, 2013	Julia Frayer "Merchant Transmission: Planning and Development and Lessons Learned from North America", Integrated Transmission Planning and Delivery, Imperial College - Workshop for OFGEM, London, United Kingdom
Sep 5, 2012	Julia Frayer and Shawn Carraher "Demand for wind in New England: an economist's perspective", AWEA Regional Wind Energy Summit, Portland, Maine, USA
May 22, 2012	Julia Frayer, "Cost effective procurement of Renewables to Meet Policy Requirements", NECPUC Symposium, Rockport, Maine, USA
Mar 16, 2012	Julia Frayer, Shawn Carraher, and Yifei Zhang, "Best Practices for Transmission Asset Valuation", Transmission Grid Conference, London, United Kingdom
Oct 10, 2011	Julia Frayer "How effective is US technology policy on clean energy." 30th USAEE/IAEE North American Conference, Washington, DC, USA
Jun 21, 2011	Julia Frayer "Are Markets Ready for New Energy Storage Technologies?" 34th IAEE, Stockholm, Sweden
Jun 7, 2010	Frayer, Julia, Furhana Husani, and Yunpeng Zhang "Long Term Market Impact of Demand Response" 33rd IAEE International Conference, Rio de Janeiro, Brazil
Jun 21-24, 2009	Frayer, Julia, Zvika Neeman, and Matthew Wittenstein "Applications of Information Policy Principles from Auction Theory in the Deregulated Electricity Market" 32nd IAEE International Conference, San Francisco, California

Jun 10, 2005	Frayer, Julia "Prepared Presentation of Julia Frayer for Market Monitoring and Surveillance in the context of Market Design." Panelist, PUCT Workshop for Project #28500, Austin, Texas
Jan 27, 2005	Frayer, Julia "Written Statement of Julia Frayer for the January 27th 2005 Technical Conference in Docket RM04-7-000" Panelist, FERC Technical Conference, Washington D.C.
Nov 24, 2004	Frayer, Julia "Competitive procurement options for Ontario's LDCs" Speaker, APPrO 2004 Conference, Toronto, Ontario (Canada)
Nov 2004	Frayer, Julia, Nazli Uludere, and Sam Lovick "Beyond market shares and cost plus pricing: designing a horizontal market power mitigation framework for today's electricity markets." *Electricity Journal*
Mar 30, 2004	Frayer, Julia "The World Changed on August 14th: the (Second) Great Northeast blackout." Chairman of Panel Session, Electric Power Conference 2004, Baltimore, Maryland
Mar 31, 2004	Frayer, Julia "Alternative to LMP pricing for transmission: a case study of the ICRP approach used by National Grid Company in the UK." Speaker, Electric Power Conference 2004, Baltimore, Maryland
Mar 12, 2003	Frayer, Julia "Big ticket leasing - what next for the future?" Panelist, Big Ticket Leasing 2003, London (United Kingdom)
Nov 28, 2001	Frayer, Julia "Evaluating the Electron Highway" Speaker, IPPSO 2001 Conference, Richmond Hill, Ontario (Canada)
Nov 2001	Frayer, Julia and Nazli Uludere "What is it worth? Application of real options theory to the valuation of generation assets" Electricity Journal
Jul 15 2001	Goulding, A.J., Julia Frayer, Jeffrey Waller "X Marks the Spot: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly*
Mar 22, 2001	Frayer, Julia "How much is it worth? Applying real options valuation framework to generation assets" Speaker, Electric Power 2001, Baltimore, Maryland
Mar 1, 2001	Goulding, A.J., Julia Frayer, Nazli Z. Uludere "Dancing with Goliath: Prospects After the Breakup of Ontario Hydro" *Public Utilities Fortnightly*

LANGUAGES:

Language	Reading	Speaking	Writing
English	Native	Native	Native
Russian	Fluent	Fluent	Fluent

EXECUTIVE BIOGRAPHIES

James M. Coyne, Senior Vice President, is an industry expert who provides financial, regulatory, strategic, and litigation support services to clients in the power and gas utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, cross-border trade, rate and regulatory policy, capital cost determinations, valuations, fuels and power markets. He is a frequent speaker and author of numerous articles on the energy industry and regularly provides expert testimony before federal, state and provincial jurisdictions in the U.S. and Canada. He testifies on matters pertaining to the cost of capital, capital structure, business risk, alternative ratemaking mechanisms and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

James D. Simpson, Senior Vice President, has over 30 years of experience with regulatory relations, regulated pricing and business strategy; he has held senior executive positions at a natural gas utility and an entrepreneurial company providing a proprietary service to generating companies. As Chief Operating Officer for a major New England gas company, Mr. Simpson was responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning. His responsibilities in other positions have included business development, pricing strategy, regulatory affairs, analysis and planning. Mr. Simpson also held staff and director level positions at the Wisconsin Public Service Commission and the Massachusetts Department of Public Utilities; he has an M.S. in Economics from the University of Wisconsin and a B.A. in Economics from the University of Minnesota.

Melissa F. Bartos, Assistant Vice President, is a financial and economic consultant with more than fifteen years of experience in the energy industry. She has conducted comprehensive demand forecast analyses including data collection and validation; model building using various statistical and econometric approaches, and developing presentations, reports and testimony to communicate results. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos has also provided expert testimony regarding natural gas demand forecasting issues. Ms. Bartos previously consulted with Reed Consulting Group and Navigant Consulting, Inc.; she has an M.S. in Mathematics (Statistics) from the University of Massachusetts at Lowell, a B.A. from the College of the Holy Cross in Worcester, MA, and is a member of the American Statistical Association.

CUSTOMIZED IR PLAN

Summary

1. Enbridge Gas Distribution ("Enbridge", or the Company) continues to be one of the fastest growing utilities in North America. With a strong focus on customer satisfaction and safety, the Company continues to provide exceptional value to customers, businesses and communities within its franchise area. As the result of consistent growth over many years, combined with aging infrastructure and increasing distribution safety expectations, the Company is now faced with significant challenges. Substantial investments well in excess of historic levels need to be made in the distribution system in order to maintain safety, reliability, and growth.

2. Among the key challenges to be addressed in the coming years are increased capital spending and activity requirements for System Integrity and Reliability projects and programs, to minimize the risks in the operations of an aging distribution infrastructure. These risks are real, and must be addressed. Enbridge's required increasing level of System Integrity and Reliability work arises from recognition of these risks, and from awareness and reaction to recent industry safety events, changes in regulations and Enbridge's ongoing review of processes and decision criteria to maintain a safe distribution system. While the planned activities will increase capital spending, the resulting safety enhancements will benefit ratepayers and the public through continued safe, reliable and secure service.

3. The GTA reinforcement project is critical to maintaining continued reliable service within Enbridge's main operating area. Over the past 20 years, Enbridge has added around 800,000 customers, largely in and around the GTA. The GTA reinforcement project is a direct response to the growing need for gas distribution by GTA customers, and will allow

access to lower cost gas supplies for all Enbridge customers. The GTA project is the largest expansion project that the Company has undertaken for many years, and the associated costs further contribute to increased capital spending requirements.

4. Over the coming years, Enbridge will also continue its efforts to enhance the customer experience across all interactions – on the phone, on the web, and in the community. The Company has a strong customer focus and will provide transparent performance measurement information to the Board and stakeholders with respect to customer satisfaction, operations, safety and financial results.

5. Enbridge is firmly focused on providing affordable, safe and reliable natural gas service. This Customized IR plan allows for this to continue over the coming years. The Customized IR plan supports necessary investment in system safety and reliability, and will result in customer bill increases well below inflation.

6. Customer bills are expected to increase well below inflation from 2014 to 2016, with an annual average increase of about 0.5%. Over the full five year IR term, increases are forecast to be less than 1.5% per year on average.

7. This Application is Enbridge's proposal for a 2nd Generation Incentive Regulation ("IR") or Customized IR plan for five years from 2014 to 2018, to address and accommodate the challenges described above and throughout the evidence. In its original filing, the Company proposed a Customized IR plan with a five year term, including an update of capital spending requirements for 2017 and 2018 to address the difficulty in forecasting such costs at this time. Now, having considered concerns raised about the plan to revisit costs midway through the IR term, Enbridge has updated its Customized IR Plan to allow for all aspects of 2014 to 2018 Allowed Revenue to be set in this proceeding.

Witnesses: R. Fischer
M. Lister

8. Enbridge's proposed updated Customized IR plan fixes the Company's allowed distribution revenue amounts ("Allowed Revenue") for 2014 to 2018 based upon the Company's forecast costs, inclusive of productivity savings, for each of those years. This Updated Customized IR plan, which no longer requires that Enbridge's 2017 and 2018 Capital Budgets be determined midway through the IR term is made possible by using the 2016 Capital Budget (except for the removal of $8.1 million in costs related to WAMS which will not be included for 2017 and 2018) as a reasonable forecast of the Company's 2017 and 2018 capital spending requirements. As this was the same approach used in the original filing to set "Preliminary" Allowed Revenue amounts for 2017 and 2018, there is no effect on the numerical evidence and forecasts of 2017 and 2018 Allowed Revenue that results from the updated Customized IR plan. Under this approach, Enbridge is at risk (except within two specified areas of spending described below) for any additional capital spending requirements in 2017 and 2018 other than those identified within the 2016 Capital Budget.

9. This Application will set final rates for 2014, and preliminary rates for 2015 to 2018. The preliminary rates for 2015 to 2018 will be subject to annual adjustments primarily to reflect updated volume and gas cost forecasts for those years.

10. In creating the Customized IR plan, Enbridge evaluated its 1st Generation IR plan and took into account its current circumstances and expected business needs over the coming years. Through this process, Enbridge determined that it cannot continue with a similar I-X framework as existed for the 1st Generation IR term. As described below, a number of changed circumstances in its operating environment present Enbridge with hurdles too large for an I-X framework to accommodate. Among these are extraordinary capital spending pressures related to safety and integrity issues, very large capital projects related to system supply and work asset management, growing depreciation costs and uncertainty about future capital spending requirements.

11. Enbridge's proposed Customized IR plan meets the Board's (and the Company's) objectives for an IR plan. It will benefit customers by ensuring safe and reliable service and enabling necessary safety and reliability spending. Customers and the Company will benefit from the establishment of rates for a five year period which will produce fair and predictable rates while reducing regulatory burden. The Customized IR plan embeds demonstrated productivity in both Operating and Maintenance ("O&M") and capital cost forecasts, and includes a number of incentive mechanisms that are designed to effect additional efficiencies that will be sustained beyond the end of the IR term.

12. The proposed Customized IR plan is also informed by the "Custom IR" option presented in the OEB's recent "Renewed Regulatory Framework" Report ("RRF Report"), and with IR plans used in other jurisdictions. In keeping with the expectations set out in the RRF Report, the proposed Customized IR plan creates "an appropriate alignment between a sustainable, financially viable [gas] sector and the expectations of customers for reliable service at a reasonable price".[1]

13. The key components of Enbridge's Customized IR Plan are set out in the following table:

	Components of IR Plan	**Details**
Items to be determined in the 2014 proceeding (EB-2012-0451)	Allowed Revenue amounts for 2014 to 2018	To be determined by summing together, for each year, the appropriate forecast level of operating costs, depreciation costs, taxes and cost of capital. These annual amounts are what Enbridge will be entitled to collect in rates each year.

[1] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, Ontario Energy Board, October 18, 2012, p. 1.

	Components of IR Plan	Details
	Volumes and Gas Cost related impacts for 2014	To be determined using the proposed updated Heating Degree Day ("HDD") methodology, as well as a gas volume forecast using existing methodologies for average use and large volume forecasts. Current gas cost forecasts to be used.
	Final Rates for 2014	Designed to allow full recovery of the 2014 Allowed Revenue.
	Preliminary Rates for 2015 to 2018	Designed to allow full recovery of the 2015 to 2018 Allowed Revenue amounts, based upon current forecast of volumes and current forecast of gas costs. The preliminary rates are included to reflect current projections of the approximate impact of the IR plan in those years, but will be subject to update and approval in annual Rate Adjustment proceedings for 2015 to 2018.
Items subject to adjustment in 2015 to 2018	Average number of unlocks, volumes and gas costs related impacts, and amounts related to Pension, DSM and Customer Care costs	In advance of each year, Enbridge will provide: (i) updated forecasts of unlocks (active billed customers) using the customer addition forecasts approved in the 2014 and 2016 proceedings and other updated economic inputs; (ii) forecast volumes (applying the existing methodologies for HDDs, average use and large volume forecasts); and (iii) updated gas supply plan and gas costs. The updated data will be applied to the approved Allowed Revenue for each year to derive final rates for 2015 to 2018. The approved Allowed Revenue amounts each year will be updated to include recent forecasts of amounts related to Pension/OPEB, DSM and Customer Care/CIS costs.
	Earnings Sharing Mechanism ("ESM")	To share weather normalized earnings between ratepayers and the Company on a 50/50 basis on earnings more than 100 basis points above Allowed ROE (calculated each year using the Board's ROE formula). The ESM will provide incentives for Enbridge to find further efficiencies and shares those benefits with rate-payers.

Witnesses: R. Fischer
M. Lister

	Components of IR Plan	Details
	Sustainable Efficiency Incentive Mechanism (“SEIM”)	To provide incentives for Enbridge to produce sustainable efficiencies that will survive beyond the end of the IR plan term.
	Deferral and Variance Accounts	All existing deferral and variance accounts will be maintained (along with a small number of additional accounts) and a new variance account for the GTA project. There will also be a new variance account for 2017 and 2018 to capture differences in Allowed Revenue related to relocations projects and replacement mains projects resulting from pipeline inspections (including in-line inspections) and maximum operating pressure testing.
Items subject to extraordinary adjustment	Z-factor	Allowance for recovery of unexpected cost increases or cost decreases with a revenue requirement impact of more than $1.5 million per year that are outside of management control. Updated wording for Z-factor eligibility is proposed, clarifying what was included in Enbridge’s 1st Generation IR plan.
	Off-Ramp	Enbridge shall file an Application for review of the IR plan if its normalized earnings during any of the first 4 years of the IR plan are more than 300 basis points different from the Allowed ROE (calculated using the Board’s 2009 ROE Formula).
Other Components	Performance Measurement	To track the Company’s productivity initiatives, and operational and financial performance and benchmark against a peer group. Operational and financial performance will be reported at the end of the IR term, addressing a variety of performance metrics including customer satisfaction and a number of safety-related indicators. Tracking of productivity initiatives will be reported annually. Regular reporting through ESM proceedings and RRR filings will continue.

Witnesses: R. Fischer
M. Lister

14. The table below shows the anticipated rate and bill impacts for average residential customers over the five years of the Customized IR plan term.

Estimated Rate and Bill Impacts including SRC rate rider credit

With the GTA Project	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Variance (2013 - 2018)**	**Average (2014 - 2018)**
Change in Rates*								
Annual % Change		-0.7%	2.1%	4.6%	2.4%	2.5%		2.2%
Total Bill for Average Residential Customer ($)**	867	837	851	879	896	926	59	
Annual % Change		-3.5%	1.7%	3.3%	1.9%	3.3%		1.4%
Without the GTA Project	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
Change in Rates*								
Annual % Change		-0.7%	1.7%	2.1%	2.4%	2.5%		1.6%
Total Bill for Average Residential Customer ($)**	867	837	849	862	879	909	42	
Annual % Change		-3.5%	1.4%	1.5%	2.0%	3.4%		1.0%

* Does not include SRC rider credit
** Includes SRC rider credit

15. As seen above, customer bills are expected to increase by only $12 over the first three years of the IR term, an annual average increase of about 0.5% per year. Over the full five year term, customer bills will increase by around $59, an average increase of about 1.4% per year.

16. As can be seen in the table, rates are forecast to decline in 2014, and then to increase over the next years. The average annual rate increase for residential customers from 2014 to 2016 is 2.0%. When one removes the impact of the major GTA reinforcement project that will be completed in 2015, the average annual rate increase is 1.0%. Over the full five year

term, the average annual rate increase is around 2.2% (with an average annual rate increase around 1.6% without the impact of the GTA project).

17. When considering the bill impact of the rate changes summarized above, one must also take account of the bill savings that will be realized through the Customized IR term. First, Enbridge's proposal to credit customers with more than $250 million in accumulated depreciation costs related to Site Restoration costs over five years will have a significant reduction effect on customer bills. Over the 2014 to 2016 period, this is expected to reduce the average residential customer bill by about $25 per year. Second, when the GTA reinforcement project is completed, customers are expected to see substantial savings on gas costs. This is expected to reduce the average residential customer's bill by $5 and $28 in 2015 and 2016, respectively.

18. In the sections that follow, this evidence will:
    a. Set out the objectives to be met for an IR plan, as articulated by the OEB, and from the perspective of the Company;
    b. Explain why Enbridge's Customized IR plan is a multi-year incentive regulation model;
    c. Highlight the key issues and challenges that Enbridge faces in the coming years;
    d. Outline the regulatory alternatives considered in determining this Customized IR plan;
    e. Provide details about the proposed Customized IR plan;
    f. Describe how the proposed Customized IR plan meets the objectives of the OEB and the Company; and
    g. Summarize the outcomes from the application of Enbridge's proposed Customized IR Plan for 2014 to 2018, including the benefits and impacts to Enbridge ratepayers.

Witnesses: R. Fischer
M. Lister

A. Objectives of an Incentive Regulation Plan

19. Enbridge's proposed Customized IR plan will be appropriate if it meets the objectives of the OEB and also takes account of the Company's own objectives. Success in this regard will mean that the public interest is protected, and it will also allow the Company to meet its business objectives.

20. The Board's Natural Gas Forum ("NGF") laid the groundwork for the development of gas utility incentive regulation. The NGF Report (Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005) describes the plan for incentive regulation as adopting "the best aspects of both the COSR (cost of service regulation) and PBR approach." The NGF Report (at pages 2 to 3) also established criteria which the IR plans must satisfy including:
    a. establish incentives for sustainable efficiency improvements that benefit customers and shareholders;
    b. ensure appropriate quality of service for customers; and
    c. create an environment that is conducive to investment, to the benefit of customers and shareholders.

21. These objectives should be viewed alongside the Board's statutory obligations in relation to the regulation of gas distributors (set out at section 2 of the OEB Act), which include the following objectives:
    a. to protect the interests of consumers with respect to prices and the reliability and quality of gas service;
    b. to facilitate rational expansion of transmission and distribution systems;
    c. to promote energy conservation and energy efficiency;
    d. to facilitate rational development and safe operation of gas storage; and

e. to facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

22. Taken together, the Board's objectives make clear that a gas distributor's IR plan must:
    a. ensure appropriate reliability and quality of service (including safe operations);
    b. protect customers from unreasonable price impacts;
    c. promote energy conservation and efficiency;
    d. protect the financial viability of the distributor and allow for appropriate investments to be made; and
    e. provide a framework that incents the distributor to implement sustainable efficiency improvements.

23. Recently, the Board issued its RRF Report (Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012), setting out the Board's policies to support an electricity distribution network that is efficient, reliable, and sustainable and provides value to customers.

24. While the RRF Report is directed at electricity distributors, there are elements of the Electricity Distribution Rate-Setting policies section of the Report that are instructive to gas distributors. Of key importance is the Board's recognition of the challenges faced by some distributors because of significant capital spending requirements which may be "lumpy" in nature. To accommodate those challenges, the Board will provide options to electricity distributors to use different rate-setting methods that are best suited to their circumstances. Two of the three methods approved for electricity distributors ("incremental capital module" within 4th Generation IR and "Custom IR") allow for recovery of capital expenses that are outside of the distributor's base revenue requirement, and would not otherwise be recoverable during an IR term. This is a clear recognition that meeting the Board's goal of

ensuring reliable, sustainable distribution service may require high levels of capital spending, and this should be accommodated within an IR framework.

25. From all of the foregoing, Enbridge understands that the Board expects an IR plan for a natural gas distributor to cover several years and allow for appropriate rate adjustments, while ensuring that quality of service and necessary investment are maintained. The Board also expects an IR plan to provide a distributor with the opportunity and incentive to seek sustainable productivity gains.

26. While acknowledging the importance of the Board's objectives, the Company is also mindful of meeting the objectives that it has set for its own operations. These include the following:
    a. Continued commitment to safety – the safety of Enbridge's customers, the public and its employees is Enbridge's top priority;
    b. A focus on improving the customer experience across all interactions – on the phone, on the web, and in the community; and
    c. Improving productivity in all of the Company's operations.

27. From Enbridge's perspective, it is important that its Customized IR plan allow for the above objectives to be met. The IR plan must accommodate necessary investments in infrastructure and system integrity work to ensure continued safe, reliable and secure service. Given the significant symmetry between the OEB's and Enbridge's objectives, it appears clear that these goals also fit within the Board's expectations.

B. <u>Enbridge's Customized IR Plan is a Multi-year Incentive Regulation Model</u>

28. EGD's Customized IR plan is designed as a multi-year incentive regulation model with a revenue cap that is informed by forecast cost elements that include significant expected productivity savings that will have to be achieved by the Company.

Witnesses: R. Fischer
M. Lister

29. The introduction and demonstration of productivity into the forecast cost elements that make up the annual Allowed Revenue amounts is discussed at Exhibit A2, Tab 1, Schedule 2, and within the detailed evidence about Enbridge's forecast Capital and O&M budgets for 2014 to 2016. These budget amounts, inclusive of productivity savings, will be used to create annual Allowed Revenue amounts for 2014 to 2016. The Allowed Revenue amounts for 2017 and 2018 will be set using forecast costs that are based upon the 2014 to 2016 budgets. Once the Allowed Revenue amounts are set, there will be no annual adjustments, other than for customer unlocks, related revenue impacts, gas costs, gas in storage carrying costs, related income tax impacts, cost elements subject to previously determined variance agreements, and any eligible Z factor items.

30. The result is that the Company is "at risk" for costs over the projected Allowed Revenue amounts and is incented to manage costs within that level, as there is no sharing for cost overruns. Unlike an annual Cost of Service ("COS") approach, this will create fixed Allow Revenue amounts that are decoupled from actual costs over the IR plan term. The Company will not have recourse to request rate relief over the plan term absent a 300 basis point shortfall against allowed ROE which is unfound in COS regulation.

31. A further incentive arises from the fact that Enbridge will not be entitled to recover the cost consequences of any capital spending above the levels approved in this proceeding. Therefore, should Enbridge spend above the approved level over the first three years of the Customized IR plan, then it will have to wait until rebasing in 2019 to recover any associated costs. It should be noted that the GTA project is subject to variance account treatment, and new variance accounts will exist for 2017 and 2018 to capture differences in Allowed Revenue related to capital spending on relocations project and on mains replacement

requirements identified through pipeline inspection and maximum operating pressure testing activites.

32. The Earnings Sharing Mechanism ("ESM") within the Customized IR plan allows for sharing with customers of efficiency improvements that result in lower costs during the IR term. This creates a potential ratepayer benefit not available in COS. Moreover, the fact that the Company is entitled to retain a fair portion of earnings above allowed ROE acts as an incentive for Enbridge to find and implement cost saving programs and initiatives.

33. In addition, the Customized IR plan includes a new incentive feature, referred to as the Sustainable Efficiency Incentive Mechanism ("SEIM"), which is detailed at Exhibit A2, Tab 11, Schedule 3. The SEIM will further incent the Company to create sustainable efficiencies during the IR term by removing any disincentive to defer productivity spending in the later years of the IR plan, resulting in reduced rebasing year costs and beyond. The SEIM will reward the Company for implementing such programs, and ratepayers will benefit from increased focus by the Company on programs and activities that result in long-term sustainable cost savings.

34. There are few differences between the Customized IR plan, and Enbridge's 1st Generation IR plan. The main difference relates to how the Allowed Revenue amounts are initially set. As explained later in this document, the capital costs component of the Allowed Revenue amounts for 2014 to 2016 takes account of Enbridge's extraordinary requirements over that period. Even so, it does include productivity savings. The O&M component of Allowed Revenues within the Customized IR plan is largely consistent with Enbridge's 1st Generation IR plan. This is confirmed by Concentric Energy Advisors, Inc. ("Concentric"), who have concluded that Enbridge's O&M budgets for 2014 to 2016 are actually lower than would be

expected under a conventional I-X type of IR plan. Given that the budgets will change at the same rate for 2017 and 2018, that finding holds true for the entire IR term.

35. The Company has worked with two different experts in the building and evaluation of the Customized IR plan.

36. Concentric undertook various financial analyses of Enbridge's circumstances and the Customized IR plan, and evaluated other IR plan options. Concentric's conclusion, as seen in their report (at Exhibit A2, Tab 9, Schedule 1) is that the proposed Customized IR plan allows Enbridge's particular circumstances to be appropriately met in a way that provides Enbridge with a built-in challenge for continued productivity improvement.

37. London Economics International, LLC ("LEI") provided information in its report (at Exhibit A2, Tab 10, Schedule 1) about the "Building Blocks" IR ratemaking model used in the United Kingdom and Australia. LEI explained that the Building Blocks IR model has been found to work well in other jurisdictions, as it motivates productivity, allows for extraordinary capital requirements spending to be accommodated, and protects against sudden true-ups in rates. LEI observed that the Customized IR model uses much of the same approach as the Building Blocks model. Taking the learnings from the Building Blocks IR model into account, LEI concluded that Enbridge's Customized IR plan will serve ratepayers and the Company well.

C. <u>Key Issues and Challenges faced by Enbridge in the Coming Years</u>

38. Enbridge's Customized IR plan must be responsive to the operating and business challenges that the Company expects to encounter during the coming years.

39. The main challenges that Enbridge will face in the coming years include the following:
   a. Capital spending pressures to maintain a safe and reliable system;
   b. Other spending pressures; and
   c. Productivity challenges.

Each of these items is highlighted below, and addressed in more detail in the evidence.

a. Capital spending pressures to maintain a safe and reliable system

40. The most significant issue facing Enbridge through the coming years is increasing capital spending requirements. While many of these requirements are clear and can be forecast at this time, others are more uncertain. This uncertainty increases as the forecast period gets longer.

41. In developing the Customized IR plan, Enbridge's most significant forecasting challenge has been the uncertainty of safety and integrity spending requirements. This can be seen within the Company's Asset Plan, which sets out the Company's capital plans for distribution assets over ten years and has been developed as an important internal planning tool. The 2013 to 2022 Asset Plan is filed at Exhibit B2, Tab 10, Schedule 1. In the process that underlies the Asset Plan, the Company made a concerted effort to identify, assess and prioritize risks to its distribution system. Through this approach, Enbridge will develop and implement programs to monitor, repair or replace components of the system as required. There are, however, a significant number of potential risks that have been identified, but about which Enbridge does not have sufficient information to determine the extent and timing of the required remedial action.

42. In cases where risks require further analysis before the extent of mitigation can be determined, targeted risk studies have been identified. These studies will result in additional

programs or projects to address risks in future years. The costs associated with such additional programs or projects are not known and therefore cannot be included as part of Enbridge's Capital Budget presented in this Application.

43. In other cases, Enbridge has identified programs or projects to be undertaken, without full knowledge of the scope of the associated work. It will only be when the study or initial work is done that the Company will know the scope and timing and cost of further additional work. The costs associated with such additional programs or projects are similarly not part of Enbridge's Capital Budget presented in this case.

44. The uncertainty around Enbridge's Capital Budget requirements, especially in the System Integrity and Reliability area, is detailed within Exhibit B2, Tab 1, Schedule 1.

45. At the time that Enbridge filed this Application, the Company determined that the uncertainties elaborated on above make forecasting of capital costs for more than three years unacceptably unpredictable. Enbridge noted that, if it were not for this high level of uncertainty associated with a forecast of Enbridge's capital spending requirements beyond three years, Enbridge's preference would be to present five year cost forecast information, to allow for Allowed Revenue amounts for each year of the IR term to be set at this time. The Company concluded at the time that the Application was filed that because the level of capital spending requirements is unknown, it would impose unfair risks on the Company and on ratepayers to set Allowed Revenue amounts based upon 2017 and 2018 capital budget requirements at this time. If the Allowed Revenue is set too high for those years, based on speculative information, that would be unfair to ratepayers. Conversely, setting the Allowed Revenue too low for those years would be unfair to Enbridge.

Witnesses: R. Fischer
M. Lister

46. The uncertainty of capital spending requirements beyond 2016 led Enbridge to create three-year Capital Budgets, for 2014 to 2016, rather than five year Capital Budgets.

47. While Enbridge's original plan was to file updated Capital Budgets for 2017 and 2018 midway through the Customized IR term, the Company understands that there is resistance to that approach. A concern has been raised that cost forecasts should not be revisited in the middle of the IR term. Taking that concern into account, Enbridge has updated its Customized IR plan, so that Allowed Revenue for all five years of the IR term will be set in this proceeding. As explained within Exhibit B2, Tab 1, Schedule 1, Enbridge has decided to use the 2016 Capital Budget (except for the removal of $8.1 million in costs related to WAMS which will not be included for 2017 and 2018) as the basis for forecasts of capital spending requirements for each of 2016, 2017 and 2018. This takes into account the fact that Enbridge is not able to produce a detailed line-by-line capital budget forecast for 2017 and 2018, and instead uses 2016 Capital Budget as the best representation of the Company's capital spending needs in the following two years. The updated approach will enable Allowed Revenue amounts for all five years to be set in this proceeding. It should be noted that this updated approach does not result in any change to the numbers presented to build up Allowed Revenue amounts for 2017 and 2018, because the same approach that was proposed to set "Preliminary" Allowed Revenue amounts for those years is now used to set "Final" Allowed Revenue amounts for those years.

48. Enbridge's forecast capital spending requirements for 2014 to 2016 were determined though a rigorous process that examined all proposed areas of capital spending, and then prioritized and paced the associated spending. This has involved a careful examination and prioritization of spending requirements to ensure focus only on high priority projects. The intention of this process was to identify the level of spending necessary to maintain a safe and growing distribution system, while determining what items could be delayed, phased or

dismissed. Explanation of the intense capital budgeting process that resulted in the 2014 to 2016 Capital Budget is set out at Exhibit B2, Tab 1, Schedule 1.

49. The net result of the asset planning and capital prioritization processes is the 2014 to 2016 Capital Budget that is described in the evidence and summarized in the table below. As can be seen, Enbridge will have to accomplish a much higher level of activity in the future relative to past levels of activity. The costs associated with the required capital spending activities are what led Enbridge to its Customized IR plan. As described below (under the heading "Regulatory Alternatives Considered"), the Customized IR plan is the appropriate approach to accommodate Enbridge's capital spending requirements.

Summary of Capital Expenditures

	Col 1	Col 2	Col 3	Col 4
($Millions)	Board Approved Budget 2013	Forecast 2014	Forecast 2015	Forecast 2016
Customer Related Distribution Plant	123.0	119.0	126.8	137.1
NGV Rental Equipment	0.3	3.4	3.6	3.7
System Improvements and Upgrades	192.8	243.2	247.8	242.2
General and Other Plant	47.6	56.3	52.7	48.4
Underground Storage Plant	22.4	21.9	15.7	10.5
Sub total "Core" Capital Expenditures	386.1	443.8	446.6	441.9
Work and Asset Management System (WAMS)	0.5	36.3	25.7	8.1
Leave to Construct - Major Reinforcements	63.3	202.2	359.7	-
Total Capital Expenditures	449.9	682.3	832.0	450.0

50. The increased level of Enbridge's required capital spending activity during the 2014 to 2016 period is largely driven by four factors: (i) safety and integrity spending, (ii) major projects, (iii) customer growth, and (iv) relocation requirements. Each is described briefly below, and in more detail in the B2 series of exhibits.

Witnesses: R. Fischer
M. Lister

(i) *safety and integrity spending*

51. The first factor relates to higher levels of safety and integrity spending, which is largely driven by an ageing infrastructure.

52. Recent events in the natural gas industry, such as the San Bruno explosion in September 2010, the Philadelphia explosion in January 2011, and the Allentown explosion in February 2011, have tragically confirmed the importance of public safety in gas distribution operations. These incidents are discussed in more detail within the System Integrity and Reliability Capital Budget evidence, at Exhibit B2, Tab 5, Schedule 1. One of the responses to these and other incidents has been the acceleration of changes and additions to codes and regulations (in addition to changes and additions that were already being seen). Another response has been an increase in activity undertaken by operating companies to reduce the probability of any reoccurrences of these tragic incidents.

53. As described in the System Integrity and Reliability Capital Budget evidence (at Exhibit B2, Tab 5, Schedule 1), Enbridge has identified a significant number of programs, studies and initiatives that must be undertaken. Some of these continue historic activities, while others are new.

54. The System Integrity and Reliability Capital requirements include: (i) replacing existing assets as they reach the end of their useful life; (ii) conducting engineering studies and analysis to improve the Company's understanding of the condition and operating limits of specific critical classes of assets and undertaking required work identified as a result; (iii) complying with all applicable rules and regulations related to system integrity and safety; (iv) improving distribution asset records to reduce operational risk; and (v) implementing enhanced monitoring and system control programs to reduce the impact of unplanned system interruptions.

Witnesses: R. Fischer
M. Lister

(ii) major projects

55. The second main driver of increased capital spending requirements over coming years relates to major projects that must be undertaken. The key examples here are the GTA and Ottawa Reinforcement projects, and the new Work and Asset Management System ("WAMS").

56. The GTA and the Ottawa Reinforcement projects are each the subject of separate Leave to Construct Applications with the OEB (GTA EB-2012-0451 and Ottawa Reinforcement EB-2012-0099). The description of the purpose, need and timing of each project is set out in the Leave to Construct Applications. In this Application, Enbridge is seeking to include the cost consequences of each project into rates, once the projects come into service.

57. The proposed WAMS project is a requirement for the future operations of the Company servicing its customers. The WAMS project is fully described in Exhibit B2, Tab 8, Schedule 2. The need for this project stems from technology drivers and the need to maintain support of the primary work and asset management functions.

58. The primary driver for the WAMS project is the coming end of the Accenture Services Agreement which was part of the EnVision Project that the Board approved in its 2004 decision in RP-2003-0203. The Company has decided that a more cost effective solution to the services approach that currently provides Work and Asset Management services would be to implement an in-house IT system. Timing is also driven by technology obsolescence of the decade old solution.

(iii) customer growth

59. The third main driver of capital spending requirements over the coming years relates to ongoing demands arising from continued customer growth. These costs continue to

increase, because the material and installation costs associated with adding new customers are going up, while the number of customer additions continues to be robust.

60. Based on the forecast numbers and location of the expected demand in new customers, the Company expects a rise in construction of new mains, as well as targeted reinforcement of existing pipeline systems to support the related growth in gas load.

(iv) *relocation requirements*

61. The final main factor contributing to increased capital spending requirements over the coming years is relocation requirements. With the Pan-Am games coming to Toronto in 2015, the City is undertaking an expansion of infrastructure improvements, which is beyond the control of management. At the same time, franchise agreements demand that the Company comply with relocation activity as directed by the municipalities. In addition to increased activity in preparation for the Pan-Am games, Ottawa, Toronto and areas around the GTA are moving forward with Light Rail Transit plans that will also have a significant impact on the level of relocation activity required in the next several years. This item is discussed at Exhibit B2, Tab 4, Schedule 1.

b. Other costs pressures

62. In addition to the significant capital spending cost pressures described above, the Company also faces operating cost pressures in the coming years.

63. The largest of Enbridge's annual costs are its O&M costs. The Company has worked with representatives of each business area to create an O&M budget for 2014 to 2016, followed by a top-down review by management to confirm the reasonableness of resulting budgets, in order to determine the necessary level of O&M spending over that period.

Witnesses: R. Fischer
M. Lister

64. The resulting 2014 to 2016 O&M Budget restricts cost increases to less than 2% per year (on average). That is shown in the following Table, which is further explained within the O&M Budget Overview evidence (Exhibit D1, Tab 3, Schedule 1)

Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2013 Board Approved to 2016 Budget

Line No.	Categories ($ Millions)	Col. 1 Board Approved 2013	Col. 2 Budget 2014	Col. 3 Budget 2015	Col. 4 Budget 2016	Col. 5 2014 vs. 2013	Col. 6 2015 vs. 2014	Col. 7 2016 vs 2015
1.	Customer Care/CIS Service Charges	$89.4	$92.6	$96.5	$100.4	$3.2	$3.9	$3.9
2.	Demand Side Management ("DSM") [(1)]	31.6	32.2	32.8	33.5	0.6	0.6	0.7
3.	Pension and OPEB Costs	42.8	37.2	33.8	30.9	(5.6)	(3.5)	(2.9)
4.	Regulatory Cost Allocation Methodology("RCAM")	32.1	35.3	34.0	33.8	3.2	(1.3)	(0.2)
5.	Other O&M	219.2	228.0	231.5	241.0	8.8	3.5	9.5
6.	Total Net Utility O&M Expense	$415.1	$425.3	$428.5	$439.5	$10.2	$3.2	$11.0

[(1)] 2013 DSM reflects the final Board approved amount of $31.6M

65. In fact, as explained in the O&M Budget Overview evidence and the Concentric report (Exhibit A3, Tab 9, Schedule 1), the level of increase in Enbridge's main O&M costs over the 2014 to 2016 period is less than would be the case under a traditional I-X ratemaking model. Enbridge's proposal for 2017 and 2018 is to maintain the same rate of change of the O&M expenses (except for CC/CIS, DSM and pensions/OPEBs, each of which have their own Board-approved cost setting approach) as is approved for 2014 to 2016.

66. Maintaining the O&M Budget at this level will require the Company to find significant operating efficiency savings and productivity, as underlying costs are expanding at a higher rate, and the volume of required work is increasing. Keeping the rate of growth of these costs to around 2% or less for five years will be very challenging.

Witnesses: R. Fischer
M. Lister

67. Another cost pressure relates to the fact that the Company's depreciation expense is forecast to grow, on average, almost 6% annually over the coming years. This is a function of past capital investments and increasing capital expenditures. Depreciation represents almost a third of the estimated Allowed Revenue, but is growing about twice as fast as the remaining cost elements. Assuming that most other cost elements are growing at close to inflation, revenue necessarily would need to grow at a rate greater than inflation for the Company to earn the Allowed Return. As explained at Exhibit A2, Tab 1, Schedule 3, the cost pressures from depreciation expense are not accommodated within a traditional I-X IR model, and are a main contributor to Enbridge's decision to proceed with this Customized IR model.

c. Productivity Challenges

68. A third significant challenge faced by Enbridge in the development of its Customized IR plan relates to productivity. This issue is discussed in detail at Exhibit A2, Tab 1, Schedule 2. Key aspects are discussed below.

69. On the one hand, the Company understands the Board's objective that utilities will achieve sustainable productivity gains within an IR term. On the other hand, though, the Company believes that it is limited in the productivity opportunities that are available, as a strong cost performer that has just completed a five year IR term with very modest rate increases.

70. Taking this into account, the Company has created a Customized IR plan that includes productivity savings that must be achieved in order to meet 2014 to 2016 forecast cost levels, as well as incentive mechanisms within the IR plan itself.

71. As seen in the O&M Budget (described in the D1 series of exhibits) and the Capital Budget (described in the B2 series of exhibits), the Company has created its cost forecasts by

committing to challenging productivity goals. This represents a key and significant risk the Company is undertaking. That is, the Company recognizes that it is taking a significant risk in being able to achieve these productivity goals, let alone anything beyond.

72. As discussed in the evidence at Exhibit B2, Tab 1, Schedule 1, Enbridge completed forecasts of its capital spending requirements for each year of the three year period from 2014 to 2016. Enbridge conducted a careful review of these capital spending requirements and prioritized its projected capital spending requirements in each of the three years to ensure that its proposed capital spending is pared down to include only work that is essential and prudent.

73. In relation to the O&M budget, the Company has undertaken an appropriate process to identify a level of spending that is reasonable and required, and represents a productive and efficient level of spending. As seen at Exhibit D1, Tab 3, Schedule 1, the 2014-2016 O&M Budget is substantially lower than the grass-roots budget that was originally prepared and proposed to Enbridge's management.

74. The fact that there are limited productivity opportunities available to Enbridge beyond what is included within the filed budgets can be seen in two ways.

75. First, updated benchmarking analysis comparing Enbridge's O&M costs with industry peers shows that Enbridge continues to be a top performer. This is seen in the Concentric benchmarking analysis, within their report at Exhibit A2, Tab 9, Schedule 1.

76. Second, the Company asked Concentric to compare Enbridge's O&M budget for 2014 to 2016 against the budget level that would be expected under an I-X framework that applied only to O&M expenses. To undertake this analysis, Concentric determined and forecast the

appropriate I factor (inflation) that should apply to Enbridge's O&M costs, and determined the appropriate X factor (productivity offset) to apply to Enbridge's O&M costs. Concentric's conclusion is that Enbridge's O&M Budget (for those items within the Company's control) is $12 million less than would be expected under an I-X approach. Concentric's closing remark in this regard (at Page 49) is that "The $12 million in cumulative savings …. can be viewed as additional productivity flowing through to customers, beyond the productivity that would be built into a PFP I-X formula". This supports a conclusion that the filed 2014-2016 O&M Budget (and the rate of change within that budget) includes productivity savings beyond the expected level, and this will benefit ratepayers.

77. Taken together, the items above make clear that Enbridge has limited opportunities for incremental productivity gains in the coming years (beyond the savings already reflected in the filed O&M and Capital Budgets and the 2013 Settlement Agreement), meaning that the pending cost pressures described above will challenge the Company to produce productivity gains elsewhere.

D. <u>Regulatory Alternatives Considered In Determining This Customized IR Plan</u>

78. Enbridge considers that its 1st Generation IR Plan was successful. Ratepayers have enjoyed steady, predictable rates and safe, reliable distribution service. Consumers also benefited from earnings sharing through the ESM that was part of the 1st Generation IR plan. However, as explained, Enbridge faces new and different challenges in the coming years, as compared to its experience during the 1st Generation IR term.

79. Over the past year, Enbridge has evaluated how to adapt its 1st Generation IR Plan to meet the challenges that Enbridge will face during its Customized IR term. As a result of its evaluation efforts, Enbridge has concluded that a traditional I-X IR framework is not

appropriate. With that determination, the Company has looked at alternative IR models, and has created this Customized IR plan.

80. In the course of these efforts, Enbridge has consulted with stakeholders individually and as a group to keep parties apprised of the issues that the Company faces in creating a 2nd Generation IR plan and to gain stakeholders' feedback and insights. One of the issues raised through that process was that stakeholders expect a five year term for the IR plan.

81. In response, Enbridge took steps to modify its Customized IR Plan. In its original filing, the Company proposed a Customized IR plan with a five year term, including an update of capital spending requirements for 2017 and 2018 to address the difficulty in forecasting such costs at this time. Now, having considered concerns raised about the plan to revisit costs midway through the IR term, Enbridge has updated its Customized IR Plan to allow for all aspects of 2014 to 2018 Allowed Revenue to be set in this proceeding.

a. Inappropriateness of an I-X Framework for Enbridge's Circumstances

82. In a COS framework, all else equal, rates are designed to result in neither a revenue sufficiency nor deficiency, ensuring that all the elements that contribute to the determination of revenue requirement are recovered. The utility's costs are reviewed closely before the regulator approves them for recovery through rates. This gives an opportunity for the utility to justify these costs. Under this framework, the regulatory lag is minimal and provides the utility a reasonable opportunity for timely recovery of investments and to earn its allowed rate of return.

83. With traditional I-X IR plans, the review of costs is removed from the annual regulatory process and the utility is expected to manage its business within the confines of a formula-driven adjustment mechanism over three years or more. This is problematic in an

environment where capital spending pressures, the associated growth in depreciation expense and other cost elements driven by capital investments more than outweigh the growth in revenue from an I-X formula.

84. While the escalation factor in IR plans that use an I-X mechanism do allow for a certain level of net capital additions, the revenue increase resulting from the adjustment mechanism also needs to recover growth in cost of capital, tax, depreciation and O&M expenses.

85. Designing an adjustment mechanism that provides a reasonable opportunity for a utility to recover the costs on a timely basis and earn a fair return is a challenge in an I-X regulatory plan when it is experiencing non-steady state capital requirements. The extraordinary operating cost pressures described above also pose a problem. Taken together, the magnitude of the required spending increases means that they cannot be accommodated within an I-X mechanism.

86. In order to determine whether and how the Company could continue for a 2nd Generation IR term using a plan similar to the 1st Generation IR plan, Enbridge conducted a series of financial analyses. These analyses are presented within Exhibit A2, Tab 1, Schedule 3.

87. Financial analyses were completed to assess how Enbridge would fare in coming years if the 1st Generation IR plan (which used an I-X framework in a revenue cap per customer model) was applied to several different three year scenarios (three year scenarios were chosen to align with the term of the Company's Capital Budgets). Among other things, these scenarios assumed that the GTA and Ottawa reinforcement projects would be treated as cost pass-throughs, and that the depreciation cost reduction would be effective. In each of these scenarios, Enbridge assumed that the I-X escalator would equal 2.5%. In that regard, Enbridge used the analysis undertaken by Concentric which concluded that the

appropriate "I" factor to apply to Enbridge's costs would equal 2.5% and the appropriate "X" factor would be 0%. The assumed "I" factor represents the average forecast composite inflation rate for 2014 to 2016 that applies to Enbridge's costs and that, according to Concentric, would be the appropriate "I" factor to use in an I-X mechanism (this is discussed in Concentric's report at Exhibit A2, Tab 9, Schedule 1). The assumed "X" factor is taken from Concentric's TFP analysis and recommendation contained in their report.

88. Enbridge's analyses indicated that the Company requires a different model from its 1st Generation IR plan.

89. To confirm the conclusion that Enbridge requires a different IR model for its 2nd Generation term, financial analysis was also completed to determine the level of I-X that would be required to allow Enbridge to achieve the forecast Allowed ROE in the coming years. This analysis looked at a variety of scenarios, including an approach where the revenue requirement amounts associated with the GTA and Ottawa projects were "passed through" as Y factors. Each of the scenarios assumed levels of capital and O&M spending consistent with Enbridge's cost forecasts.

90. As can be seen within Exhibit A2, Tab 1, Schedule 3, each of these scenarios requires a level of I-X of at least 3.4% to allow Enbridge to achieve the forecast Allowed ROE in the coming years. That confirms why a traditional I-X IR model will not work in Enbridge's circumstances: because a traditional I-X model would not provide an adjustment factor at or near that level. This is seen in: (i) the fact that the average adjustment factor that applied during Enbridge's 1st Generation IR plan was 0.9%; and (ii) Concentric's finding that an appropriate adjustment factor in a traditional I-X IR model for a utility in Enbridge's circumstances would be 2.5%. ROE deficiencies would be exacerbated were the Board to determine that the appropriate "I" and "X" should be less than that proposed by Concentric.

Witnesses: R. Fischer
M. Lister

b. Considerations for Enbridge's next Incentive Regulation plan

91. Having determined that a different IR model is required, Enbridge considered what options exist. A key expectation of IR is for utilities to maintain a safe and reliable distribution system and have a reasonable opportunity to earn their Allowed ROE (thus maintaining a financially viable gas distribution industry and meeting the fair return standard) while being incented to find further efficiencies through an appropriate incentive mechanism.

92. With that in mind, Enbridge considered alternative IR plans that could be used to allow the utility to recover its prudent and necessary costs and have the opportunity to earn a fair return.

93. In this regard, Enbridge considered the Board's RRF Report, and its description of a "Custom IR" plan. The RRF Report indicates that a "Custom IR" approach is most appropriate where a distributor has "significantly large multi-year or highly variable investment commitments that exceed historical levels". That is a fair description of Enbridge's situation. In evaluating the "Custom IR" approach, the Company took account of the Board's recognition that utilities facing extraordinary capital spending requirements will need a different form of IR model.

94. As seen in the various aspects of the proposed Customized IR plan, the Company has customized the rate-setting method being proposed to fit its particular circumstances. At a high level, though, Enbridge's Customized IR plan is aligned with the "Custom IR" model in that it creates a multi-year rate trend based upon Enbridge's forecasts of costs and revenues, and applies benchmarking and productivity analysis to confirm the reasonableness of the results.

Witnesses: R. Fischer
M. Lister

95. Enbridge also received assistance from LEI in reviewing and considering IR plans used in other jurisdictions that set rates by assessing forecast costs and revenues for a number of future years. As can be seen in LEI's evidence, found at Exhibit A2, Tab 10, Schedule 1, a "Building Blocks" approach, which is similar to the Customized IR plan that is being proposed by Enbridge, is used in the United Kingdom and Australia.

96. The foregoing has led Enbridge to propose a Customized IR plan that develops Allowed Revenue based on forecasts of cost of capital, depreciation, tax and operating costs. This Customized IR plan provides an opportunity for all stakeholders to review all cost elements, yet also recognizes that productivity needs to be embedded in the cost elements and that incentives must exist for the utility to find further efficiencies and share the benefits of those efficiencies with ratepayers.

E. <u>The Customized IR Plan Proposal</u>

97. All of the items described above have contributed to the design of Enbridge's proposed Customized IR plan. Earlier in this exhibit, Enbridge presented a table setting out the key components of its proposed Customized IR plan. Further detail for each of these items is provided below.

a. Allowed Revenue

98. Allowed Revenue to be recovered in rates in each year of the Customized IR term will be determined as the sum of the annual forecast required revenue for the cost of capital, depreciation, tax and operating expenses. These items will be pre-determined within this Application for each year of the IR term, and not subject to change, except as described below.

99. The Allowed Revenue build-up in this Application for 2014 to 2016 is based on the following detailed forecasts for each of 2014, 2015 and 2016:

a. An O&M Budget, inclusive of productivity savings, which has been created through the budget process described above;
b. A depreciation forecast, which is based on forecast gross plant and gross plant additions (as driven by forecast future capital expenditures in the Capital Budget), net of retirements and inclusive of the impact of the change to the CDNS approach to determine SRC funding requirements (see below for description of this item);
c. A cost of capital forecast, which is determined as: (i) the forecast rate base each year (starting with the 2014 opening rate base as determined in the 2013 Rate Case Settlement Agreement) multiplied by the equity ratio, multiplied by the forecast ROE for the subject year; plus (ii) the forecast costs of debt;
d. A tax forecast, which is based on current tax rates for income taxes and municipal taxes and fees; and
e. A forecast of Other Revenues that acts as an offset to the costs detailed above.

100. Further description of the process to set Allowed Revenue amounts is set out at Exhibit A2, Tab 3, Schedule 1. The Allowed Revenue amounts for 2014, 2015 and 2016 are set out at Exhibit F1, Tab 1, Schedule 2.

101. The same approach is used to build-up Allowed Revenue for 2017 and 2018. The difference is that certain of the forecasts that build up to the Allowed Revenue amounts use the 2014 to 2016 budgets as their starting points. The Allowed Revenue amounts for 2017 and 2018 will be set based on the following:

a. O&M Budgets, inclusive of productivity savings, which are determined by applying the average rate of change in such budgets between 2013 and 2016 to the prior year's budget;

Witnesses: R. Fischer
M. Lister

b. A depreciation forecast, which is based on forecast gross plant and gross plant additions (as driven by forecast future capital expenditures in the Capital Budget), net of retirements and inclusive of the impact of the change to the CDNS approach to determine SRC funding requirements. The 2017 and 2018 Capital Budgets used in connection with this component will be set at the same level as 2016 (except for the removal of $8.1 million in costs related to WAMS which will not be included for 2017 and 2018);

c. A cost of capital forecast, which is determined as: (i) the forecast rate base each year multiplied by the equity ratio, multiplied by the forecast ROE for the subject year; plus (ii) the forecast costs of debt;

d. A tax forecast, which is based on current tax rates for income taxes and forecasts that 2017 and 2018 municipal taxes will increase at a rate that is equal to the average rate of such taxes from 2013 to 2016; and

e. A forecast of Other Revenues, fixed at the 2016 level, which acts as an offset to the costs detailed above.

102. Further description of the process to set Allowed Revenue amounts is set out at Exhibit A2, Tab 3, Schedule 1. The Allowed Revenue amounts for 2017 and 2018 are set out at Exhibit F1, Tab 1, Schedule 2 and Exhibits F6 and F7.

b. Volumes and Gas Costs for 2014

103. Enbridge's forecast volumes for 2014 will be determined using an updated Heating Degree Day ("HDD") methodology, (as described at Exhibit C2, Tab 1, Schedule 2*)* and applying the existing methodologies for average use and large volume forecasts (as described at Exhibit C2, Tab 1, Schedule 3*)*.

104. The Company's evidence includes a gas cost forecast for the years from 2014 to 2016, based upon current volumetric projections for the term (see Exhibits D3/D4/D5, Tab 3, Schedule 1). Only the 2014 gas cost forecast and 2014 volume forecast are subject to approval in this proceeding. For future years, the gas cost forecasts filed in this Application include assumptions around updated opportunities arising from the completion of the GTA project.

c. Final Rates for 2014

105. Using the established volumes, revenues and gas costs for 2014, the Company's evidence sets out rates designed to recover the 2014 Allowed Revenue. The final 2014 rates set out in this Application (Exhibit H1, Tab 1, Schedule 1) are to be implemented as of January 1, 2014. Further details of the 2014 Rate Adjustment proposal within this Customized IR plan are set out at Exhibit A2, Tab 2, Schedule 1.

d. Preliminary Rates for 2015 to 2018

106. In order to provide an indication of the magnitude of changes in rates that will be effective each year from 2015 to 2018, Enbridge's evidence sets out the rates that would be required to recover the 2015 to 2018 Allowed Revenue amounts, using forecasts of volumes and the preliminary forecast of revenues and gas costs for 2015 to 2018.

107. The estimated rates presented in this Application for 2015 to 2018 (Exhibit H3, Tab 1, Schedules 1 and 2*)* will be subject to change for those years, to reflect updated forecasts for volumes, revenues and gas costs.

108. Enbridge's preliminary rates for 2017 and 2018 will be prepared by using the 2016 forecasts of volumes, revenues and gas costs, applied to the preliminary Allowed Revenue amounts for 2017 and 2018.

Witnesses: R. Fischer
M. Lister

e. Annual Adjustments for 2015 to 2018

109. Enbridge believes that in order to fully incent productivity improvement and cost savings in its Customized IR plan, there should be an attempt to minimize the number and amount of elements under review for annual adjustment. On the other hand, there are certain volume, revenues and gas-cost related aspects of Enbridge's rates that are difficult to predict and largely outside of the Company's control. As was the case within its 1st Generation IR term, Enbridge proposes to update those items annually, so that the Customized IR plan does not result in either Enbridge or ratepayers gaining or losing from flawed forecasts.

110. Enbridge's proposal is that, in advance of each subsequent year (2015 to 2018), the Company will provide updated forecasts of volumes (using an updated unlocks forecast based on the pre-set customer additions forecast and other economic data and applying the approved methodologies and processes for HDDs, average use and large volume forecasts), revenues and gas costs. The updated data will be applied to the approved final Allowed Revenue amount for each year to derive final rates for each year from 2015 to 2018.

111. Additionally, there are certain items that have previously been approved by the Board which ought to be updated each year, so that rates properly recover the associated costs (and no more or less). To accomplish this outcome, the annual adjustment process will update the forecasts associated with pension/OPEB, DSM and Customer Care/CIS costs, such that the Allowed Revenue for the subject year includes the most up to date amounts.

112. The intention is to make the rate adjustment process as mechanical as possible, by simply applying approved and established methodologies to update forecasts related to items that are subject to uncontrollable change during the Customized IR term. Details about the

mechanics of the annual Rate Adjustment process are set out at Exhibit A2, Tab 3, Schedule 1.

f. Deferral and Variance Accounts

113. As set out at Exhibit D1, Tab 8, Schedule 1*,* Enbridge proposes to carry forward all currently established deferral and variance accounts from 2013 through to the end of the Customized IR term.

114. In addition, Enbridge also proposes a new variance account associated with the GTA project to ensure that Enbridge collects no more or less than the prudent costs of that project, as discussed at Exhibit D1, Tab 8, Schedule 2.

115. Further, Enbridge proposes two new variance accounts, to be in place for 2017 and 2018, to track differences in Allowed Revenue associated with two areas of capital spending which are beyond Enbridge's control (relocations, and replacement mains requirements identified through pipeline inspections (including ILI) and MOP activities)). For each of these areas, Enbridge proposes variance accounts for 2017 and 2018, through which the Allowed Revenue implications of spending that is significantly higher or lower than included within the budget would be recoverable from ratepayers. Details of the proposed variance accounts can be found at Exhibit D1, Tab 8, Schedule 6. It should be noted that the variance accounts are only operative, though, if the actual Allowed Revenue consequences of required additional spending in either area are more than $1.5 million above the forecast amount for that area (which is the same threshold as applies for Z factors).

g. Earnings Sharing Mechanism (ESM)

116. Enbridge believes that an ESM within the Customized IR term is appropriate to provide assurances that cost forecasts and the resulting Allowed Revenue are reasonable. That is, if Enbridge's cost forecasts are too high, then the utility would be the net beneficiary absent any ESM. The Company also recognizes that with an IR framework, there is a desire to incent a utility to find efficiencies. Therefore, Enbridge believes that an ESM that provides benefits to both the Company and ratepayers will create an incentive to push the Company's cost control efforts.

117. The ESM proposed for Enbridge's Customized IR term (as described at Exhibit A2, Tab 7, Schedule 1*)* will share net weather normalized earnings above the Formula ROE output that applies in that year, as follows:

   a. 0 up to 100 bp to the shareholder; and
   b. greater than 100 bp, 50/50 between ratepayers and shareholder.

118. In calculating the Formula ROE output for any given year, Enbridge will use the Board's ROE formula from the EB-2009-0084 Cost of Capital report.

h. Sustainable Efficiency Incentive Mechanism (SEIM)

119. The Customized IR plan includes a new incentive feature, referred to as the Sustainable Efficiency Incentive Mechanism (SEIM), which is detailed at Exhibit A2, Tab 11, Schedule 3. The SEIM will further incent the Company to create sustainable efficiencies during the IR term by removing any disincentive to defer productivity spending in the later years of the plan, resulting in reduced costs at the rebasing year and beyond. The SEIM will reward the Company for implementing such programs, and ratepayers will benefit from increased focus by the Company on programs and activities that result in long-term sustainable cost savings.

Witnesses: R. Fischer
M. Lister

i. Off-Ramps

120. Enbridge proposes to maintain the same Off-Ramps in its Customized IR plan (as described in Exhibit A2, Tab 6, Schedule 1*)* as existed in the 1st Generation IR plan. Specifically, if in any of the first four years of the IR term there is a variance greater than 300 basis points in weather normalized utility earnings, above or below the amount calculated annually by the application of the Board's 2009 ROE Formula, Enbridge shall file an application with the Board, with appropriate supporting evidence, for a review of the Customized IR plan.

j. Z-Factor

121. Enbridge proposes that the Customized IR Plan should continue to include a Z-factor clause for unexpected cost increases or cost decreases that are outside of management control. The threshold for Z-factor treatment (revenue requirement of $1.5M) is proposed to be the same as during the 1st Generation IR term. Enbridge is proposing some clarifying wording changes to the description of the Z-Factor clause from what was included within the 1st Generation IR plan. Enbridge's Z-factor proposal can be found at Exhibit A2, Tab 4, Schedule 1.

k. Performance Measurement

122. As part of this Application, Enbridge is also proposing a performance measurement framework to track and report the Company's productivity initiatives and operational performance. The results of this tracking will be reported at the end of the Customized IR term. Annual reporting of productivity initiatives during the Customized IR term will be provided through the RRR filings and the annual ESM Applications. Details of Enbridge's performance measurement proposal are set out at Exhibit A2, Tab 11, Schedule 2.

Witnesses: R. Fischer
M. Lister

123. Enbridge believes that the performance measurement framework will help to align stakeholder and utility views. Reporting will promote the engagement of stakeholders in the issues that face the utility, and measure and monitor the outcomes that can be influenced by management. The proposal to create a performance management reporting framework is also in keeping with the RRF Report for electricity utilities.

F. The Customized IR Plan Proposal meets the OEB's objectives

124. The proposed Customized IR plan fits with the OEB objectives for an IR plan, and also meets the Company's own objectives.

125. Fundamentally, the Customized IR plan provides Enbridge with the ability to address "must-do" work to maintain the safety and reliability of its distribution system. As explained, the magnitude of this work means that it could not otherwise be accommodated in an I-X framework. The fact that Enbridge has prioritized spending and removed costs and activities that are not immediately necessary protects customers from unreasonable price increases. Customers will also benefit from continued quality service, and performance measurement reporting.

126. Enbridge's proposed Customized IR plan also provides appropriate incentives for Enbridge to implement incremental sustainable efficiency improvements (to the extent that is possible). Under the proposed plan, once the forecast Allowed Revenue amounts have been approved, Enbridge takes the risk during the IR term that it will be able to operate at those levels and is thus incented to provide service at lower costs. To the extent that such efforts are successful, ratepayers will share in the savings through the ESM. There are further incentives for Enbridge to find and implement lasting productivity savings, as a result of the SEIM. In any case, ratepayers will benefit from the fact that productivity

assurances are already built into the underlying cost estimates and ongoing spending will be monitored to ensure that it is being optimized.

127. The certainty provided through Enbridge's proposed Customized IR plan will benefit all stakeholders and will assist the Company in meeting its own objectives (commitment to safety, assisting customers to get value for energy dollars and delivering shareholder value through the opportunity to earn Allowed ROE).

G. <u>Implementation and Impacts of the Customized IR Plan</u>

128. The implementation of the Customized IR plan will benefit Enbridge and its ratepayers. The Customized IR plan will accommodate Enbridge's capital spending requirements, and this will enable necessary safety and reliability improvements to be made to Enbridge's distribution system. All parties will benefit from sustained productivity improvements that continue after the IR term.

129. The forecast rate impacts resulting from the Customized IR plan over the 2014 to 2018 period, as set out at Exhibit H , are reasonable.

130. As discussed above, customer bills are expected increase well below expected inflation from 2014 to 2016, and are forecast to be 1.4% or $12 higher by the end of 2016 than today. The rate and bill impacts for 2014 to 2018 are set out in the following table (reproduced from the Summary section above).

Estimated Rate and Bill Impacts including SRC rate rider credit

With the GTA Project	2013	2014	2015	2016	2017	2018	Variance (2013 - 2018)	Average (2014 - 2018)
Change in Rates*								
Annual % Change		-0.7%	2.1%	4.6%	2.4%	2.5%		2.2%
Total Bill for Average Residential Customer ($)**	867	837	851	879	896	926	59	
Annual % Change		-3.5%	1.7%	3.3%	1.9%	3.3%		1.4%
Without the GTA Project	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
Change in Rates*								
Annual % Change		-0.7%	1.7%	2.1%	2.4%	2.5%		1.6%
Total Bill for Average Residential Customer ($)**	867	837	849	862	879	909	42	
Annual % Change		-3.5%	1.4%	1.5%	2.0%	3.4%		1.0%

* Does not include SRC rider credit
** Includes SRC rider credit

131. In total, therefore, the estimated average bill impact for a typical Enbridge residential system supply customer over the first three years of the Customized IR plan term will increase approximately $4 per year. This equates to an annual average bill increase of approximately 0.5% over the first three years. Over the full five year term, the expected annual bill increase will be less than $10 per year - approximately 1.4% per year over the five years.

Witnesses: R. Fischer
M. Lister

IR PLAN PRODUCTIVITY

1. The Customized Incentive Regulation ("IR") plan proposed by Enbridge Gas Distribution Inc. ("EGD" or the "Company") is based on a five year forecast of costs, and includes other forecast elements such as cost of capital and tax rates. Two /u major differences between EGD's proposed plan and a traditional cost of service model are 1) the incorporation of incentives designed to encourage the utility to find and implement further sustainable efficiencies during the IR term; and 2) the inclusion of anticipated productivity savings in the forecast cost elements.

2. Productivity embedded in EGD's forecasts of O&M costs is demonstrated in three ways. First, the traditional budgeting process was modified to ensure that budget owners' forecasts for O&M did not exceed specified inflation targets which the Company can demonstrate include productivity. Secondly, total O&M budget costs were measured against an 'Inflation less Productivity' factor, which was recommended and forecast by Concentric Energy Advisors, Inc. ("Concentric"). Lastly, specific productivity metrics for O&M overall costs were benchmarked against an industry peer group to demonstrate that efficiency is reflected in the cost forecasts.

3. EGD's 2014 to 2016 budget forecasts for O&M and capital were determined through a comprehensive and iterative budgeting process designed to ensure that the cost forecasts incorporate productivity with a resulting Allowed Revenue envelope that will provide a significant challenge for the Company to operate within. The process, as described in detail within Exhibit B2, Tab 1, Schedule 1 and Exhibit D1, Tab 3, Schedule 1, was completed over many months and involved the application of

Witnesses: A. Mandyam
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inflation growth targets that reflect embedded productivity and a capital prioritization and scheduling process, including the application of risk tolerance criteria and probability assessment, to determine the minimum level of capital spend required in each year of the IR term.

4. Concentric was asked to develop and recommend an appropriate inflation index and Partial Factor Productivity ("PFP") X factor for O&M. The resulting I-X factor was used by Concentric to determine the amount of productivity beyond industry norms that is embedded in EGD's forecast for O&M for 2014 to 2016 as determined by the budgeting process. The results of that analysis confirmed that productivity is embedded in the forecast O&M Budget. This is set out in the Concentric Report, filed at Exhibit A2, Tab 9, Schedule 1.

5. Benchmarking analysis determined that EGD is operating as a top quartile performer for a number of productivity metrics, confirming both O&M and capital spending has been planned incorporating productivity and efficiency. This is set out in the Concentric Report, filed at Exhibit A2, Tab 9, Schedule 1.

6. The Customized IR plan proposed by EGD also includes a proposal for productivity tracking and performance measurement during the IR term, including reporting on benchmarking at the end of the IR term. Although EGD operates as a highly efficient performer compared to the North American peer group, the Company is committed to seeking out and reporting on future sustainable efficiencies. EGD will also share any benefits obtained above a certain level, through an Earnings Sharing Mechanism ("ESM"), which has been carried forward from EGD's 1st Generation IR plan. The Company is further incentivized to deliver sustainable efficiencies

through the term of the Customized IR through the Sustainable Efficiency Incentive Mechanism (“SEIM”), described in Exhibit A2, Tab 11, Schedule 3.

7. The Company’s Customized IR plan was informed by the Custom IR method outlined in the Ontario Energy Board’s Renewed Regulatory Framework for Electric Distributors developed in 2012 and other similar IR models, often called “Building Blocks” methods, that have been approved in Australia and the UK. In their report filed at Exhibit A2, Tab 10, Schedule 1, London Economics International LLC (“LEI”), explains how these models have been implemented in those other jurisdictions, and the similarities to EGD’s Customized IR plan, including the assessment and application of productivity.

8. EGD believes the combination of embedding and demonstrating that productivity has been incorporated in its budgeted cost forecasts, and then reporting, sharing and incentivizing further cost efficiencies during the IR term, are key parameters of the Customized IR plan that clearly establish it as a robust IR model.

<u>The Budget Forecasting Process</u>

9. This evidence describes how the 2014 to 2016 O&M budget was developed, and specifically how productivity has been assessed and implemented into the O&M forecast projections. A more detailed discussion of the O&M forecasts can be found at Exhibit D1, Tab 3, Schedule 1.

10. The O&M budget was developed by first conducting a grass-roots budget. That process yielded an O&M budget with forecast increases considerably higher than inflation. A target was then set to keep the growth rate of most of its O&M costs at or near expected inflation levels. Other segments of the O&M budget that

serve to make up the total are determined in accordance with past regulatory agreements or decisions, and relate to RCAM, Customer Care / CIS, DSM, and Pension/OPEB costs.

11. In summary, as set out within the D1 series of exhibits (O&M Overview and Departmental evidence), productivity that is implicitly accounted for in the O&M Budget forecasts for 2014 to 2016 includes the following:

(i) Striving to keep controllable O&M to an escalation rate that is less than inflation;
(ii) Not accounting for known and expected higher cost areas (benefits, contractor prices, number of locates);
(iii) Holding key cost components flat (quantity of labour, or FTEs, bad debts, and number of locates);
(iv) Holding other competitively determined prices to a rate at or below inflation (salary increases); and
(v) Not increasing O&M forecasts for incremental customer additions.

12. Since the O&M Budget forecast was by and large created by reference to the expected inflation rate, the Company foresees that there will be a significant challenge to managing at this level over the forecast horizon. Setting aside the potential for uncertainty with regard to the quantity and price of work required, there are numerous known challenges that will need to be overcome.

13. For example, it is expected that higher than inflation wage and benefit increases will be required to remain competitive in the labour market. Benefits are expected to increase 6.1% annually in 2014 and onwards. Salary increases are also expected to grow faster than the rate of inflation. As well, it is anticipated

that external contractors will increase their rates by more than inflation, between 3% and 6%. The combined impact of the 2014 to 2016 O&M Budget limiting budgeted increases in wages, benefits, and contractors to around 2% exposes the Company to a substantial risk of cost overruns. Cost increases in these very significant areas will need to be accommodated by productivity savings in other areas.

14. With respect to labour, the O&M and Capital forecasts assume the addition of no new FTEs. This will require an increase in productivity, as it requires the achievement of outputs with the same inputs. New approaches and activities will have to be developed to achieve this productivity. If incremental hiring is required, any associated costs will have to be accommodated elsewhere in the O&M Budget.

15. The passage and implementation of Bill 8 (the Underground Infrastructure Notification System Act) is also expected to drive higher requests for locates, and the costs for locates escalated by inflation may not be adequate to cover the increasing demand. The Company faces the risk of greater than anticipated requirements for safety, integrity and compliance with new legislation and regulations.

16. The Company has also not reflected any increase in bad debt costs in the O&M forecast, even though there is a high probability that bad debt expenses will in fact increase with a growing customer base and rising natural gas prices.

17. The departmental O&M evidence filed within the D1 series of exhibits describes additional required or expected productivity savings over the 2014 to 2016 term.

Witnesses: A. Mandyam
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18. In summary, the Company has implicitly recognized productivity into its forecast of O&M budgets for 2014 to 2016 by not accounting for known or highly probable cost increases over the forecast horizon, and by holding several costs flat, which in reality will not be flat, and by expecting the organization to deliver more output for the same inputs. These actions necessarily mean that EGD is taking on significantly more forecast risk than would be the case in a cost of service application, and they represent hurdles to overcome simply to achieve the Allowed ROE. In other words, to make up for the differential between actual costs incurred, and those built into the forecast, the Company will have no choice but to find offsetting cost efficiencies elsewhere.

19. With regard to Capital spending requirements, it is the combination of high capital spending requirements and uncertainty in the long term that have driven Enbridge to request approval of its Customized IR plan.

20. Enbridge has been able to include anticipated productivity and efficiency savings within its 2014 to 2016 Capital Budget, including the following:
    (i) Managing direct costs of adding new customers
    (ii) Keeping FTE levels flat
    (iii) Not accounting for considerable uncertainties within projects (variable costs)

21. As described, the Company has resolved to maintain its overall FTE level flat through the 2014 to 2016 period. To the extent that additional FTEs are needed to accomplish work, Enbridge will accommodate these costs within other parts of the 2014 to 2016 Capital Budget.

22. Exhibit B2, Tab 1, Schedule 1 also describes that many of the project forecast costs within the 2014 to 2016 Capital Budget contain significant uncertainty, and as a result, actual project costs may vary significantly. These costs are termed "variable costs". The "variable" costs are at Enbridge's risk and are not included in the 2014 to 2016 Capital Budget amounts. The significance here is that the amount of potential variable costs is greater than the actual cost forecast. While the Company does not expect all of these "variable" costs to materialize, there is a strong possibility that at least some of the costs will arise during the 2014 to 2016 term. As these costs are not included within the Capital Budget, they will have to be accommodated elsewhere. Under Enbridge's updated Customized IR plan, which will use the 2016 Capital Budget as the basis for forecast 2017 and 2018 Capital Budgets, the risks to Enbridge from not including these variable costs is increased. The result will be a requirement to find further productivity and efficiency gains, to allow for all necessary work to be completed, effectively forcing productivity to balance inflationary and growth pressures.

<u>Tests of Reasonableness</u>

23. Above, EGD has described how the budgeting process inputs and outputs have resulted in both implicit and explicit productivity in the establishment of the forecast Allowed Revenue amounts. In addition, EGD has looked to external and comparative views to demonstrate that productivity resides in these forecasts. Specifically, EGD engaged Concentric to prepare analyses concerning the Company's historical Total Factor Productivity ("TFP") and PFP. These analyses report on productivity trends for EGD and the industry which could be reasonably used to test whether EGD's cost projections meet industry productivity standards. Concentric's productivity studies can be found at Exhibit A2, Tab 9, Schedule 1.

Witnesses: A. Mandyam
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24. Concentric's TFP study results indicate that EGD's historical productivity performance was similar to that of the industry, as shown in the summary table:

	2000-2011	**2007-2011**
25 Company industry group	-0.32%	-1.22%
EGD	***-0.28%***	***-0.66%***
7 Company industry subgroup	-0.01%	-0.78%

25. The TFP analysis brings perspective to the fact that Enbridge's going-in rates from 2013 are efficient from an industry productivity perspective.

26. Concentric also assessed EGD's PFP performance relative to the industry, measuring O&M inputs to total outputs. Concentric finds that EGD's performance has been slightly better than the industry, and improved throughout the most recent IR period, while the rest of the industry faltered. The table below summarizes Concentric's PFP findings:

	2000-2011	**2007-2011**
25 Company industry group	-0.25%	-1.52%
EGD	***0.50%***	***0.60%***
7 Company industry subgroup	-0.02%	-1.33%

27. Overall, the analyses provided by Concentric show that EGD has maintained total productivity performance relatively equal to that of the industry over the long term, and has exceeded the industry in the recent past. O&M productivity has been even better, outpacing the industry over both the long term and the recent past by fairly significant margins.

Witnesses: A. Mandyam
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28. This demonstrates that EGD's productivity performance has been at or in excess of industry levels. To provide the Board with evidence that Enbridge's cost forecasts also contain continued productivity improvements, Concentric extended their analysis to compare the outcome that could reasonably be expected in an I-X approach.

29. Excluding the capital portion of the Allowed Revenue amounts, and focusing on O&M, an assessment can be made of the embedded productivity within Enbridge's 2014 to 2016 "Other O&M" budget (that is, all costs except Customer Care, DSM, and pension/OPEBs). Based on the PFP analysis, Concentric would recommend a PFP X-Factor of 0.0%. The relevant Inflation Factor that Concentric recommends results in a 2014 to 2016 annual estimate of 2.24%.

30. Concentric used these parameter values to test the reasonableness of the "Other O&M" component of EGD's revenue requirement forecasts. By extending the base year O&M by the I factor forecast less the X factor forecast, Concentric shows that EGD's O&M component of 2014 to 2016 Allowed Revenue contains approximately $12 Million of accumulated productivity over the course of those years which is above and beyond the industry productivity trend. That is, EGD is already considered to be a top industry performer, and the cost forecasts meet and exceed the expected industry productivity performance.

31. Concentric concludes(at page 49):

> *Concentric's analyses indicate that EGD's forecasted O&M costs are reasonable based on a comparison to the benchmark utilities, and in relation to productivity from the seven company sub-group PFP analysis. The $12 million in cumulative savings between the PFP I-X derived O&M costs and the EGD forecasted O&M cost can be viewed as additional productivity flowing through to customers, beyond the productivity that would be built into a PFP I-X formula.*

Witnesses: A. Mandyam
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Benchmarking

32. Benchmarking evidence provided by Concentric also shows the appropriateness of EGD's forecasted costs. In their report, Concentric demonstrates that EGD has historically been among the most efficient utilities, and the data further shows that EGD has maintained or improved its cost performance relative to industry peers. This is also consistent with the productivity analyses discussed above.

33. Concentric's analysis shows that EGD's 2011 O&M Expense per Customer are the fifth lowest among a 28 company peer group. They show that EGD's O&M per Customer has consistently been lower than the industry's and that the trend of increase has been considerably lower over a long time horizon.

34. The analysis also shows EGD's labour costs (excluding and including capitalized amounts) per customer are among the industry best. The benchmarking analysis shows total labour costs per employee, excluding capitalized amounts, are below the industry average with a recent trend that is noticeably lower than the industry trend. Including capitalized amounts, the total labour costs per employee for EGD are lower than, but much closer to industry norms.

35. The benchmarking analysis also considers another measure of efficiency, which is Total Customers per Employee. The data shows that EGD was in the highest quartile for this measure in 2011, and that EGD has always maintained many more customers per employee than the industry average.

36. One area where EGD's performance has been closer to the industry's performance is with respect to Net Plant per Customer. The data shows that EGD's 2011 Net

Plant per Customer is higher than the industry average, however, that the trend growth for EGD has been slower than the industry average.

37. In addition to the historical analysis, at Figure 26 of their report, Concentric also compared EGD's forecast costs to the 2011 peer group. The analyses show that EGD's forecasted O&M cost per Customer in 2014 is better than the industry average for 2011.

38. Regarding their overall benchmarking analysis, Concentric concludes (at page A-19):

> *On balance, the benchmarking analysis indicates that Enbridge is among the most efficient of its U.S. peers in most categories measured. The exceptions are net plant per customer, net plant per unit of volume, and labour costs (including capitalized labour) per employee, where the Company is closer to or above the average. Examining trends over the 2000 – 2011 period measured, Enbridge has generally sustained or improved its position in relation to its peers, including during the most recent IR plan period.*

39. Further, the data also show that on a per customer basis EGD's forecast O&M per Customer is considerably lower than an I-X derived O&M cost per Customer.

<u>Incentives to Find Further Efficiencies during the IR Plan Term</u>

40. As set out throughout this Application, there are various other features of EGD's proposed Customized IR plan that will serve to induce the right behaviours, and incent EGD's efforts towards even greater cost efficiencies beyond the efforts to reduce the 2014 to 2016 budget forecasts. The key features that will continue to incent efforts toward greater efficiencies during the plan include the Customized IR

plan design, the SEIM, the proposed ESM, the plan term, and the tracking and reporting of Performance Measurement metrics.

41. The Customized IR plan design necessarily creates incentives to induce cost controls and increase efficiency. That is, the Board's approval of the Allowed Revenues for each of the years of the IR plan effectively creates a revenue cap that is decoupled from actual costs over the term of the plan. EGD is taking the risk that it will be able to manage its business, including the necessary capital requirements, within the revenue cap.

42. Just as with an I-X price or revenue setting regime, EGD's model is designed such that future actual costs have no regard to the pre-determined revenue cap. Also, just as with an I-X price or revenue setting regime, there are no adjustments for cost elements throughout the plan term. Additionally, EGD is proposing to make annual adjustments to volume forecasts to better reflect current demand projections and supply planning, and to annually update a small number of items whose costs are subject to variance account treatment. As such, the Company is at risk for most costs over the projected revenue cap, and is incentivized to manage costs within the cap. As LEI comments in their report at Exhibit A2, Tab 10, Schedule 1(at page 5):

> *… Enbridge will have an opportunity to earn a fair return on its investments and appropriately recover capex, but only if it indeed can deliver on the productivity and operating cost budgets it has forecast alongside the capital investment requirements.*

43. Another element that will ensure that EGD engages in the right behaviors to pursue cost efficiencies is in the Company's proposed SEIM. The SEIM is intended to remove any disincentive for the utility to continue to invest in productivity

enhancements, by allowing the utility to generate ROE enhancements beyond the term of the IR plan. In this way, the SEIM will increase incentives for the Company to generate sustainable efficiencies, which will benefit ratepayers through lower rates beyond the term of the IR plan. Further details regarding the SEIM can be found at Exhibit A2, Schedule 11, Tab 3.

44. The design of the ESM also provides an incentive to improve cost performance. The ESM allows EGD to maintain the first 100 basis points of any potential over-earnings, and then 50% for any over-earnings beyond that, which is a powerful incentive to improve cost efficiency. The ESM will also provide a measure of protection to ratepayers that EGD has not over-forecast its costs.

45. The proposed ESM is also asymmetrical so that sharing only occurs if EGD over-earns, and not if the Company under earns. This means that the balance of risk resides with the utility, and with the increased risk, so too is there an increased incentive to efficiently manage costs. As LEI says within their report (at page 19),

> *Enbridge's proposal to continue its conservative, customer-favoring ESM is consistent with all the principles discussed above and will provide a strong incentive to implement efficiency measures, as Enbridge will receive initial benefits, while customers will also share in the gains above the threshold. Furthermore, the ESM under a building blocks approach discourages cutbacks in investment to boost profitability as these ultimately will be returned to customers*

46. A multi-year plan term provides incentives in that there is no recourse to request rate relief over the plan term absent the 300 basis point shortfall against the Allowed ROE (i.e. the Off-ramp). Essentially, to earn the Allowed ROE, EGD must manage its costs effectively. At the same time, EGD still has to serve on its commitment to the delivery of safe and reliable energy, which will require significant

investment. Cutting costs by simply not undertaking projects built into the forecasts will negatively impact meeting that commitment.

47. Finally, by committing to the tracking and reporting of productivity and performance metrics the Company will make visible, and be held to account, on progress in meeting safety and integrity commitments, customer service quality, and productivity. The proposed performance measurement framework will provide the OEB and stakeholders a reporting mechanism that demonstrates the Company's activities in pursuing productivity. The objectives of the proposed Productivity Initiatives Report are as follows:
   (i) Establishment and maintenance of records of productivity and efficiency initiatives;
   (ii) Simplicity; and
   (iii) Visibility to linkages between initiatives and outcomes, i.e. the reports will focus on illustrating initiative's results[1] whether the results are successful or not.

48. In determining the productivity and efficiency initiatives that will be pursued over the incentive regulation term, the Company has established the following guiding principles:
   (i) Efficient and effective use of resources;
   (ii) Doing things right (efficient) and doing the right things (effective);
   (iii) Sustainable savings over multiple periods; and
   (iv) Optimal balance between effort and outcomes that are valued by stakeholders, e.g. safe and reliable energy supply at a reasonable cost.

[1] Measurable actual or avoided cost savings, i.e. savings that can be tracked quantitatively.

49. As well, EGD is committed to producing a Performance Metrics Benchmarking Report. The objective of this report is to compare actual results of the Performance Metrics with either the industry average or best practices from other gas utilities. The benchmarking will compare the metrics relative to comparable peer companies in terms of direction and trending. Results from the benchmarking comparison may be used as inputs to further inform improvements or adopt specific best practices from gas utilities that have similar operations to EGD's, as appropriate. The specific areas for measurement and reporting will include metrics and information regarding Customer Relationship, Operational Performance, and Financial Performance.

50. More details on the proposed Performance Measurement Framework can be found at Exhibit A2, Tab 11, Schedule 12.

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CHALLENGES OF AN I-X IR MODEL

Purpose of this Evidence

1. The purpose of this exhibit is to describe the challenges of an Inflation minus Productivity Factor ("I-X") formula based incentive regulation model for Enbridge Gas Distribution ("EGD" or "Company") in a 2nd Generation IR ("IR") term. This is accomplished through the development of a number of scenarios that determine ROE deficiency/sufficiencies assuming a revenue cap per customer I-X model versus forecast allowed ROE using the Company's filed budget O&M and capital forecasts. The development of "I" and "X" Factors is discussed in evidence provided by Concentric Energy Advisors, Inc. ("Concentric") at Exhibit A2, Tab 9, Schedule 1.

2. Specifically, this evidence will present:
   a) EGD System Challenges
   b) Traditional Model for Cost Recovery
   c) Limitations of I-X Frameworks
   d) Challenge of an I-X model in EGD's circumstances
   e) Challenge of Increasing Depreciation and Amortization Expense
   f) Other Considerations for a Customized IR

EGD System Challenges

3. EGD is one of North America's oldest investor owned, regulated natural gas distribution utilities and it shares many of the common challenges facing utilities across the globe – an increased focus on safety and reliability, aging assets and the need to cost effectively meet the demands of customer growth in its franchise area. In addition to these common challenges, Enbridge has one of the fastest growing customer bases in North America, which brings other cost challenges.

Witnesses: S. Kancharla
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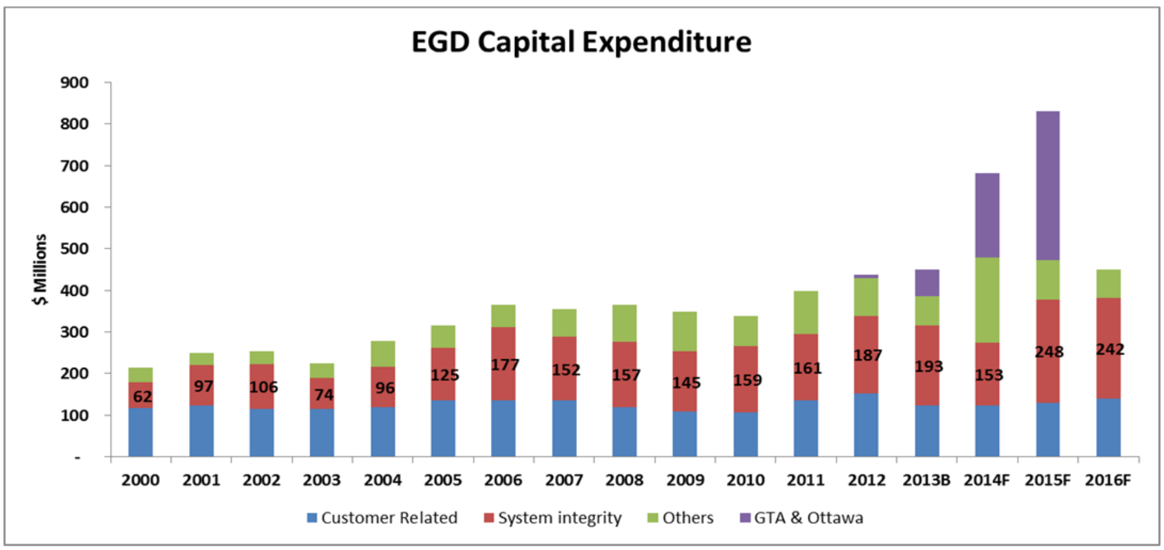
Notwithstanding these characteristics, EGD remains committed to the safe, reliable operation of its gas distribution network and has made that commitment a business priority.

4. Over the last decade, EGD has experienced an increased need for system improvement and integrity related capital. As shown in the illustration below, the share of system integrity capital has been increasing historically and is expected to increase more significantly in the future.



5. EGD's Customized IR plan is structured to respond to these forecast business needs, which includes the expectation for significant increased capital investments for safety, system integrity and reliability initiatives driving the next 3 to 5 years. Specifically, EGD needs to increase its capital spending over the next 3 years to address unavoidable issues such as safety and integrity issues, relocations, IT projects, and the GTA and Ottawa Reinforcement projects. In fact, EGD's total capital expenditures over the next three years are forecast to be approximately

$2.0 billion, which represents a 53% increase over the total capital spent during the previous three years.

6. This significant increase in capital spending translates directly into higher rate base and higher annual depreciation expense, which in turn results in an annual Allowed Revenue amount that is much higher than what a traditional Total Factor Productivity ("TFP") based "inflation less productivity" IR methodology would provide.

7. The needs of the utility pose a challenge to EGD to develop an IR framework that accommodates the financial consequences associated with growing incremental capital. A traditional formula I-X based framework, with the X factor defined by reference to industry average TFP trends, was found to be insufficient to meet those needs because it clearly does not anticipate the unusual capital spending demands facing EGD. The traditional I-X approach will not provide EGD the capacity to fund its project capital investment needs and afford EGD a reasonable opportunity to earn the allowed return. As a result, the proposed Customized IR plan was developed.

8. EGD's 1st Generation IR model relied on an I-X escalator supplemented with a revenue cap per customer calculator and Y factors for specific incremental projects not subject to the revenue escalator. These "add-ons" to the traditional I-X model were designed to recognize the unique needs of the business during the term of the 1st Generation IR relating to funding customer growth and specific incremental projects not included in the 2007 base revenue requirement. These "add-ons" necessarily increased the complexity of the IR model. As the need for capital increases, additional "add-ons" in the form of new Y factors or other mechanisms

such as capital trackers, would be required to increase the possibility that an I-X framework could work for EGD in the coming years. The inherent complexity of the 1st Generation IR framework would, as a result increase, further straining the applicability of a formula-based model for EGD's 2nd Generation IR term.

9. The scenarios evaluated below analyze whether an I-X model is still appropriate for EGD for its 2nd Generation IR term and also examine whether the creation of additional Y factors for EGD's two major reinforcement projects impoves the prospects for EGD to earn its allowed return. The analysis also determines the results of a scenario where I-X is assumed to be held to the average I-X level that applied during the term of EGD 1st Generation IR and further assumes Y factors for the two major reinforcement projects.

Traditional Model for Cost Recovery

10. In a traditional Cost of Service ("COS") framework, all else being equal, rates are designed to result in neither a revenue sufficiency or deficiency, ensuring that all cost elements that contribute to the determination of revenue requirement are recovered. In turn, a COS framework generally provides a utility the ability to earn its allowed return. The utility's costs are reviewed closely before the regulator approves them for recovery through rates to ensure they are both prudent and just and reasonable expenditures.

11. Non-revenue generating capital investments, for example, replacements and certain reinforcements and relocations which ensure system reliability, cause upward pressure on rates as they do not promote customer attachment or result in increases in volume delivery. Traditional ratemaking frameworks such as COS allow for the recovery of prudent costs in rates, whereas in an I-X model, the

percentage escalator must be sufficiently high to generate revenue increases to cover the costs of non-revenue generating capital investment without undermining a utility's reasonable opportunity to earn the allowed return.

Limitations of I-X Frameworks

12. Many utilities (and regulators) around the world have adopted multi-year Performance Based Ratemaking ("PBR") frameworks to overcome some of the perceived weaknesses of COS regulation by incorporating incentive mechanisms and productivity in models that in turn encourage innovation and the realization of sustainable efficiencies. IR models are traditionally formula-based, starting from a COS rebasing year with revenue or rates escalated during the IR term through consideration of inflation and productivity factors in an I-X escalation formula. Multi-year IR plans encourage efficiencies and provide incentives for utilities to realize those efficiencies.

13. Under that form of IR, the utility is expected to manage its business within the confines of the I-X formula design. In this model, incremental capital expenditures produce an earnings drag since the utility is prevented under most circumstances from filing a COS rate case. This situation may be untenable in an environment where the growth rate in depreciation costs and other cost elements driven by capital investments more than outstrip the growth in revenue from the I-X formula. Further, finding efficiencies may be increasingly difficult, especially for a utility like EGD that can demonstrate a long history of strong relative productivity performance. In this case, the utility is forced to forego the return on and the return of the capital that is invested until there is a rebasing, which significantly impacts a utility's ability to earn a Fair Return, as defined by the Fair Return Standard.

14. For example, assume there is a $100 million increase in net capital above historic levels, driven by reinforcement and replacement projects. The incremental revenue required to provide cost recovery in a traditional COS model is approximately $8 million. This level of change from historical capital spending creates a condition where the normal rate of industry productivity improvement using I-X cannot reasonably compensate for the incremental costs. In addition, in subsequent years, there will be additive pressures to find more productivity enhancements as the foregone return on capital continues to accumulate. This situation creates a built-in disincentive to invest in non-revenue generating projects. It is noteworthy that safety and integrity projects are, by their very nature, non-revenue generating projects.

Challenge of an I-X model in EGD's circumstances

15. In a traditional I-X IR framework, base rates are established in a rebasing year from an approved revenue requirement. At a high level, the approved revenue requirement includes operating cost and capital cost elements, including depreciation, return on capital and income tax. During an IR term, changes in revenue recovered through rates are capped by the application of an I-X adjustment factor (for a revenue cap).

16. In order to determine whether and how the Company could continue for a 2nd Generation IR term using a plan similar to the 1st Generation IR plan, Enbridge completed various financial analyses. The results of the analyses, which considered a variety of scenarios using an I-X framework, including additional Y factors for EGD's two major reinforcement projects, indicated that an alternative IR approach is required from that adopted for the 1st Generation IR term.

17. The analysis compared the expected ROE derived from an I-X framework versus the forecast allowed ROE using the Board's ROE formula to determine whether Enbridge could reasonably recover its capital investment and earn the Fair Return over the IR term.

Description of the analysis:

18. For each scenario, a revenue cap per customer calculator with an I-X revenue escalator was assumed and customer growth was forecast. The following factors were considered as Y factors (flow through costs) for each scenario - Carrying cost for Gas in storage; Pension Cost; DSM; and Customer Care. Forecast achieved ROEs were then compared to forecast allowed ROEs.

19. The following six scenarios were evaluated :

    a) Scenario 1: No new Y factors for I-X model.
    b) Scenario 2: Scenario 1 plus new Y factors for the GTA and Ottawa reinforcement projects.
    c) Scenario 3: Breakeven escalation factor such that annual average ROEs in Scenario 2 are equal to forecast allowed ROE.
    d) Scenario 4: Scenario 2 plus reduction in depreciation expense and accumulated depreciation from reduction in Site Restoration Costs.
    e) Scenario 5: Breakeven escalation factor such that annual average ROEs in Scenario 4 are equal to forecast allowed ROE.
    f) Scenario 6: Same assumptions as Scenario 4 except I-X is assumed equal to the actual effective average I-X during the 1st Generation IR term.

Key assumptions for the analysis:

20. For Scenarios 1 to 5, EGD assumed that the I-X escalator would equal 2.5%, based on an I factor forecast of 2.5% and a productivity factor or X factor of 0%. The I factor forecast represents the average composite inflation rate that applies to EGD's costs as recommended and forecast by Concentric at Exhibit A2, Tab 9, Schedule 1. The X factor is the recommended productivity factor derived from Concentric's TFP analysis in their report. For Scenario 6, EGD assumed an I-X = 0.9%.

21. These scenarios were evaluated for each of the next three years, assuming levels of capital and O&M spending that are consistent with Enbridge's forecast budgets included in this IR application (and which include embedded productivity).

22. The table below provides details of the other assumptions used in the analysis.

Assumptions

$ Millions	**2014**	**2015**	**2016**
Capital expenditure	682	832	450
Operating expenses	425	429	440
Customer growth	1.69%	1.73%	1.75%
Weighted Average Cost of debt (LT&ST)	5.41%	5.36%	5.31%
Allowed ROE	9.27%	9.72%	10.12%
Tax rate	26.50%	26.50%	26.50%
Inflation factor	2.45%	2.45%	2.45%
Productivity factor *	0.00%	0.00%	0.00%
Composite depreciation rate before SRC adjustment	4.03%	3.99%	3.94%
Composite depreciation rate with SRC adjustment	3.59%	3.55%	3.50%
Constant Dollar Net Salvage Value Adjustment	68.1	63.1	58.1

* Productivity savings are embedded within Enbridge's budgets

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and Interpretation of Scenario 1

23. Scenario 1 assumes no new Y factors for the GTA and Ottawa reinforcement projects. The 3 year average escalation factor is 2.5% and with customer growth, IR revenue is growing 4.2% per year. Layering on the existing Y factors results in average annual IR revenue growth of 3.5%. In this scenario, the achieved average annual ROE over the IR term would be 1.8% less than forecast allowed ROE.

Sc1: No new Y factors for I-X Model

Revenue - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	*2.5%*
Productivity		0.0%	0.0%	0.0%	
		2.5%	2.5%	2.5%	*2.5%*
Customer growth		1.7%	1.7%	1.7%	*1.7%*
		4.2%	4.2%	4.2%	*4.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**-**			
2013 Adjusted Revenue Requirement - Subject to escalation		**817**			
Revenue Requirement - IR with escalation	817	**851**	**887**	**925**	***4.2%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	-	-	-	
Site Restoration Cost - Tax impact	-	-	-	-	
	204	203	206	209	
Total Distribution Revenues -IR	**1,021**	**1,055**	**1,093**	**1,133**	***3.5%***
Achieved ROE	**8.9%**	**8.3%**	**8.7%**	**6.6%**	***7.9%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Acheived vs Allowed)	**0.0%**	**-1.0%**	**-1.0%**	**-3.5%**	**-1.8%**

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and Interpretation of Scenario 2

Sc2: Scenario 1 plus new Y factors for the GTA and Ottawa reinforcement projects

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	*2.5%*
Productivity		0.0%	0.0%	0.0%	
		2.5%	2.5%	2.5%	*2.5%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		4.2%	4.2%	4.2%	*4.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**-**			
2013 Adjusted Revenue Requirement - Subject to escalation		**817**			
Revenue Requirement - IR with escalation	817	**851**	**887**	**925**	***4.2%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	64	
Site Restoration Cost - Tax impact	-	-	-	-	
	204	209	218	273	
Total Distribution Revenues -IR	**1,021**	**1,060**	**1,105**	**1,198**	***5.5%***
Achieved ROE	**8.9%**	**8.6%**	**9.2%**	**9.1%**	***9.0%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Acheived vs Allowed)	**-**	**-0.7%**	**-0.5%**	**-1.0%**	**-0.7%**

24. In this scenario, the major reinforcement projects in the GTA and Ottawa were considered as new Y factors in the I-X model. Layering on the existing Y factors and new Y factors for the two major reinforcement projects results in IR revenue growth of 5.5%. In this scenario, the achieved average annual ROE over the IR term under an I-X model would be 0.7% less than forecast allowed ROE.

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and interpretation of Scenario 3

Sc3: Breakeven escalation factor such that ROEs in Scenario 2 from I-X and allowed ROE are equal

	Rebase	Second Generation IR			
Revenue Requirement - IR ($M)	**2013**	**2014**	**2015**	**2016**	***3 yr - CAGR***
Escalation factor					
Escalation factor (Inflation)		4.3%	2.0%	4.0%	*3.4%*
Productivity		0.0%	0.0%	0.0%	
		4.3%	2.0%	4.0%	*3.4%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		6.0%	3.7%	5.9%	*5.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**-**			
2013 Adjusted Revenue Requirement - Subject to escalation		**817**			
Revenue Requirement - IR with escalation	817	**866**	**898**	**951**	***5.2%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	64	
Site Restoration Cost - Tax impact	-	-	-	-	
	204	209	218	273	
Total Distribution Revenues -IR	**1,021**	**1,075**	**1,116**	**1,224**	***6.2%***
Achieved ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Acheived vs Allowed)	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

25. In this scenario, the GTA and Ottawa reinforcement major projects were considered as new Y factors in the I-X model and an escalation factor is solved to produce ROEs from the I-X model equal to forecast allowed ROE. The 3 year I-X average escalation factor required in this case is 3.4%. This escalation factor is significantly

greater than the 2.5% I-X derived from the productivity factor and inflation factors that are recommended and forecast by Concentric for an I-X IR model framework.

26. For the next two scenarios, the recommendations of the new depreciation study are incorporated. The key differences arise from the changes in “Site Restoration Costs” collected as part of depreciation expense and from the changes in “site restoration costs” accumulated and shown in “accumulated depreciation”. For details, please refer to Exhibit D1, Tab 5, Schedule 1.

Analysis and interpretation of Scenario 4

Sc4: Scenario 2 plus reduction in depreciation expense and accumulated depreciation from reduction in Site Restoration costs

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	*2.5%*
Productivity		0.0%	0.0%	0.0%	
		2.5%	2.5%	2.5%	*2.5%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		4.2%	4.2%	4.2%	*4.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**(39)**			
2013 Adjusted Revenue Requirement - Subject to escalation		**778**			
Revenue Requirement - IR with escalation	817	**811**	**845**	**881**	***2.5%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
Site Restoration Cost - Tax impact	-	(18)	(17)	(15)	
	204	191	201	256	
Total Distribution Revenues -IR	**1,021**	**1,001**	**1,046**	**1,137**	***3.6%***
Achieved ROE	**8.9%**	**8.8%**	**9.2%**	**8.8%**	***8.9%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (IR vs COS)	**0.0%**	**-0.5%**	**-0.5%**	**-1.3%**	**-0.8%**

27. In this scenario, the major reinforcement projects in the GTA and Ottawa were considered as new Y factors in the I-X model. Layering on the existing and new Y factors, and impacts of the new Depreciation Study results, IR revenue growth of 3.6% was calculated. The forecast average annual ROE over the IR term under an I-X model is 0.8% less than allowed ROE.

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and Interpretation of Scenario 5

Sc5: Breakeven escalation factor such that ROEs in Scenario 4 from I-X and allowed ROE are equal

	Rebase	Second Generation IR			
Revenue Requirement - IR ($M)	**2013**	**2014**	**2015**	**2016**	***3 yr - CAGR***
Escalation factor					
Escalation factor (Inflation)		3.8%	2.7%	4.9%	*3.8%*
Productivity		0.0%	0.0%	0.0%	
		3.8%	2.7%	4.9%	*3.8%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		5.5%	4.5%	6.7%	*5.6%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**(39)**			
2013 Adjusted Revenue Requirement - Subject to escalation		**778**			
Revenue Requirement - IR with escalation	817	**821**	**858**	**916**	***3.9%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
Site Restoration Cost - Tax impact	-	(18)	(17)	(15)	
	204	191	201	256	
Total Distribution Revenues -IR	**1,021**	**1,012**	**1,059**	**1,172**	***4.7%***
Achieved ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (IR vs COS)	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

28. In this scenario, the major reinforcement projects were considered as new Y factors and the impacts of the new depreciation study are incorporated. The required I-X escalation factor is solved to produce ROEs from the I-X model equal to forecast allowed ROE. The 3 year average escalation factor required in this case is 3.8%. This required escalation factor is significantly greater than the forecast inflation and productivity factor of 2.5% recommended and forecast by Concentric.

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and Interpretation of Scenario 6

Sc6: Same asumptions as Scenario 4 except I-X is assumed equal to the actual effective I-X during 1st Generation IR term

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		1.7%	1.7%	1.7%	*1.7%*
Productivity		50.0%	50.0%	50.0%	
		0.9%	0.9%	0.9%	*0.9%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		2.6%	2.6%	2.6%	*2.6%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**(39)**			
2013 Adjusted Revenue Requirement - Subject to escalation		**778**			
Revenue Requirement - IR with escalation	817	**798**	**819**	**841**	***1.0%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
Site Restoration Cost - Tax impact	-	(18)	(17)	(15)	
	204	191	201	256	
Total Distribution Revenues -IR	**1,021**	**989**	**1,020**	**1,096**	***2.4%***
Achieved ROE	**8.9%**	**8.2%**	**8.1%**	**7.3%**	***7.9%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (IR vs COS)	**0.0%**	**-1.1%**	**-1.6%**	**-2.8%**	**-1.8%**

29. In this scenario, the major reinforcement projects in the GTA and Ottawa were considered as new Y factors in the I-X model, with I-X assumed to be equal to the actual effective I-X during the 1st Generation IR term. The 3 year average escalation factor is 1.7% and with customer growth, the IR escalation is 2.6%.

Witnesses: S. Kancharla
R. Fischer
M. Lister

Layering on the existing and new Y factors, and impacts of the new depreciation study results, IR revenue growth of 2.4% was calculated. The forecast average annual ROE over the IR term under the I-X model is 1.8% less than forecast allowed ROE.

Summary of Financial Scenario Analysis

30. The following table provides the summary of all the scenarios analysed above.

Summary of Scenarios

	Annual Average Allowed ROE Deficiency 2014-2016
S1: No New Y factors	-1.8%
S2: GTA and Ottawa as new Y factors	-0.7%
S4: New Y factors and impacts of changes to site restoration costs	-0.8%
S6: Same as S4 except I-X equal to the actual effective I-X during 1st Generation IR	-1.8%
	Average Breakeven Escalation factor to achieve the Allowed ROE
S3: Breakeven for S2	3.4%
S5: Breakeven for S4	3.8%

31. Significant deficiencies below forecast allowed ROEs were determined for each I-X scenario, even assuming Y factor treatment for the major GTA and Ottawa reinforcement projects. This indicates that under continued application of the 1st Generation IR plan, EGD would be highly unlikely to earn the fair return. From another perspective, to earn a fair return and have a reasonable opportunity for timely recovery of capital investment, the escalation factor in an I-X model would need to be significantly higher than traditional values for I and X factors. To

mitigate this under-earning, if the only lever was operating expenses, annual operating expenses would need to be reduced by approximately $51 million, which is clearly unattainable and not reasonable.

32. As demonstrated above, the primary reason why a model with features consistent with Enbridge's 1st Generation IR plan, fails to offer an appropriate opportunity to earn a Fair Return, is due to the increased capital needs of the business. In large part, this is caused by increases in depreciation expense, which is addressed in the next section of this evidence.

The Challenge of Increasing Depreciation and Amortization Expense in an I-X Framework

33. Depreciation and amortization expense is a major revenue requirement component in a traditional cost of service build up of cost elements. For EGD, in 2013, depreciation and amortization is forecast to equal $279 million, representing almost 30% of the total estimated revenue requirement. Even with the reduction in depreciation expense due to the proposed adjustment to depreciation rates, in 2014 (related to site restoration costs), depreciation and amortization expense is forecast to increase from an adjusted level of $240 million[1] in 2013 to $304 million in 2016, an increase of $64 million over 3 years. The majority of this increase is due to the capital additions forecast during those years.

34. In Scenario 4, which includes Y factors for the major reinforcement projects and the impact of changes to SRC, revenue from an I-X and revenue cap per customer escalator is forecast to grow from $778 million (adjusted for reduction in depreciation expense with SRC) in 2013 to $881 million in 2016, an increase of

[1] The "adjusted level" is determined by applying the impact of the depreciation rate change to the 2013 base.

$103 milllion. In other words, around 60% of the forecast revenue growth must be attributed to growth in depreciation and amortization, leaving an estimated $39 million to "pay for" increases in the remaining cost elements, including O&M, cost of capital and tax. Stated another way, though depreciation and amortization expense represents less than 30% of the estimated revenue requirement in 2013, 60% of the forecast revenue growth from the formula must cover forecast growth in depreciation and amortization over the IR term. That leaves an insufficient amount to cover increases in all other items.

35. Depreciation and amortization expense is growing at more than twice the rate of forecast revenue growth. The remaining incremental revenue is insufficient to cover the growing costs associated with O&M, cost of capital and tax, and therefore growing depreciation and amortization expense is a major contributor to the forecast revenue deficiencies and challenge of a formulaic IR model for EGD.

Conclusion

36. The analyses demonstrate that significant revenue and ROE deficiencies are likely to occur if EGD were to adopt an I-X model for the 2nd Generation IR Plan similar to that adopted in EGD's 1st Generation IR.

37. The analyses also show that, the escalation factor that is required to allow for capital recovery and the opportunity to earn a Fair Return is well in excess of traditional values for I and X. This condition has arisen as a result of significantly higher reinforcement requirements, and safety, integrity, and reliability drivers. EGD does not believe that the introduction of additional adders to the formula could accommodate the total required increase in capital spending, as the inevitable result would include many more Y factors and capital trackers, adding further

complexity to the IR model framework. This would cause the IR framework to become too unwieldy and invite criticism of a model that includes too much patchwork and complexity.

38. Instead, the Company is proposing a Customized IR plan for its 2nd generation IR model which includes productivity, appropriate incentives, a mechanism for ratepayers to share in additional savings beyond productivity build into the forecast, and other features to mitigate the probability of unintended consequences. The Customized IR plan, in addition to greatly simplifying the IR model construct, is appropriate to meet the needs of the utility.

Witnesses: S. Kancharla
R. Fischer
M. Lister

RATE ADJUSTMENT PROPOSAL – 2014 FISCAL YEAR

1. This evidence describes the proposed rate adjustment for the 2014 Fiscal Year.

2. Enbridge has calculated a total revenue sufficiency of $9.7 million for the 2014 Fiscal Year. This revenue sufficiency is the result of an Allowed Revenue amount that is less than revenues at existing rates.

3. The 2014 Allowed Revenue amount has been determined as set out at Exhibit A2, Tab 3, Schedule 1. The detailed buildup of the Allowed Revenue can be found at Exhibit F1, Tab 1, Schedule 1. The total Allowed Revenue amount has been determined to be $2,562.3 million.

4. The revenues at existing rates can be found at Exhibit F1, Tab 1, Schedule 1. This amount is produced as the sum of the forecast number of customers and volumes by rate class multiplied by existing rates by rate class. The 2014 volume forecast can be found at Exhibit C1, Tab 2, Schedule 1. The total revenue at existing rates has been determined to be $2,572.6 million.

5. With the net sufficiency of $9.7 million, EGD proposes to set 2014 Fiscal Year rates according to the cost allocation and rate design schedules produced in the “G” and “H” series of exhibits. For the typical residential customer, this results in an estimated rate decrease of 0.7%, or an estimated annual bill decrease of approximately $4 annually.

6. As described at Exhibit D1, Tab 5, Schedule 1, Enbridge also proposes to credit ratepayers with a portion of depreciation costs related to site restoration costs that have been collected in prior years. These amounts will be credited to

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

customers over five years. In 2014, this proposal will result in a bill reduction of approximately $26 for the average customer. Taken together with a bill reduction of approximately $4 due to a rate decrease (see paragraph 5), the average residential customer will experience a bill reduction of approximately $30 in 2014 (i.e., from approximately $867 in 2013 to $837 in 2014).

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

2014 TO 2018 RATE ADJUSTMENT PROCESS

1. This evidence describes Enbridge Gas Distribution's ("Enbridge" or the "Company") proposal to adjust rates for the years of the Customized IR plan term – 2014 to 2018.

2. The rate adjustment process under the Customized IR plan is very consistent with Enbridge's 1st Generation IR plan. Under the Customized IR plan, Allowed Revenue amounts will be set by the Board in this proceeding, and then subject to adjustment in annual Rate Adjustment proceedings from 2015 to 2018 to take account of updated impacts of volumes, gas costs and discrete pass-through cost items. Those same types of items were updated each year during the 1st Generation IR plan, though annual Rate Adjustment proceedings.

3. As explained in the updated Exhibit A2, Tab 1, Schedule 1, Enbridge has updated its Customized IR Plan to enable Allowed Revenue amounts to be set within this proceeding for all five years of the IR term (2014 to 2018). To accomplish this, Enbridge will set its 2017 and 2018 Capital Budgets based upon the 2016 Capital Budget. The rationale for why this is an appropriate approach is set out within the updated Exhibit B2, Tab 1, Schedule 1. This approach eliminates the requirement for Enbridge's 2017 and 2018 Capital Budgets to be presented and approved in a Phase I of the 2016 Rate Adjustment proceeding. Under this approach, Enbridge is at risk (except within three specified areas of spending) for any additional capital spending requirements in 2017 and 2018 other than those identified within the 2016 Capital Budget.

4. The evidence in this case presents Enbridge's cost forecasts required to build the annual Allowed Revenue amounts for the 2014 to 2016 years within Enbridge's

Customized IR plan. As explained below, these cost forecasts are also used, with appropriate adjustments, to build the Allowed Revenue amounts for 2017 and 2018.

5. Enbridge is requesting Board approval of Allowed Revenue amounts for each year from 2014 to 2018 within this Application.

6. As explained at Exhibit A2, Tab 2, Schedule 1, for the 2014 Fiscal Year Enbridge is also requesting approval of the 2014 volume forecast that underpins the revenue at existing rates and the resulting sufficiency / deficiency. Finally, Enbridge is seeking approval of the resulting rates for 2014.

7. Enbridge is not seeking approval of rates for 2015 to 2018 at this time. Rates for those years will be set through annual Rate Adjustment proceedings which will apply updated volume forecasts to the Allowed Revenue amounts approved in this proceeding. The 2015 to 2018 volume forecasts and the resulting revenues at existing rates presented in the case are intended to be proxies for the determination of revenues at existing rates, and the resulting revenue sufficiency/deficiency in those years.

8. In the following paragraphs, the Company sets out how:

    a. Allowed Revenue amounts for 2014 to 2018 will be determined within this proceeding.

    b. The annual Rate Adjustment process to set rates for each year from 2014 to 2018 will work, including:
        i. The process to set final rates for 2014; and

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

ii. The process to set final rates for 2015 to 2018, which will involve the updating of volumes and associated forecast revenues and gas costs, as well as updates within the final allowed Revenue Amounts for each year for customer care, DSM and pension/OPEB costs.

Process for Determining Allowed Revenue Amounts for 2014 to 2018

9. The Allowed Revenue amount for each year is determined by summing together the following elements: the cost of capital, operating costs, depreciation costs and taxes, less an offset amount for other revenues.

10. The Company has filed detailed evidence setting out how each of these elements, and the overall Allowed Revenue, can be determined for the years from 2014 to 2016. As explained in the updated Customized IR Plan evidence (Exhibit A2, Tab 1, Schedule 1), Enbridge cannot provide a reliable line-by-line forecast of capital spending requirements for 2017 and 2018 at this time However, in order to enable Allowed Revenue amounts for those years to be set in this proceeding, Enbridge's updated Customized IR Plan provides for the 2016 Capital Budget to be used to represent forecast 2017 and 2018 capital spending requirements.

11. As noted, Enbridge's updated Customized IR Plan provides for Allowed Revenue amounts for all five years of the IR term to be set in this proceeding. The components of Allowed Revenue are the same for all years. There are, however, differences between how these components are derived for 2014 to 2016 (based upon detailed budgets) as compared to 2017 and 2018 (where certain components are derived using adjustments to the 2014 to 2016 budgets). In the subsections below, explanation is provided about how the Allowed Revenue amounts will be set in this proceeding for 2014 to 2016, and for 2017 and 2018.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

12. The Allowed Revenue amounts for 2014 to 2018 that are being set within this proceeding are set out at the updated Exhibit F1, Tab 1, Schedule 1. These 2014 to 2018 Allowed Revenue amounts are referred to as "final" in this evidence, because they will not be adjusted except to take account of the items that will be updated within the annual Rate Adjustment proceedings. The final Allowed Revenue amounts for 2015 to 2018 are to be used as the starting point within the annual Rate Adjustment proceedings to set final rates for 2015 through 2018. Final rates for 2014 are being set within this proceeding.

(i) Determination of the final Allowed Revenue amounts for 2014 to 2016, to be set within this proceeding

13. The Allowed Revenue amounts for each year from 2014 to 2016 are set based on the following elements:

    a. Rate Base: The 2014 value is determined beginning with the use of the 2013 Board-approved closing rate base values (from EB-2011-0354) and applying the forecast 2014 Capital Budget and working capital inputs and applying impacts of the return of site restoration cost ("SRC") reserve amounts to determine the appropriate 2014 Rate Base level. The 2015 and 2016 Rate Base amounts are determined through the application of 2015 and 2016 Capital Budget and working capital inputs and site restoration cost ("SRC") return impacts. The relevant evidence is set out in the B series of exhibits.

    b. Rate of Return on Rate Base: The values for each year are set through the application of the forecast debt rates, and level of debt, and the forecast applicable ROE level, as set out within the E series of exhibits.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

c. Gas Costs: The values for each year are determined based upon the proxy volume forecasts as applied to the proxy gas supply plans for each year. This volume information is set out in in Exhibit C1, Tab 2, Schedule 1, and the gas costs forecasts are set out in Exhibits D3/D4/D5, Tab 3, Schedule 1. The Gas Costs inputs into Allowed Revenue will be updated within each annual Rate Adjustment proceeding.

d. Operating & Maintenance Costs: The values for each year are determined based upon the O&M Budget information set out in the D1 series of exhibits. The values related to customer care/CIS, pension/OPEB and DSM costs will be updated within each annual Rate Adjustment proceeding.

e. Depreciation Costs: The values for each year are determined based upon the forecast Capital Budget impacts, using the proposed updated depreciation rates. Evidence can be found within the B series of exhibits (Capital Budget) and at Exhibit D1, Tab 1, Schedule 1 and Exhibit D1, Tab 5, Schedule 1.

f. Fixed Financing Costs: The values for each year represent a forecast of the administration, extension and standby fees associated with the Company's committed credit facility. Evidence can be found at Exhibit E1, Tab 2, Schedule 1.

g. Municipal and Property Taxes: The values for each year are based on a forecast of taxes as applied to the Company's relevant assets. Evidence can be found within Exhibit D1, Tab 6, Schedule 1.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

h. Other Operating Revenue: The values for each year are based on forecasts of revenues for items such as Transactional Services, Open Bill Access, Late Payment Penalties, Other Service Charges and DPAC. Evidence can be found within the C series of exhibits.

i. Income Taxes: The values for each year are based on a forecast of income tax rates applied to forecast utility taxable income. Evidence can be found in Exhibits D3/D4/D5, Tab 1, Schedule 1.

(ii) Determination of the final Allowed Revenue amounts for 2017 and 2018, to be set within this proceeding

14. The final Allowed Revenue amounts for 2017 and 2018 that are being set within this proceeding are provided within Exhibits F6 and F7, and are set based on the following elements:

a. Rate Base: The 2017 Rate Base amount is determined beginning with the use of the 2016 closing rate base values and applying (as a reasonable forecast of 2017 requirements) the forecast 2016 Capital Budget[1] and working capital inputs and 2017 SRC return amount impacts to determine the appropriate 2017 Rate Base level. The 2018 Rate Base amount is determined through the application (as a reasonable estimate of 2018 requirements) of 2016 Capital Budget and working capital inputs and 2018 SRC return amount impacts.

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[1] Note, as explained within Exhibit B2, Tab 1. Schedule 1, that the 2016 Capital Budget used for 2017 and 2018 is reduced by $8.1 million to account for the fact that the WAMS project costs will not recur in those years.

b. Rate of Return on Rate Base: The values for each year are set through the application of the forecast debt rates, and level of debt, and the forecast applicable ROE level for 2017 and 2018, as set out within the E6 and E7 series of exhibits.

c. Gas Costs: The values for each year are determined based upon the proxy 2016 volume forecasts (used as a proxy for 2017 and 2018) as applied to the proxy gas supply plan for 2016. The Gas Costs inputs into Allowed Revenue will be updated within each annual Rate Adjustment proceeding.

d. Operating & Maintenance Costs: The values for 2017 and 2018 are determined as follows: (i) “Other O&M” and RCAM are combined, and the 2017 value is determined by applying the average rate of change in those costs from 2013 to 2016 to the 2016 forecast amount of “Other O&M” and RCAM; (ii) the 2018 amount for “Other O&M” and RCAM are determined by applying the same average rate of change to the 2017 value for those costs: (iii) the customer care/CIS costs are determined by applying the current forecast of customers within Exhibit D1, Tab 10, Schedule 3, to the per-customer amount set out in the updated EB-2011-0226 Template; (iv) the DSM amounts are determined by applying a 2% per year inflation amount to the 2016 forecast budget; and (v) the pension/OPEB amounts for 2017 and 2018 are those that are found within the Mercer studies attached to Exhibit D1, Tab 16, Schedule 1. The forecast level of costs for customer care/CIS, DSM and pension/OPEBs will be updated within the 2017 and 2018 Rate Adjustment proceedings.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

e. Depreciation Costs: The values for each year are determined based upon use of the 2016 forecast Capital Budget impacts (as a reasonable estimate of impacts for each of 2017 and 2018), using the proposed updated depreciation rates.

f. Fixed Financing Costs: The forecast values for 2017 and 2018 of the administration, extension and standby fees associated with the Company's committed credit facility are filed in updated Exhibit E1, Tab 2, Schedule 2.

g. Municipal and Property Taxes: The values for 2017 and 2018 are determined by calculating the average rate of change in these costs from 2013 to 2016, and applying that rate of change to the 2016 value, and then to the resulting forecast 2017 value.

h. Other Operating Revenue: The values for 2017 and 2018 are held flat at the 2016 level.

i. Income Taxes: The values for 2017 and 2018 are based on the forecast of income tax rates within Exhibits D3/D4/D5, Tab 1, Schedule 1, as applied to forecast utility taxable income, using the Allowed Revenue inputs described above.

<u>Rate Adjustment process to set rates for each year from 2014 to 2018</u>

15. The Company's proposal to set rates for 2014, based on the Allowed Revenue amount for 2014, is set out at Exhibit A2, Tab 2, Schedule 1.

16. In order to set rates for 2015 to 2018, Enbridge proposes to follow a similar annual rate adjustment process as was used during the 1st Generation IR term. That is, Enbridge proposes to present the Board with an annual update of volumes, which when applied to existing rates, will determine the revenue forecast at existing rates. Enbridge will then compare the pre-determined Allowed Revenue for 2015 to 2018 as approved by the Board in this case, to the revenue forecast at existing rates to determine the revenue sufficiency or deficiency to be applied as a rate adjustment for the year being reviewed.

17. Normally, total volumes are determined by multiplying the average use forecast by the number of small volume customers and adding in total forecast industrial or other volumes. Enbridge believes the process may be somewhat streamlined by approving the customer additions forecast numbers for each year of the IR term within this proceeding (for 2014 to 2018). That is also consistent with the fact that the cost forecasts being presented for approval in those proceedings are premised in part on the customer additions forecasts being used. As a result, the Company proposes that there will be no updating of the customer additions forecast as part of the annual Rate Adjustment proceedings. Instead, the total volume forecast will be calculated using the approved customer additions.[2]

18. Finally, as in the 1st Generation IR term, Enbridge proposes to annually file and present an update of its gas supply plan. This Application presents estimates and assumptions regarding the supply and transportation contracting conditions that are expected to prevail based on current information. However, market changes over the course of the 2014 to 2018 period as a result of the completion of the GTA

[2] Note, however, that the Customer Care/CIS Settlement Agreement requires that EGD adjust the number of average unlocks each year for the determination of Customer Care/CIS costs that are to be adjusted each year through the Rate Adjustment proceedings.

Reinforcement project, and uncertainties with respect to the TCPL Mainline may be material. An annual update of the gas supply plan has the advantage of capturing these market changes as they occur during the course of the IR term and benefits consumers by ensuring that the most appropriate contracting for upstream supplies is in place for each year. Once the annual gas supply plan has been approved, any variances from the annual plan would be captured in the PGVA and cleared within the normal course of the QRAM process.

19. Under this approach, risks for ratepayers and shareholders are reduced by annually reviewing volume forecasts. Specifically, since the volume forecast depends on the forecast annual degree days, an annual review and update will ensure that rates are set using the most up to date information using the Board Approved methodology for degree days. This will minimize the probability that volumes, and therefore rates, are set on an irrelevant weather basis.

20. To effect the setting of rates for 2015 to 2018, Enbridge proposes to file annual Rate Adjustment applications setting out:
    a. The approved final Allowed Revenue amount for the rate year;
    b. Forecast volumes for the rate year as determined by a degree day forecast, average use forecast, and other volume forecast;
    c. An updated gas supply plan;
    d. Updated Allowed Revenue amounts for Customer Care/CIS costs (calculated in accordance with the EB-2011-0226 Settlement Agreement) and pension/OPEB costs, which will replace the relevant amounts within the Allowed Revenue for that year;
    e. Any Z-Factor request, if necessary;

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

f. Proposed deferral and variance accounts for the rate year, including any forecast amounts for clearance, and the methodology for any proposed clearance of deferral or variance accounts;
g. A draft rate order; and
h. A rate handbook and supporting documentation explaining how rates have been adjusted.

21. As was the case for the 1st Generation IR period, the Company submits that a final rate order would need to be issued by December 15th, for any required rate adjustment to take effect by January 1st of the following year.

22. In order to accommodate a final rate order by December 15th, the Company proposes to file its rate adjustment application (without the supporting evidence) for each year by September 1st of the prior year, which will allow for the necessary administrative processes and notices to be produced.

23. Similar to the 1st Generation IR term, Enbridge will file the evidence in support of its rate adjustment applications by October 1st of each year. This will allow for the supporting evidence to be the most up-to-date and detailed information available in relation to rates for the following year. This timing will allow time enough for the Board and stakeholders to review the requested rate adjustment, pose interrogatories, and if necessary conduct a hearing, prior to the Board releasing a decision.

24. The Company has also proposed the inclusion of an Earnings Sharing Mechanism ("ESM") as part of this Customized IR proposal. As was the case for the 1st Generation IR proposal, Enbridge proposes to prepare and file and ESM calculation that pertains to each year of the plan following the release of its

Audited Financial Statements for the particular Fiscal Year. Enbridge will file an application containing this information with a proposal for clearance of any amount in the ESMDA and amounts in all other Board Approved deferral and variance accounts at that time.

25. For more information on the Company's proposed ESM, please refer to Exhibit A2, Tab 7, Schedule 1. For more information on other annual reporting related to performance measurement, and on the proposed Sustainable Efficiency Incentive Mechanism, please refer to Exhibit A2, Tab 11, Schedules 2 and 3.

Rate Design Changes during the Customized IR Term (2014 to 2018)

A) Energy Services

26. Gas utilities need rate design flexibility to respond to changing marketplace needs. The gas utilities accomplish this goal in two ways: a) by developing new rates and services, or b) by making specific changes to existing rates.

27. The unbundled rates and services that the Company has developed as part of the Natural Gas Electricity Interface Review ("NGEIR") generic proceeding (EB-2005-0551) are an example.

28. If the rate-related changes are minor in nature and customer impacts are minimal, the OEB's approval process could be included as part of the annual rate setting filing. However, if the rate-related changes are significant and warrant a longer review period, the Company will file a separate rate change application on a sufficiently timely basis.

B) Miscellaneous and Non-Energy Services

29. Enbridge proposes that should Enbridge need to change or introduce new miscellaneous or non-energy services during the IR plan period, the Company will seek approval for the changes and provide the Board with supporting evidence.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

ENBRIDGE CUSTOMIZED IR APPLICATION
PROCESS AND TIMING

Material circulated at the October 11, 2013 Information Session is attached as Attachment A and Attachment B.

Witness: K. Culbert

Summary

EB-2012-0459 : Enbridge Customized IR Application : Process and Timing

2014 Rate Application

- set final 2014 Rates

- set preliminary 2015 to 2018 Rates, the following components of Allowed Revenue for each year are fixed (and not subject to later adjustment):

    - most of the O&M budget (Other O&M and RCAM costs)
    - (for 2015 and 2016) forecast rate base amounts for everything other than gas supply related items
    - (for 2015 and 2016) depreciation and amortization expenses
    - the forecast ROE %, and cost rates for all other capital structure components
    - fixed financing costs
    - municipal and other taxes
    - miscellaneous operating revenues and income
    - income tax rates

2015 – 2018 Rate Adjustment Applications

- to set final Rates for each year; very similar to Rate Adjustment Applications within 1st Generation IR model

- Application to be filed by the end of September for the following year

- updates made to the following components of Allowed Revenue (as has been the case in the 1st Generation IR term):

    - the volumetric forecast, gas supply plan, revenue, gas cost and gas in storage/working cash forecast impacts will be updated using the degree day methodology approved within this rate application.
    - any income tax impacts from volumetric and gas supply plan updates will be updated.
    - O&M costs related to Customer Care, DSM and Pension/OPEB, using the most current forecasts

- updated items will replace the relevant amounts within the Preliminary Allowed Revenue for the subject year

2017 Rate Adjustment Application (Phase I)

- to update capital spending forecast for 2017 and 2018; will be filed by April 30, 2016
- update made to the following components of Allowed Revenue :
  - 2017 and 2018 forecast capital spend / rate base and related impacted items of depreciation expense,
  - income tax expense
  - total cost of capital
- updated items will replace the relevant amounts within the Preliminary Allowed Revenue amounts for 2017 and 2018

EGD 2014-2018 Customized IR Rate Application
2014 through 2018 Allowed Revenue Amounts
to be determined on a Final and Preliminary basis

Line No.		Col. 1 2014, 2015, 2016 Treatment	Col. 2 2014 Total Preliminary & Final Amounts	Col. 3 2015 Total Preliminary & Final Amounts	Col. 4 2016 Total Preliminary & Final Amounts	Col. 5 2017, 2018 Treatment	Col. 6 2017 Total Preliminary & Final Amounts	Col. 7 2018 Total Preliminary & Final Amounts
			($Millions)	($Millions)	($Millions)		($Millions)	($Millions)
	Cost of Capital							
1.	Rate base	A)	4,442.1	4,797.6	5,524.4	B)	5,736.6	5,906.1
2.	Required rate of return %	C)	6.74%	6.90%	7.02%	D)	7.04%	7.11%
3.			299.6	330.8	387.6		403.8	419.9
	Cost of Service							
4.	Gas costs	E)	1,550.9	1,606.8	1,632.5	E)	1,632.5	1,632.5
5.	Operation and maintenance	F)	425.3	428.5	439.5	F)	450.5	461.8
6.	Depreciation and amortization	G)	262.8	276.6	303.9	H)	313.4	322.1
7.	Fixed financing costs	I)	1.9	1.9	1.9	I)	1.9	1.9
8.	Municipal and other taxes	I)	41.2	43.1	45.5	I)	47.9	50.4
9.			2,282.1	2,356.9	2,423.3		2,446.2	2,468.7
	Miscellaneous operating rev & income							
10.	Other operating revenue	I)	(40.5)	(40.9)	(41.2)	I)	(41.2)	(41.2)
11.	Other income	I)	(0.1)	(0.1)	(0.1)	I)	(0.1)	(0.1)
12.			(40.6)	(41.0)	(41.3)		(41.3)	(41.3)
	Income taxes on earnings							
13.	Excluding tax shield	J)	67.5	56.3	52.9	K)	58.8	67.9
14.	Tax shield provided by int. exp.	J)	(39.5)	(42.5)	(48.4)	K)	(50.2)	(52.1)
15.			28.0	13.8	4.5		8.6	15.8
	Taxes on deficiency							
16.	Gross sufficiency / (deficiency) - with CIS/CC		13.6	(20.6)	(106.4)		(147.7)	(192.1)
17.	Net sufficiency / (deficiency) - with CIS/CC		10.0	(15.2)	(78.2)		(108.6)	(141.2)
18.			(3.6)	5.5	28.2		39.1	50.9
19.	Sub-total Allowed Revenue		2,565.5	2,666.0	2,802.3		2,856.4	2,914.0
20.	Cust Care Rate Smoothing Var. Adj.		(2.9)	(1.1)	0.8		2.9	5.0
21.	**Allowed Revenue**		2,562.6	2,664.9	2,803.1		2,859.3	2,919.0
	Revenue at existing Rates							
22.	Gas sales	L)	2,318.0	2,404.3	2,464.5	L)	2,480.3	2,496.2
23.	Transportation service	L)	252.4	229.6	217.1	L)	211.1	205.0
24.	Transmission, compr. & storage	L)	1.8	1.8	1.8	L)	1.8	1.8
25.	Rounding adjustment		0.1	0.1	-		-	0.3
26.	Total		2,572.3	2,635.8	2,683.4		2,693.2	2,703.3
27.	**Gross revenue sufficiency / (deficiency)**		9.7	(29.1)	(119.7)		(166.1)	(215.7)

2014-2016 Treatment Notes
A) Forecast final amounts set in the 2014 proceeding, other than annual gas supply plan update impacts filed in Sept applications.
C) Forecast ROE % and debt cost rates set in the 2014 proceeding, however annual gas supply plan updates will impact the capital structure mix.
E) Gas costs to be updated annually to match required annual volume and gas supply plan forecast.
F) Forecasts set in the 2014 proceeding with updates for cust-care/CIS, DSM, and pension/OPEB to be filed in Sept applications.
G) Forecast amounts set in the 2014 rate proceeding.
I) Forecast amounts set in the 2014 rate proceeding.
J) Forecast amounts set in the 2014 rate proceeding, other than impacts resulting from annual volumetric and gas supply plan updates.
L) Forecast revenues to be filed in Sept applications to incorporate approved rates and annual volume and gas suply plan updates.

2017-2018 Treatment Notes
B) 2017 & 2018 to be updated in April of 2016 for capital forecast re-fresh, in addition to annual gas supply plan update impacts filed in Sept applications.
D) ROE % and debt cost rates fixed for each year, however the capital re-fresh and annual gas supply plan updates will impact the capital structure mix.
E) Gas costs to be updated annually to match required annual volume and gas supply plan forecast.
F) Forecasts set in the 2014 proceeding with updates for cust-care/CIS, DSM, and pension/OPEB to be filed in Sept applications.
H) These preliminary estimates to be updated in April of 2016 in relation to the capital forecast re-fresh for 2017 & 2018.
I) Forecast amounts set in the 2014 rate proceeding.
K) For 2017 & 2018 forecast tax rates set in this proceeding, tax related amounts to be updated for capital re-fresh impacts in April 2016 and annual volume and gas supply plan updates filed in Sept applications.
L) Forecast revenues to be filed in Sept applications to incorporate approved rates and annual volume and gas suply plan updates.

This page was provided at the October 11th information session and is a simple summary of EGD (all other) and (CIS/Customer Care) revenue requirement amounts which must be and are determined separately as shown at Exhibits F1.T1.S2 & F1.T1.S3.App.A.

Z-FACTOR

Overview

1. For its Customized IR Plan, Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") proposes that Z-factors should continue to apply to protect the Company and ratepayers from unexpected costs that are outside of management's control. This is consistent with the views expressed in the Natural Gas Forum Report, the Ontario Energy Board ("Board") Staff Discussion Paper issued in relation to IR plans for gas utilities, and the recently issued Renewed Regulatory Framework for Electric Utilities ("RRFE") Report.

2. The Company believes that enhancements should be made to the Z-factor description and criteria that applied to Enbridge during its 1st Generation IR term. This will make the identification and evaluation of potential Z-factors requests more clear and consistent.

3. To accomplish these goals, Enbridge proposes the following description and criteria for Z-factors within its Customized IR Plan:

   A Z-factor is a non-routine adjustment intended to safeguard customers and the gas utility against unexpected cost increases or cost decreases that are outside of management control. A cost increase or decreases will be treated as a Z-factor if it meets all four of the following criteria:

   (i) Causation: The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine cause.

(ii) Materiality: The cost at issue must be an increase or decrease from amounts included within the Allowed Revenue amounts upon which rates were derived. The cost increase or decrease must meet a materiality threshold, in that its effect on the gas utility's revenue requirement in a fiscal year must be equal to or greater than $1.5 million.

(iii) Management Control: The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management is unable to prevent by the exercise of due diligence.

(iv) Prudence: The cost subject to an increase or decrease must have been prudently incurred.

The criteria described above are the only criteria, implicit or explicit, for Z factor treatment.

Background

4. In the Natural Gas Forum ("NGF") Report (2005), the Board acknowledged that Z-factors are proper features of IR plans for Ontario gas utilities, to be used in

> Limited, well-defined and well-justified cases and to provide for a non-routine rate adjustment intended to safeguard customers and the utility against unexpected events outside of management control (at pages 4 and 30).

5. Board Staff issued a Discussion Paper in 2007 (Staff Discussion Paper on an Incentive Regulation Framework for Natural Gas Utilities), which was intended to

set out a potential incentive regulation framework that was consistent with the key parameters addressed and endorsed in the NGF Report. In that Discussion Paper, Board Staff described a Z-factor as follows:

> A Z factor provides for non-routine rate adjustments intended to safeguard customers and the gas utility against unexpected events that are outside of management's control. Examples include changes in tax rules and natural disasters.

6. The Board Staff Discussion Paper then set out criteria around the amounts for which Z-factor treatment is sought, should meet, in four categories:

Criteria	Description
Causation	Amounts should be directly related to operational requirements created by the Z factor event. A significant portion of the expenditure should be demonstrably linked to addressing new operational requirements, as opposed to upgrading current procedures and systems to gain efficiencies under the guise of addressing the event. At least 75% of the amount should be directly and demonstrably linked to the Z factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amount must have a significant influence on the operation of the gas utility; otherwise it should be expensed in the normal course and addressed through organizational productivity improvements. Board staff recommends that the threshold amount be $1.0 million* for individual items.
Inability of Management to Control	To qualify for Z factor treatment, the amount must be attributable to some event outside of management's control (i.e., the event causing the amount must be exogenous to the utility).
Prudence	The amount must have been prudently incurred.

7. The question of whether to include a Z-factor mechanism within Enbridge's 1st Generation IR plan arose soon after the Board Staff Discussion Paper was issued.

8. Issue 6.1 in Enbridge's EB-2007-0615 proceeding, which set the parameters for the Company's 1st Generation IR plan, asked "What are the criteria for establishing Z-factors that should be included in the IR plan?" This issue was completely settled. In the EB-2007-0615 Settlement Agreement, all parties accepted the appropriateness of a Z-factor as part of Enbridge's 1st Generation IR plan. All parties agreed upon the following criteria to apply for Z-factor approvals in the 1st Generation IR plan:
   i. the event must be causally related to an increase/decrease in cost;
   ii. the cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps;
   iii. the cost increase/decrease must not otherwise reflected in the per customer revenue cap;
   iv. any cost increase must be prudently incurred; and
   v. the cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event).

9. In Enbridge's experience, the interpretation of the above criteria over the five years of the Company's 1st Generation IR term has led to confusion and uncertainty around what costs would qualify for Z-factor treatment. This has arisen in three ways:

   a) The reference to a discrete "event" (in the first criterion) leads to a requirement to pinpoint a single development or occurrence which has caused increased or decreased costs. In Enbridge's view, there may be more than one item or event that leads to changes in costs from what was known and included within Allowed Revenue amounts set at the start of an IR term.

b) The requirement (in the second criterion) that the "cost" associated with the Z-factor request be beyond the control of the Company's management leads to discussion about how management might be able to impact or affect the costs at issue. The implication is that if management has any such control, then the costs are not recoverable. In Enbridge's view, this makes it unreasonably difficult to qualify for Z-factor recovery. By their nature, most costs incurred by a utility (including costs from entirely exogenous events like new regulatory/code requirements or natural disasters) are at least partly within management's control. The key examination in relation to "management control" should be upon whether management could have entirely prevented the costs. The subsequent determination of whether such costs should be recoverable as a Z-factor lies in whether they are prudently incurred in response to exogenous events.

c) The requirement (in the second criterion) that the cost not be "a risk in respect of which a prudent utility would take risk mitigation steps" is difficult to understand and interpret. This phrase, which was first seen in the Union Gas 1st Generation IR model Settlement Agreement, introduces the notion of "risks", which are not otherwise referenced or defined within the Z-factor criteria. In Enbridge's view, the inclusion of this phrase has led to confusion around what is covered, and not, by the Z-factor criteria in the 1st Generation IR model.

Enbridge's Proposed Z-factor for its Customized IR model

10. Considering the difficulties experienced with the interpretation of the Z-factor criteria within Enbridge's 1st Generation IR plan, the Company has created a refined statement of the nature and criteria for Z-factors to apply within Enbridge's Customized IR Plan. In doing this, the Company has sought to be consistent with the direction and suggestions included in the NGF Report and the Board Staff Discussion Paper.

11. Enbridge's Settlement Agreement for its 1st Generation IR plan did not contain any overall statement describing the role and purpose of a Z-factor within the IR model. Enbridge believes that this would be helpful, and provide clarity and context to the requirements that must be met in order to obtain Z-factor treatment.

12. For the purpose of its Customized IR Plan, Enbridge defines a Z-factor as follows:

> A Z-factor is a non-routine adjustment intended to safeguard customers and the gas utility against unexpected cost increases or cost decreases that are outside of management control.

13. This phrasing clearly sets out that Z-factors are only intended to apply in relation to costs that arise from causes that are beyond the control of the utility's management. That is consistent with the Board's description of Z-factors, as seen in the NGF Report.

14. In keeping with the approach suggested by Board Staff, and with the approach included within its 1st Generation IR plan, Enbridge proposes to maintain a set of criteria that amounts claimed for Z-factor recovery must meet. These are organized into the same four categories as suggested in the Board Staff Discussion Paper.

In order for amounts to be considered for recovery as a Z-factor, Enbridge is proposing that Z-factor event amounts must satisfy the criteria in all four categories.

15. The first category, referred to as "Causation", would require that

> The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine cause.

16. This criterion makes clear that the costs at issue must be driven by an unexpected "cause". Enbridge believes that this is a more appropriate requirement, as compared to linking the costs to a particular "event", because the term "cause" will take away focus on a discrete item or circumstance and allow for cases where there may be a collection of related "events" that are the "unexpected, non-routine cause" of a cost increase or decrease. The recognition that the utility need only show that a "significant portion" of the cost increase or decrease claimed be linked to the unexpected non-routine cause is consistent with the Board Staff Discussion Paper.

17. The second category, referred to as "Materiality", would require that

> The cost at issue must be an increase or decrease from amounts included within the Allowed Revenue amounts upon which rates were derived. The cost increase or decrease must meet a materiality threshold, in that its effect on the gas utility's revenue requirement in a fiscal year must be equal to or greater than $1.5 million.

18. The materiality threshold proposed is the same as was in place for Enbridge's 1st Generation IR plan (and is higher than proposed in the Board Staff Discussion Paper). Similarly, the requirement that the costs at issue not be costs that are part of the Allowed Revenue amounts approved at the beginning of the IR term, is maintained.

19. The third category, referred to as "Management Control", would require that

> The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management is unable to prevent by the exercise of due diligence.

20. These criteria make clear the requirement that the cause of the costs at issue must be beyond the control of utility management. That is consistent with the requirements set out in the Board Staff Discussion Paper. It avoids the debate arising from the wording of the 1st Generation IR plan as to whether the "costs" are within "management control", and more appropriately focuses upon whether the "cause" of the "costs" is within management control. Additionally, the confusing requirement from the 1st Generation IR model that "the cost" not be "a risk in respect of which a prudent utility would take risk mitigation steps" is replaced by a more comprehensible requirement that the cause of the cost increase must be "a cause that utility management is unable to prevent by the exercise of due diligence."

21. The fourth category, referred to as "Prudence", would require that

> The cost subject to an increase or decrease must have been prudently incurred.

22. This requirement is consistent with the Board Staff Discussion Paper and with the criteria in the Company's 1st Generation IR plan.

23. As was the case for Z-factors within Enbridge's 1st Generation IR plan, the criteria described above are the only criteria, implicit or explicit, for Z-factor treatment. A cost increase or decrease that satisfies all four criteria will qualify for Z-factor

treatment. There is no criterion that requires consideration of the Company's overall spending or earnings in the year in which a Z-factor is requested.

24. Finally, it is recognized and understood that the manner in which the Z-factor is recovered through rates as well as the resulting rate impacts, are to be considered in any application for Z-factor relief.

COST OF CAPITAL TREATMENT

1. This evidence sets out Enbridge's proposal and rationale for the treatment of the Cost of Capital in this Customized IR plan.

2. Enbridge has considered each of the following areas with respect to this proposal:
   a. Capital structure through the IR term
   b. Return on Equity ("ROE") through the IR term
   c. Cost of Capital for ESM purposes

Capital Structure

3. Through this Application, Enbridge proposes to fix the capital structure ratios that will apply through the term of the Customized IR plan for ratemaking purposes.

4. As a result of the 2013 Test Year Rebasing case (EB-2011-0354), the Board determined that Enbridge's equity ratio should remain at 36%. Enbridge proposes to maintain this equity ratio for ratemaking purposes for the duration of the IR term.

5. For the 2014 to 2018 period, Enbridge's use of long term debt, short term debt, and /u
preferred shares during the IR term have been developed according to the pace of required capital spending and the timing for cash flow needs. The financing plan for 2014-2018 is filed at Exhibit E1, Tab 2, Schedules 1 and 2, and sets out the /u
determination of the amounts, timing, and costs for each of long term debt, short term debt, and preferred share financing, and results in the following capital structure derived percentages:

Witnesses: K. Culbert
R. Fischer
M. Lister
M. Suarez-Sharma

Capital Structure Component	2014 Weight	2015 Weight	2016 Weight	2017 Weight	2018 Weight
Equity	36%	36%	36%	36%	36%
Long term debt	59.37%	61.41%	61.31%	61.49%	61.28%
Short term debt	2.34%	0.49%	0.87%	0.76%	1.02%
Preferred shares	2.29%	2.10%	1.82%	1.75%	1.70%

6. It should be noted that Enbridge's acceptance of the 36% for the equity ratio for the duration of the IR term is not an acceptance that this ratio meets the Fair Return Standard. While Enbridge is implementing this equity ratio for the duration of the Customized IR term, the Company reserves its rights to apply, at a later date, for an appropriate equity ratio that meets the Fair Return Standard in conjunction with a given ROE level and to take any position deemed appropriate if a generic Cost of Capital proceeding is convened.

7. Where the required level of capital spending is altered for purposes of determining eventual approved rates, the planned ratios of long and short term debt may be affected which could require a re-forecast of planned debt issuances.

<u>ROE through the IR term</u>

8. For ratemaking purposes, Enbridge proposes to include forecasted ROE levels for each year of the IR plan into the determination of Allowed Revenue for each fiscal year of the IR term. That is, a different ROE level will apply for each of 2014 to 2018, inclusive.

9. The forecasted ROE levels for 2014 through 2018 can be found at Exhibit E2, Tab 1, Schedules 1 and 2. /u

Witnesses: K. Culbert
R. Fischer
M. Lister
M. Suarez-Sharma

10. It is appropriate and reasonable to include the ROE forecasts directly into the derivation of the Allowed Revenue, as the cost of capital is a legitimate utility cost. In a traditional 'I-X' framework, forecast cost of capital is typically not included as it is believed that the inflation factor provides, at least in part, some compensation for changes in interest rates, which otherwise affect the level of Allowed ROE. In this proposed Customized IR approach, however, there is no explicit forecast of inflation, only a forecast of the costs that contribute to the Allowed Revenue. As such, it is reasonable that the Allowed Revenue forecasts should include representation for the forecast costs of capital that the utility will bear during the IR term.

11. EGD also considered an approach that would float the ROE, so that any updated ROE value would be used each year. That ROE value would be determined annually according to the Board Approved Formula at the time that the Formula output is known (i.e., approximately November of each year).

12. This alternative has the advantage of annually representing a true reflection of the cost of capital into rates, but the disadvantage of being another item for update and adjustment through the IR term. There is also difficulty with the timing of this approach, since a November date for ROE updates would make it a challenge to implement rates by January 1st of the following year. Given these disadvantages, Enbridge believes this alternative is not best suited to incentive regulation.

<u>Cost of Capital for ESM purposes through the IR term</u>

13. Discussion of the Company's ESM proposal can be found at Exhibit A2, Tab 7, Schedule 1. Enbridge proposes that if its actual ROE is more than 100 basis points above the Board's ROE Formula for that year, then it will equally share any

earnings above that level with ratepayers, subject to the Off Ramp Criteria at 300Bp or greater ROE (Exhibit A2, Tab 6, Schedule 1).

14. As explained in that evidence, Enbridge proposes that the Board's ROE Formula used to calculate the annual ESM amount should be annually adjusted according to the ROE formula set out in the Board's 2009 Cost of Capital report.

15. Enbridge proposes leaving its equity ratio unchanged for the purposes of calculating the amounts for ESM. Enbridge will leave the equity ratio unchanged at 36% even if there is a change to this amount as a result of any Cost of Capital review. While it would be ideal to calculate ESM on the basis of the most up to date cost of capital parameters in order to obtain a true reflection of the Fair Return Standard, this would be very difficult to implement. Changing the equity ratio for ESM purposes relative to what is used for ratemaking purposes would require the Company to estimate what financing would otherwise have taken place had rates been set to use an equity ratio different from 36%. This would require estimates for the amounts, timing, and costs of both short-term and long-term debt, and would therefore introduce layers of complexity, and potential controversy, into the calculation of earnings sharing.

Witnesses: K. Culbert
R. Fischer
M. Lister
M. Suarez-Sharma

OFF-RAMP CRITERIA

1. An off-ramp is intended to provide a safeguard against unexpected results in the operation of the IR plan. Enbridge proposes to maintain the off-ramp provision from the 1st Generation IR Plan, which is triggered on the occurrence of a 300 basis point or greater variance in weather normalized utility earnings, above or below the amount calculated annually by the application of the ROE Formula. To be clear, the ROE formula to be used will be the ROE formula set out in the Board's 2009 Cost of Capital report.

2. Off-ramps are designed to protect both the Company and customers during the IR term. In this way, the Company is protected from an erosion of its financial position sufficiently serious to impact the operation of the utility or to limit adverse impacts to its creditworthiness. Similarly, a symmetric off-ramp with an upper bound addresses situations where the utility's earnings are extraordinarily high.

3. If such conditions prevail, then Enbridge will file an application with the Board, with appropriate supporting evidence, for a review of the Customized IR plan. The review will be prospective only (i.e. will not result in any confiscation of over-earnings, nor any collection of earnings shortfalls).

4. On such an application, Enbridge and stakeholders would be free to take any position they deem appropriate with respect to the review or the review process, including, without limitation:

    I. proposing that any component IR plan should be changed;
    II. proposing that the IR plan should be terminated; or
    III. any other position as Enbridge or stakeholders consider relevant.

Witnesses: R. Fischer
M. Lister

EARNINGS SHARING MECHANISM

1. The Company proposes an Earnings Sharing Mechanism ("ESM") for the Customized IR term that will share earnings with ratepayers above a set threshold. The manner in which this is determined is by calculating the actual ROE earned by the Company in a given year, and comparing that to the ROE level determined by the application of the Board's 2009 ROE Formula ("Allowed ROE"). Where the actual ROE is more than 100 basis points above Allowed ROE, then the associated over-earnings will be shared equally with ratepayers. Enbridge will not share the first 100 basis points of over-earnings. The proposed ESM is non-symmetrical, such that ratepayers will not be responsible for sharing (paying for) any level of under-earnings.

2. With Enbridge ("Enbridge" or the "Company") seeking a Customized IR model in this application, the main purpose of proposing an ESM is to give greater credibility to Enbridge's cost forecasts to the OEB and stakeholders. That is, the ESM provides an assurance to the Board and stakeholders that Enbridge's cost forecasts are reasonable. If Enbridge were to materially underspend relative to the forecast in any given year, then there would be a disbursement to customers of a share of the savings. Alternatively, if Enbridge were to materially overspend relative to the forecast, customers would not bear any incremental financial burden. Effectively, the ESM serves to assure that the utility does not earn excessive returns at ratepayer expense.

3. While the proposed ESM is intended to provide assurances to the Board and stakeholders as to the validity and credibility of Enbridge's cost forecasts, Enbridge also feels it is important to maintain the appropriate incentives with the ESM design.

Witnesses: R. Fischer
M. Lister
K. Culbert

That is, it is widely recognized that an ESM design that provides little potential for over-earning to the utility also damages incentives to pursue enhanced productivity performance. Enbridge believes that retaining the first 100 basis points of over-earning will provide the right quantum of incentive, while also ensuring customers are not unduly burdened by any material cost forecast error.

4. Enbridge believes that this ESM proposal represents a reasonable safeguard for customers, while still retaining an appropriate measure of incentives for the utility. Furthermore, this ESM proposal is consistent with the 1st Generation plan, with which there is experience and understanding.

5. Enbridge believes this ESM proposal is reasonable given that no productivity stretch factor has been proposed within the IR plan. If stakeholders were to insist on the application of a productivity stretch factor, then Enbridge would not support the continuation of an ESM. In other words, if ratepayers were to be given assured recovery of a portion of additional productivity gains (beyond what is included within the filed budgets), then Enbridge should not have to share any further gains with ratepayers.

6. In terms of the functional workings of the ESM, Enbridge proposes to continue to use a methodology substantially similar to that which was established in the Settlement Agreement for Enbridge's 1st Generation IR plan. Specifically, the ESM would function as follows:

   (i) If in any calendar year, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated annually by the application of the Board's ROE Formula in any year of the IR Plan, then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge and its ratepayers;

(ii) For the purpose of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;

(iii) All revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculation.

7. To be clear, Enbridge proposes that the Board's ROE Formula used to calculate the annual ESM amount should be the ROE Formula that was spelled out in the Board's 2009 Cost of Capital Report.

8. As was the case for the 1st Generation IR plan, Enbridge proposes to prepare and file an ESM calculation that pertains to each year of the Customized IR term following the release of its Audited Financial Statements for the particular fiscal year. Amounts to be credited to ratepayers will be included within the Earnings Sharing Mechanism Deferral Account ("ESMDA"). Each year, Enbridge will file an Application setting out its proposal for the clearance of amounts within the ESMDA and amounts in all other Board Approved deferral and variance accounts. Within that Application, Enbridge will also provide the Performance Measurement

Witnesses: R. Fischer
M. Lister
K. Culbert

information that it proposes to provide annually, as described at Exhibit A2, Tab 11, Schedule 2.

REBASING FILING REQUIREMENTS

1. Enbridge's expectation is that there will be a rebasing or other cost of service based application at the end of the IR term. This application will relate to the 2019 Test Year.

2. The following paragraphs describe Enbridge's expectations for a 2019 Test Year application that would occur in 2018.

3. Enbridge will file a full cost of service application, including three fiscal years of information for the Board's review, and for the determination of 2019 rates. The three years included for review are:

   a. The 2017 Historical Year would be populated with actual results or a combination of actual plus forecast dependent upon the filing date for the Company's evidence. That is, until the Enbridge Board of Directors approves the release of the 2017 financial results, the Company would not be able to file (final) actual results. Board of Directors approval would normally occur in mid-to-late February of the year following the year under review or, in this case, February of 2017;
   b. The 2018 Bridge Year would be populated with zero months actual plus 12 months of forecast information, usually referred to as '0+12'. Again, the timing of the filing of the Company's evidence would influence whether any actual data could be included in the Bridge Year (for example, 2+10 or 3+9 evidence); and,
   c. The 2019 Test Year would be populated with the Company's budget for that year.

Witnesses: R. Fischer
M. Lister

4. In addition, as part of its 2019 application, the Company will file the Performance Measurement reporting that is detailed at Exhibit A2, Tab 11, Schedule 2.

Witnesses: R. Fischer
M. Lister

INCENTIVE RATEMAKING REPORT

Prepared for: Enbridge Gas Distribution

CONCENTRIC ENERGY ADVISORS, INC.
JUNE 28, 2013

INCENTIVE RATEMAKING REPORT

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Concentric Energy Advisors, Inc. is an employee-owned management consulting and financial advisory firm focused on the North American energy industry. We offer a broad range of advisory and support services to clients including private and municipal utilities, governmental agencies, financial institutions and industry investors.

Concentric's regulatory experts are closely attuned to the latest rate-setting practices, policies and trends in North America, including the interface of integrated resource planning with ratemaking, the application of rate designs to achieve policy objectives, resource planning and development to achieve environmental and economic policy goals, and alternative regulation mechanisms, including vertical segregation, the introduction of competitive forces into regulated markets, and efficiency-based regulatory incentive mechanisms.

Our ratemaking services range from high level rate case assistance (e.g., case management, stakeholder communications, witness training) to addressing specific technical rate case requirements (e.g., revenue requirements, cash working capital, cost of service studies, marginal cost studies and pricing, rate design, tariff design, cost of capital, attrition of earnings, management prudence, and rate base (including the fair value of rate base assets)). Concentric's consultants also have experience in alternative ratemaking proceedings, including incentive ratemaking approaches, revenue decoupling, capital spending recovery mechanisms, and inflation adjustment mechanisms.

Concentric's regulatory and financial experts have appeared as expert witnesses in most U.S. and Canadian jurisdictions on ratemaking and policy-related issues. The firm is led by senior experts with experience from utilities, government, regulation and finance, supported by a team of consultants and analysts specializing in the financial, economic and technical analysis required for regulatory proceedings.

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APPENDICES

I. EXECUTIVE SUMMARY

This report summarizes the research and analysis conducted by Concentric Energy Advisors ("Concentric") for Enbridge Gas Distribution, Inc. ("Enbridge", "EGD," or the "Company") to assist with the development of the Company's proposed 2nd Generation Incentive Regulation ("IR") plan, which the Company is referring to as a "Customized IR" plan. Our work focused on assisting Enbridge with the development of a proposed plan that would be consistent with the Ontario Energy Board's ("OEB") objectives for such plans, recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs, including Enbridge's 1st Generation plan.

Incentivizing productivity is a key element of any IR plan. In order to promote productivity and efficiency in utility operations, the regulator, company and stakeholders all require an understanding of the baseline starting point, and realistic expectations for what is possible in the future. To create this baseline, Concentric conducted a series of analyses. First, we benchmarked Enbridge's performance across a variety of operating and financial metrics over the 2000 to 2011 period in relation to a group of gas distribution peer group companies. Second, we measured the productivity of the industry and Enbridge over the same period using a total factor productivity "TFP" analysis that measures the efficiency of a utility in converting all of its inputs (labour, capital and materials) into outputs (customers serviced). Third, we narrowed the scope of the examination to focus on O&M expenses only (excluding capital), with a partial factor productivity ("PFP") analysis. These TFP and PFP analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group[1] that could be utilized to test parameters for the Customized IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016[2] costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile.

Results from Concentric's cost benchmarking analysis indicate that EGD is among the most efficient of its industry peers, especially related to O&M and labour costs, although EGD's net plant costs per customer are at the higher end of the industry study group examined.

[1] The industry peer groups used for benchmarking and productivity analyses were similar, however some companies that were used in the benchmarking analysis were excluded from the productivity analyses due to data limitations.

[2] While Enbridge is proposing a five year term (2014 to 2018) for the Customized IR plan, Concentric's analyses focused on the 2014 to 2016 period, which corresponds to the period for which "final" Allowed Revenue amounts will be fixed in this proceeding.

Regarding trends in EGD's performance relative to the industry study group over the 2000 to 2011 period examined, Enbridge has generally sustained or improved its cost position in relation to its peers, including during the most recent IR plan period.

Concentric prepared separate TFP and PFP indexes for EGD, for an industry study group, and a seven company sub-group of the largest and fastest growing companies that more closely resemble Enbridge's profile. Productivity is specified as the difference between output growth and input growth, and a productivity index is calculated from annual changes. These results are summarized in Figure 1 for the entire period, and also broken out for the pre-IR period and during the IR period for comparison. The "during IR" period coincides with Enbridge's 1st Generation IR plan.

Figure 1: TFP and PFP Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Average Annual Growth Rates					
		Industry Study Group		Seven Company Sub-Group		EGD	
		TFP Growth Rate	PFP Growth Rate	TFP Growth Rate	PFP Growth Rate	TFP Growth Rate	PFP Growth Rate
Whole Period	2000-2011	-0.32%	-0.25%	-0.01%	-0.02%	-0.28%	0.50%
Pre-IR	2000-2007	0.19%	0.47%	0.43%	0.74%	-0.06%	0.44%
During IR	2007-2011	-1.22%	-1.52%	-0.78%	-1.33%	-0.66%	0.60%

Figure 1 demonstrates that over the entire 2000 to 2011 study period, the seven company sub-group TFP growth rate, -0.01%, is higher than EGD's TFP growth rate of -0.28%, and higher than the 25 company industry study group TFP growth rate of -0.32%. These results indicate that, in general, the largest and fastest growing companies were more efficient in terms of converting inputs to outputs, but at best, productivity was flat to negative over this period. However, the decline in EGD's TFP growth rate from 2000 to 2007 compared to 2007 to 2011 was less than the industry group's TFP growth rate decline and also less than the seven company sub-group's TFP growth rate decline. As a result, Enbridge outperformed both industry groups over the most recent period.

Over the entire 2000 to 2011 study period, the seven company sub-group PFP growth rate, -0.02%, is higher than the 25 company industry study group PFP growth rate, -0.25%, which indicates greater PFP growth for the seven company sub-group. For the same period of 2000 to 2011, EGD's PFP rate, 0.50%, is significantly higher than both the industry study group average and the seven company sub-group average, indicating that Enbridge was more productive than both groups in converting O&M inputs to customers serviced. PFP growth rates from 2007 to 2011 were less than PFP growth rates from 2000 to 2007 for both the industry study group and the seven company sub-group, however EGD's PFP improved by 0.16% between 2000 to 2007 and 2007 to 2011.

EGD's TFP and PFP improvement between 2000 to 2007 and 2007 to 2011 may be attributable to (a) the incentives for efficiency improvements that resulted from EGD's 1st Generation IR, and (b) EGD's relatively high output growth rate from 2007 to 2011, compared to industry study group or seven company sub-group companies.

The analysis of productivity provided by Concentric serves two roles in EGD's proposed Customized IR plan: (1) the seven company sub-group TFP was used to evaluate the sufficiency of an I-X rate path against EGD's projected costs; and (2) the seven company sub-group PFP was used to evaluate the productivity embedded in EGD's O&M expense projection. Concentric's benchmarking analysis demonstrated that EGD is currently an efficient utility and that EGD has continued to improve its performance relative to its industry peers, especially related to O&M costs. Furthermore, Concentric's productivity analysis demonstrated that EGD improved its productivity as measured by both TFP and PFP during the 1st Generation IR plan (2007 – 2011) compared to the pre-IR plan period (2000 to 2007) relative to performance of both the 25 company industry study group and the seven company sub-group during those same periods, which indicates that EGD made productivity improvements during the 1st Generation IR plan. This also suggests that the relatively "easy" productivity improvements that are often available at the onset of IR may not be as available to EGD in the 2nd Generation IR. While it is important that EGD continue to look for additional efficiency and productivity improvement opportunities, they may be more difficult for EGD to find. Based on Concentric's TFP and PFP analyses, Concentric recommends an X Factor of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan.

There are two common approaches to developing the inflation factor ("I Factor") used in I-X type formulas: (1) using a single macroeconomic index; or (2) using a composite I Factor. Concentric considered the benefits of the continued use of the existing GDP-IPI-FDD inflator versus a composite factor to evaluate the Allowed Revenue amounts for EGD's Customized IR plan. In doing so, Concentric researched a broad array of potential indices and examined their sources, components, and availability. Based on the availability of price indexes that more specifically reflect labour and capital costs, and the historical evidence that illustrates the potential for these cost indices to diverge from the general rate of inflation, we believe it is appropriate to utilize those more specific indices to reflect price changes in those specific inputs. We recommend a composite I Factor comprised of a weighted average of (1) the Ontario Average Hourly Wages (all employees) for labour-related prices, (2) Canada GDP-IPI-FDD for materials prices, and (3) Canada implicit price index for net gas distribution plant.

To test the reasonableness of EGD's 2014 to 2016 O&M forecast, Concentric performed two evaluations. First, Concentric compared EGD's 2014 to 2016 forecast O&M cost per customer to EGD's historical trend of O&M costs per customer and to the O&M cost per customer of the cost benchmarking study group. EGD's projected 2014 to 2016 O&M cost per customer is higher than recent history, but not by a significant amount, and is below the industry study group average. For the second analysis, Concentric compared EGD's 2014 to 2016 forecast O&M cost per customer with the O&M cost per customer that would be derived from applying the I-X growth rates from the PFP study. On balance, EGD's projected O&M costs are lower than the PFP I-X trajectory by approximately $12 million over the three years 2014 to 2016. EGD's projected O&M cost per customer is higher than the O&M cost per customer derived from applying the PFP I-X formula in 2014 and is lower than the O&M cost per customer derived by applying the PFP I-X formula in 2015 and 2016. The results of Concentric's analyses indicate that EGD's projected 2014 to 2016 O&M costs are reasonable based on a comparison to the benchmark utilities, and in relation to productivity from the seven company sub-group PFP analysis.

Concentric prepared a separate quantitative analysis of capital-related revenue requirements and revenues. The quantitative analysis for Concentric's assessment of EGD's proposed capital cost recovery approach is based on the results of models that Concentric developed to (a) determine the capital-related revenue requirements of EGD's projected rate base and plant balances during the 2014 to 2016 period, and (b) calculate the projected revenues during the 2014 to 2016 period. We prepared analyses of the following ratemaking approaches:

Rate Option 1: I-X revenue per customer adjustment mechanism
Rate Option 2: General Purpose Capital Tracker, combined with an I-X revenue per customer adjustment mechanism
Rate Option 3: Special Project Capital Tracker, combined with an I-X revenue per customer adjustment mechanism
Rate Option 4: Customized IR (EGD's Proposed Approach)

It is Concentric's assessment that an I-X escalation formula does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $141.5 million. An I-X escalation formula combined with a general purpose capital tracker mechanism also does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $88.2 million. Further, an I-X escalation formula combined with a special project capital tracker for the GTA and Ottawa reinforcement projects does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $51.2 million. Only Rate Option 4, a Customized IR plan with recovery of capital-related costs matched to EGD's projected capital-related revenue requirements adequately covers the costs of EGD's base capital spending and GTA and Ottawa reinforcement projects.

EGD also asked Concentric to review EGD's proposed earnings sharing mechanism ("ESM") and provide our perspective regarding the reasonableness of EGD's proposed ESM, given the overall structure of EGD's proposed program. Concentric understands that EGD is proposing an ESM with a deadband of 100 basis points above the authorized ROE, with a 50/50 sharing formula and a +/-300 basis point review trigger, the same as that approved for EGD's 1st Generation IR Plan. On balance, we conclude that EGD's proposed ESM provides an appropriate safeguard for customers and the utility, while continuing to provide ongoing incentives for productivity improvement. The deadband serves the purpose of incenting EGD to identify additional efficiencies, while the earnings sharing and re-opener trigger provide a safety mechanism to address large deviations in earnings. While we could argue that a 100 basis point deadband creates a diminished incentive compared to a wider deadband, and that a symmetrical ESM would better balance the risk and reward profiles of EGD and customers, EGD's performance under the 1st Generation IR (with the same ESM parameters) suggests that these issues are manageable, as customers benefited from earnings sharing in all 5 years of the Plan. Based on our research and industry experience, Concentric believes that EGD's ESM proposal is reasonable.

To evaluate EGD's proposed Customized IR plan as a whole, Concentric contrasted the total revenue recovered under two alternative rate recovery alternatives (I-X, and I-X plus Y factors for the GTA and Ottawa projects) versus Enbridge's projected O&M and capital related costs over the 2014 to 2016 period. The I-X rate option leads to a three-year cumulative shortfall of $126 million; the I-X plus Y factor option produces a deficiency of $35.7 million that also does not provide for adequate recovery of the Company's projected costs, even with accounting for embedded improvements in efficiency from 2014 to 2016.

Based on our analysis, research and industry experience, Concentric believes that EGD's overall proposed Customized IR proposal is reasonable. The proposed IR approach is the only mechanism evaluated that allows the Company the opportunity to recover its costs (including the larger than normal capital investment), while providing Enbridge with a built-in challenge for continued productivity improvement. On balance, we conclude that EGD's proposed Customized IR plan provides an appropriate safeguard for customers and the utility, and meets to Board's goals for incentive regulation while allowing the Company a reasonable opportunity to earn a fair return.

II. INTRODUCTION

A. Overview

Enbridge retained Concentric to provide analytical, research and regulatory support related to the Company's proposed 2nd Generation Incentive Regulation ("IR") Plan, which the Company is referring to as a "Customized IR" plan. Based on a combination of research, analysis and knowledge of North American incentive regulation programs, Concentric was asked to:

- Assess relevant regulatory precedents in Ontario and other North American jurisdictions pertaining to IR plans
- Research productivity factors and methods established in other jurisdictions for estimating utility productivity
- Evaluate the productivity factor approach taken by Pacific Economics Group (retained by the Board in EGD's last IR case)
- Estimate productivity factors for EGD and a study group and interpret the results and observed differences between EGD and comparators; this task included the following sub-tasks:
    - Determine the appropriate study group, data measures and timeframe for productivity analysis for EGD
    - Evaluate appropriate measures of inflation
    - Consider data limitations and issues
    - Consider costs that should be excluded because they are outside of EGD's control
    - Consider events or circumstances that should be isolated broadly or for specific companies
    - Consider any US vs. Canadian company differences
    - Evaluate the results over the historic time period in relation to Enbridge's current and anticipated operating environment
    - Compare the results to other studies
- Evaluate the appropriateness of a consumer dividend or "stretch" factor
- Benchmark Enbridge against Canadian and U.S. peers across a series of operating and cost measures.[3]

This scope evolved as Concentric's work progressed, and as Enbridge evaluated the implications for its 2nd Generation IR plan. The conclusion was ultimately reached that a traditional "I-X" framework would be challenged by Enbridge's operating circumstances over

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[3] Concentric Proposal for Consulting Services to Enbridge, December 8, 2010.

the next plan period. The Company's capital investment plans, in particular, do not fit within a "steady state" incentive regulation framework. Concentric was asked to evaluate the Company's capital spending plans, research alternative frameworks incorporating capital spending, and quantify the outcomes vis-à-vis alternative recovery mechanisms to assess the reasonableness of these approaches.

Consistent with the Ontario Energy Board's ("OEB", or the "Board") rules for expert evidence,[4] this report provides Concentric's analysis and recommendations resulting from the scope of work defined above, designed to assist the Board's deliberations on this matter. The report is divided into the following sections: the remainder of Section II provides an overview of EGD's existing IR plan; Section III summarizes EGD's proposed Customized IR framework; Section IV discusses Concentric's evaluation of EGD's productivity; Section V discusses Concentric's I Factor analysis; Section VI contains Concentric's evaluation of EGD's treatment of O&M; Section VII discusses Concentric's analysis regarding EGD's treatment of capital; Section VIII contains a discussion regarding EGD's proposed ESM; and Section IX contains an evaluation of EGD's Customized IR plan.

B. Enbridge's 2008-2012 IR Plan

Enbridge's 1st Generation IR plan (2008-2012) is the product of a settlement agreement approved by the Ontario Energy Board ("OEB" or "the Board") on February 10, 2008 in EB-2007-0615. According to the settlement agreement, Enbridge's annual distribution revenue requirement is determined by a formula that provides for increases in revenue per customer at a fixed percent[5] of annual inflation as measured by an inflation index published by Statistics Canada.[6] The approved settlement agreement also provides for recovery of specific categories of costs (Y-factor costs) on a cost of service basis and certain exogenous costs (Z-factor costs). The Distribution Revenue Requirement per Customer Formula ("Adjustment Formula") is described below:

Adjustment Formula

$$\mathbf{DRR_t = \left(\frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}}\right) * (1 + P * INF) * C_t + Y_t + Z_t}$$

Where:

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4 The OEB Rules of Practice and Procedure, Rule 13A, Expert Evidence.

5 The fixed percent ranges from 60 percent in 2008 to 45 percent in 2012.

6 The fixed percent of annual inflation is represented in the adjustment formula as: P * INF, which is comparable to the "I-X" formula frequently used. The P * INF formula represents an adjustment based on a percent of inflation, while the I-X formula represents an adjustment based on a fixed deduction from inflation.

DRR_t = The distribution revenue requirement in year t

t = The rate year

C = The average number of customers

P = The inflation coefficient

INF = The inflation index, measured as the actual year-over-year change in the annualized average of four quarters (using Q2 to Q1) of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP-IPI-FDD"), adjusted annually with no true-ups.

Y = Pass-throughs at cost of service (including DSM costs; CIS/customer care costs; upstream gas costs; upstream transportation, storage and supply mix costs; and changes in the embedded carrying cost of gas in storage and working cash related to changes in gas costs; capital expenditures related to power generation projects).

Z = Exogenous factors (meeting a materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event)).

The inflation coefficient ("P") and the implied X factor varied by year, as shown in Figure 2.

Figure 2: Inflation Coefficient over the Plan Term

Year	**Inflation Coefficient (P)**	**Implied X Factor (X) (as % GDP IPI FDD)**
2008	.60	40%
2009	.55	45%
2010	.55	45%
2011	.50	50%
2012	.45	55%

If actual ROE exceeded approved ROE by more than 100 basis points, the resultant amount was shared equally between Enbridge and its ratepayers. If actual ROE differed from approved ROE by more than 300 basis points, Enbridge was required to file an application for a review of the Adjustment Formula. The rate of return on equity ("ROE") of 8.39% that was already included in the Company's rates for 2007 was held constant over the IR period for setting rates, but earnings sharing was calculated based on the ROE Formula during the term of the IR Plan.

C. Challenges for the 2nd Generation Plan

In Concentric's view, incentive regulation programs should both serve the objectives of the regulator and stakeholders (including shareholders), while recognizing the specific operating circumstances of the utilities under the program. It is our understanding that stakeholders were generally satisfied with Enbridge's 1st Generation IR Plan, as was the Company, suggesting a balance of interests achieved in the end result.[7]

EGD and Concentric conducted a series of studies and analyses to test different structures for the Company's 2nd Generation IR Plan that would meet the following criteria specified in the Company's evidence, taken from the Board's Natural Gas Forum and the Ontario Energy Board Act:

a) Ensure appropriate reliability and quality of service (including safe operations);

b) Protect customers from unreasonable price impacts;

c) Promote energy conservation and efficiency;

d) Protect the financial viability of the distributor and allow for appropriate investments to be made; and

e) Provide a framework that incents the distributor to implement sustainable efficiency improvements.

Concentric developed an X Factor, based on a TFP study, which could be used in an I-X adjustment formula to determine an appropriate rate path for a productive utility, incenting further gains in productivity for the benefit of both customers and shareholders. Enbridge then prepared a forecast of costs, based on preliminary O&M and capital budgets. EGD also prepared a revenue forecast, based on Concentric's estimated X factor. At the conclusion of this preliminary analysis, it became evident to EGD that the 2nd Generation IR plan would have to be substantially different from the 1st Generation plan to account for Enbridge's O&M and Capital budgets for 2014 and beyond.

The single greatest challenge for Enbridge under a continued I-X framework would be accommodating the Company's capital spending plans, detailed later in this report and in the Company's B2 series of exhibits. The combination of the Greater Toronto Area ("GTA") and Ottawa Reinforcement projects and Work and Asset Management System ("WAMS") project in conjunction with elevated safety and reliability investment would lead to a substantial

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7 Based on discussions with the Company and comments made during the initial stakeholder conference to discuss the next generation IR plan on December 7, 2012.

under-recovery of costs without an adjustment to a traditional I-X IR plan. This problem challenges the implicit assumption behind a steady state I-X rate path, as has been recognized by regulators elsewhere.

The OEB's Renewed Regulatory Framework ("RRF") for Electricity (October 18, 2012) recognized that an I-X IR plan may not be appropriate for all electric distributors:

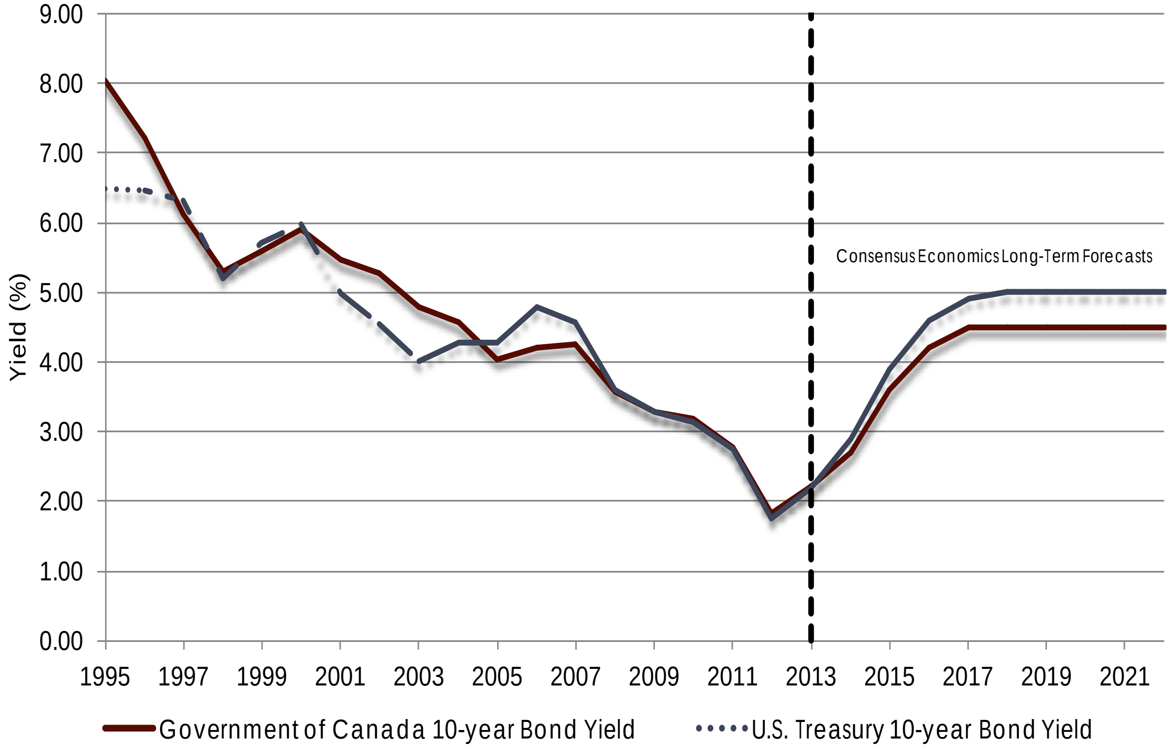
> Three alternative rate-setting methods will be available to distributors.
>
> Each distributor may select the rate-setting method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. This will provide greater flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include "lumpy" investments, and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time.[8]

Concentric's analysis of Enbridge's capital spending plans leads to the conclusion that, as envisioned for certain electric distributors, a "lumpy" and higher than normal capital spending path would not be sufficiently recovered under a traditional I-X framework. A related issue for Enbridge is a high degree of uncertainty associated with future capital spending requirements, especially beyond a three-year timeframe.

Another challenge to earning a fair return that Enbridge faces during the term of the 2nd Generation IR plan is the uncertain but likely upward path of future interest rates. This issue is not unique to Enbridge, but companies, such as Enbridge, with larger than average capital spending have greater exposure to risk from rising interest rates. The consensus view as compiled by Consensus Economics is that interest rates will rise steadily over the rate plan, but the path will depend on a host of macroeconomic and policy factors well outside the Company's control. Figure 3 depicts the consensus view.

8 Report of the Board, Renewed Regulatory Framework for Electricity, October 18, 2012, pp. 9-10.

Figure 3: 10 Year Government Bond Yield Projections



Source: Bloomberg Professional and Consensus Economics Inc.

While any utility operating under an I-X rate plan without an explicit adjustment mechanism would bear the risk of interest rate changes beyond the I-X rate path, utilities with higher-than-normal capital spending during periods of rising interest rates incur greater risk as new equity and debt financing occurs at prevailing market rates. Other risks for the Company in the 2nd Generation IR plan include uncertainty regarding system growth and its impacts on labor and other O&M costs, changes in tax rates, and the scope of certain capital projects (e.g., AMP fittings). These risks will remain with the Company under its proposed Customized IR plan.

III. PROPOSED INCENTIVE REGULATION FRAMEWORK

A. Incentive Regulation Overview

All forms of utility regulation generally include incentives, either explicitly or implicitly. Traditional cost of service ("COS") regulation includes implicit incentives to lower costs below those approved in rates to the benefit of the utility and its shareholders, and conversely costs above those in rates are absorbed by the utility to the benefit of customers. For the past several decades, regulators in North America, Europe and elsewhere have attempted to improve on these basic principles with more explicit incentive frameworks, broadly characterized as Incentive Regulation ("IR"). In doing so, regulators have sought to overcome some of the perceived shortcomings of COS regulation, such as frequent rate hearings, the inability to assess productivity and efficiency, the asymmetry of information between the utility, regulatory staff and stakeholders, and the lack of strong incentives for continuous productivity improvement.

A variety of IR frameworks have been implemented over the past two decades in the U.S. and Canada.[9] Four basic approaches have been utilized:

- Multi-year "fixed" rate plan (or "rate freeze")[10]
    - Rates are fixed over the plan period
    - Some allowances for costs beyond utility control
    - Primarily used to lock-in consumer benefit following a merger
- I-X plan[11]
    - Rate or revenue per customer escalates with inflation (I)
    - Productivity gain (X) locked in for customers
    - Some allowances for costs beyond utility control
- Targeted rate adjustment mechanisms[12]

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9 IR plans have also been implemented in the U.K. and Australia, as described in the evidence of London Economics, International.

10 See, for example, National Grid merger with Niagara Mohawk and the 10 year rate program approved for Niagara Mohawk's electric customers. NYPSC CASE 01-M-0075, December 3, 2001, and also the 5 year rate plan approved for the National Grid merger with Keyspan Corporation, NYPSC Case 06-M-0878, September 17, 2007.

11 See, for example, programs adopted in Ontario, California, Massachusetts, Maine, and Vermont.

12 See, for example, Bay State Gas Company, d/b/a Columbia Gas of Massachusetts ("CMA") where the DPU approved a cost recovery mechanism for CMA's replacement program for bare and unprotected steel infrastructure, D.P.U. 12-25 November 1, 2012; and New Jersey Board of Public Utilities Decision and

    - Tracks the costs of specific categories of O&M expenses or capital spending between rate cases
- Building Block Ratemaking[13]
    - "Building block" approach to forecast revenue
    - Productivity built into operating and capital cost projections

As a general premise, the goals of such programs have been to mitigate the aforementioned shortcomings of COS regulation, or to address specific circumstances.[14] In our experience, these programs are typically initiated with significant input from stakeholders and utilities. In recent years, we have observed a trend away from the first two types of programs toward more traditional COS approaches, targeted plans, or the building block approach. We believe this shift has been attributable to several factors: the reluctance of utilities to lock into fixed rate programs in the face of uncertain or rising costs and moderating or declining demand; the challenges associated with reliably estimating industry productivity and applying an I-X framework with many moving cost and revenue drivers; recognition by regulators and stakeholders that utilities have limited control over some cost factors, and more control over others; and the desire to target specific program areas of heightened importance (e.g., system reliability, customer satisfaction, demand side management, large capital project spending). In jurisdictions with ongoing IR frameworks, such as Ontario and California, these factors have led to revisions to previous generation plans.[15]

B. Overview of EGD's Proposed IR Framework

Enbridge is proposing a "Customized IR" plan, with features similar to those described in the OEB's Renewed Regulatory Framework ("RRF") for Electricity (October 18, 2012) and the "building blocks" approach utilized in California, the U.K. and Australia. This Customized IR plan has differences from EGD's prior plan in that it moves to an annual Revenue Cap determined from forecast costs. With this approach, both capital and O&M costs are based

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Order Approving Stipulations, 4/28/2009, for South Jersey Gas which approved a capital investment recovery tracker.

[13] See for example, programs adopted in California for SoCal Gas in proceedings AP-10-12-006), SDG&E in AP-10-12-005, and for PG&E in AP05-12-002 D07-03-044, and those adopted in the U.K. and Australia.

[14] For example, in a proceeding in which two utilities are seeking regulatory approval to merge, the regulators may require that the utility would be prohibited from filing a rate case for a specified period in order to guarantee a customer benefit from the merger.

[15] See, for example, the Ontario Energy Board, "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," October 18, 2012.

on "bottom-up" projections, aggregated to produce total revenue. Productivity is embedded in these forecasts, derived from management scrutiny of the bottom-up budgets.

Concentric has evaluated the Enbridge's proposed Customized IR plan based on our regulatory and industry research, quantitative analysis, and knowledge of other programs in North America. We have assessed Enbridge's proposed Customized IR plan from two primary perspectives:

- Consistency with Ontario and North American regulatory principles and practice;
- Quantitative assessment of Enbridge's operational efficiency and projected revenue vs. I-X rate paths.

IV. EVALUATION OF EGD'S PRODUCTIVITY

A. Introduction

EGD asked Concentric to provide a perspective on the level of Enbridge's costs and productivity relative to its industry peers. In order to provide this perspective, Concentric conducted an industry cost benchmarking study as well as an industry productivity study.

Benchmarking is a commonly employed and intuitive technique used across a wide variety of industries that compares a company's performance metrics against an industry group, which serves as the benchmark. Comparator companies are typically chosen from within the same industry, and screens are applied to narrow the field to companies with reasonably comparable operating and business conditions. For utilities, the performance metrics often include measures of cost and factors that affect cost; benchmarking metrics are typically normalized around common factors, such as number of customers, to compare the relative performance of the benchmark companies. Company size, geography, age of assets, are examples of measures that may be used in distribution utility benchmarking analyses as screens to select companies for the study, or as variables included in the analysis to explain performance differences. A Benchmarking study may be conducted for a single year or a limited number of years. Although no two companies face identical operating and business conditions, benchmarking provides a reasonable basis for company management, regulators and stakeholders to assess performance, identify best practices and to estimate performance gaps. In this case, benchmarking provides perspective on EGD's current efficiency versus its peers, which sets the state for evaluating future productivity expectations. In general, more efficient companies find incremental gains more challenging than those starting at a lower level of efficiency.

Productivity studies are used to measure a firm's effectiveness in converting its factors of production – inputs (typically measured by labour, materials and/or capital) into outputs (typically measured in physical units). Productivity analysis can be applied to single firms, whole industries or the broader economy and can be used to compare the productivity of a single firm with the productivity of the industry. The impacts of changes in the prices of inputs are controlled for to focus on measuring the productive efficiency of the economic unit, e.g. firm, industry, or economy, in converting inputs into outputs. Indexing methods are used to estimate these productivity relationships, derived from data across one or more economic units over time, and compared between different economic units. Productivity analysis has been used in several US and Canadian regulatory jurisdictions to measure utility productivity or to develop indexing mechanisms for IR plans. While the theory behind productivity is well established, model estimation is not without its challenges or controversy. Data availability is also a significant issue.

The balance of Section IV includes (a) a description of the process that Concentric used to select the companies in the industry study group; (b) a summary of Concentric's benchmarking analysis; and (c) a summary of Concentric's productivity analysis.

B. Selection of Industry Study Group

Common to both the industry benchmarking and productivity analyses performed by Concentric is the need to develop an industry study group of companies that are representative of EGD's operating circumstances. Concentric developed criteria to identify companies that are similar to EGD while allowing for a sufficient number of companies in the study group to ensure that the analyses would be robust and provide an appropriate perspective for industry comparisons. Although the same criteria were used to develop the industry study group for the benchmarking and productivity analyses, the productivity analysis industry study group has fewer companies. Some companies in the benchmarking study group were excluded from the productivity analysis due to data limitations.[16]

The companies in the industry study group were determined according to the following criteria:

- Similarity of operations to EGD - the companies in the industry study group are natural gas distribution utilities; the gas distribution company of a combination utility was included if data for natural gas distribution operations were available separately from electric operations;
- Similarity of weather conditions to EGD - the companies in the industry study group are (a) located in one of the states in the northern half of the continental U.S. and have average annual state heating degree days within +/- 45% EGD's service territory,[17] or (b) located in Canada;

16 For example, the productivity analysis study group does not include any Canadian companies because there is no centralized source that contains the detailed historical data necessary for productivity analysis, but Canadian companies were included in a limited fashion in the benchmarking analysis.

17 Based on analysis of annual HDD data from 2006 to 2011 for the U.S. states and Enbridge's service territory. Thirty-three states passed the weather screen.

- Similarity of size to EGD as measured by number of customers - the companies in the industry study group have at least 500,000 customers within a single state[18] or at least 150,000 customers within a single province;[19] and,
- Data availability - the necessary data for the companies in the industry study group are available in published or subscription service reports or databases.[20]

These criteria resulted in an Industry Study Group of 28 U.S. natural gas utilities comprised of 48 individual operating subsidiaries, and 6 Canadian natural gas utilities.[21] A subset of 25 U.S. natural gas utilities and 42 operating subsidiaries was used in the productivity analysis; Canadian gas utilities and three U.S. gas utilities were not included in the productivity analysis due to data limitations. The following table lists the companies that are included in the Industry Study Group.

18 Data for multiple operating subsidiaries of a single parent company within a state were aggregated; for example, the three operating subsidiaries of National Grid (NY) were aggregated into a single company for the purposes of our analysis.

19 The Canadian customer threshold was lowered compared to the U.S. customer threshold due to the limited universe of Canadian natural gas utilities.

20 There are a host of issues associated with building a database of this magnitude containing historical operational and cost data for many companies. Concentric has managed these issues with proxy group selection, data screening for outliers, filling in missing data where possible, and eliminating companies where data was insufficient. Please see Appendix B, Section I for more detail about data sources and database development.

21 Due to challenges associated with compiling data for Canadian utilities, only data for 2009 was obtained.

Figure 4: Industry Study Group Companies

Industry Study Group Companies		Primary State[22]/ Province	Operating Subsidiaries	
Used in Benchmarking and Productivity Analyses				
1	Ameren Corporation (Ameren IL)	IL	Central Illinois Light Company	1
			Central Illinois Public Service Company	2
			Illinois Power Company	3
2	CenterPoint Energy Resources Corp. (CenterPoint MN)	MN	CenterPoint Energy Resources Corp.	4
3	Consumers Energy Company (Consumers MI)	MI	Consumers Energy Company	5
4	Consolidated Edison, Inc. (ConED NY)	NY	Consolidated Edison Company of New York, Inc.	6
			Orange and Rockland Utilities, Inc.	7
5	Baltimore Gas and Electric Company (BG&E MD)	MD	Baltimore Gas and Electric Company	8
6	Dominion - East Ohio Gas Company (Dominion OH)	OH	East Ohio Gas Company	9
			West Ohio Gas Company	10
7	DTE Energy Company (DTE MI)	MI	Michigan Consolidated Gas Company	11
			Citizens Gas Fuel Company	12
8	Iberdrola, S.A. (Iberdrola NY)	NY	Rochester Gas and Electric Corp	13
			New York State Electric & Gas Corp	14
9	Integrys Energy Group, Inc. (Integrys IL)	IL	North Shore Gas Company	15
			Peoples Gas Light and Coke Company	16
10	Laclede Gas Company (Laclede MO)	MO	Laclede Gas Company	17
11	National Fuel Gas Distribution (National Fuel NY)	NY	National Fuel Gas Distribution Corporation	18
12	National Grid (National Grid MA)	MA	Boston Gas Company	19
			Colonial Gas Company	20
			Essex Gas Company	21
13	National Grid (National Grid NY)	NY	KeySpan Energy Delivery (formerly Brooklyn Union)	22
			KeySpan Gas East (formerly Long Island Lighting)	23
			Niagara Mohawk Power Corporation	24
14	Northern Illinois Gas Company (Nicor IL)	IL	Northern Illinois Gas Company	25
15	Columbia Gas Of Ohio (Columbia OH)	OH	Columbia Gas Of Ohio, Inc.	26

22 For a limited number of Industry Study Group Companies, data from another state were included if the "secondary state" operations were a small percent of the total company operations and if the "secondary state" data was not reported separately from the primary state data.

	Industry Study Group Companies	Primary State[22]/ Province	Operating Subsidiaries	
16	NiSource Inc. (NiSource IN)	IN	Northern Indiana Fuel & Light Company, Inc.	27
			Northern Indiana Public Service Co.	28
			Kokomo Gas And Fuel Company	29
17	Northwest Natural Gas Company (NWN OR)	OR	Northwest Natural Gas Company	30
18	Public Service Electric and Gas Company (PSE&G NJ)	NJ	Public Service Electric and Gas Company	31
19	Puget Sound Energy, Inc. (Puget WA)	WA	Puget Sound Energy, Inc.	32
20	Questar Gas Company (Questar UT)	UT	Questar Gas Company (Formerly Mountain Fuel Gas)	33
21	Southern Union Company (MGE MO)	MO	Missouri Gas Energy	34
22	Vectren Corporation (Vectren IN)	IN	Indiana Gas Company, Inc.	35
			Southern Indiana Gas and Electric Company, Inc.	36
23	Washington Gas Light Company (WGL DC,MD,VA)	DC,MD, VA	Washington Gas Light Company	37
			Shenandoah Gas Company	38
24	Wisconsin Energy Corporation (WE WI)	WI	Wisconsin Natural Gas Company	39
			Wisconsin Electric Power Company	40
			Wisconsin Gas LLC	41
25	Public Service Company of Colorado (PSCO CO)	CO	Public Service Company of Colorado	42
Used in Benchmarking Analysis, but Excluded from Productivity Analysis				
26	MidAmerican Energy Company (MidAmerican IA)	IA	MidAmerican Energy Company	43
27	Philadelphia Gas Works Company (PGW PA)	PA	Philadelphia Gas Works Company	44
28	UGI Utilities, Inc. (UGI PA)	PA	UGI Utilities, Inc.	45
			UGI Penn Natural Gas, Inc.	46
			UGI Central Penn Gas, Inc. (PA)	47
			UGI Central Penn Gas, Inc. (MD)	48
29	ATCO	AB	ATCO	49
30	FortisBC	BC	FortisBC	50
31	Gaz Metro	QC	Gaz Metro	51
32	Manitoba Hydro	MB	Manitoba Hydro	52
33	SaskEnergy Inc.	SK	SaskEnergy Inc.	53
34	Union Gas Limited	ON	Union Gas Limited	54

C. Benchmarking Analysis

Concentric conducted a cost benchmarking analysis, which measures EGD's performance against the industry study group using a series of metrics that quantify the relative efficiency of EGD in terms of both its capital investment and O&M expense profile. This benchmarking analysis is an update to a benchmarking study that was submitted in EGD's 2013 rebasing case. This update relies on the same methodology, data sources, and U.S. industry study group as the original benchmarking study, but now incorporates 2011 data. Canadian companies were included in the original benchmarking analysis for 2009; however, due to the difficulty obtaining consistent, reliable data, Canadian companies were not included in the 2011 update.

Data for EGD was provided by the Company. Data for the U.S. industry study group was primarily compiled from annual reports filed by the individual local distribution companies ("LDCs") with their state regulatory commissions ("Annual LDC Reports"). A summary of the 2011 benchmarking update is presented below; detailed results for the 2011 benchmarking update can be found in Appendix A. The original benchmarking study was submitted in EGD's rebasing case, EB-2011-0354, Exhibit A2, Tab 1, schedule 2.

To provide context and background, EGD's 2011 operational profile was compared with the peer group companies using the following metrics:

- Number of customers
- Residential customers as a percent of total customers
- System throughput
- Residential volumes as a percent of total delivery volumes
- Average natural gas use per customer
- Customers per kilometer of main
- Delivery volumes per kilometer of main.

Results for 2011 number of customers and customers per kilometer of main are provided in Figures 5 and 6. Results for all metrics are presented in Appendix A.

Figure 5: Total 2011 Natural Gas Customers
(Sales and Transportation, excludes Resale Customers)

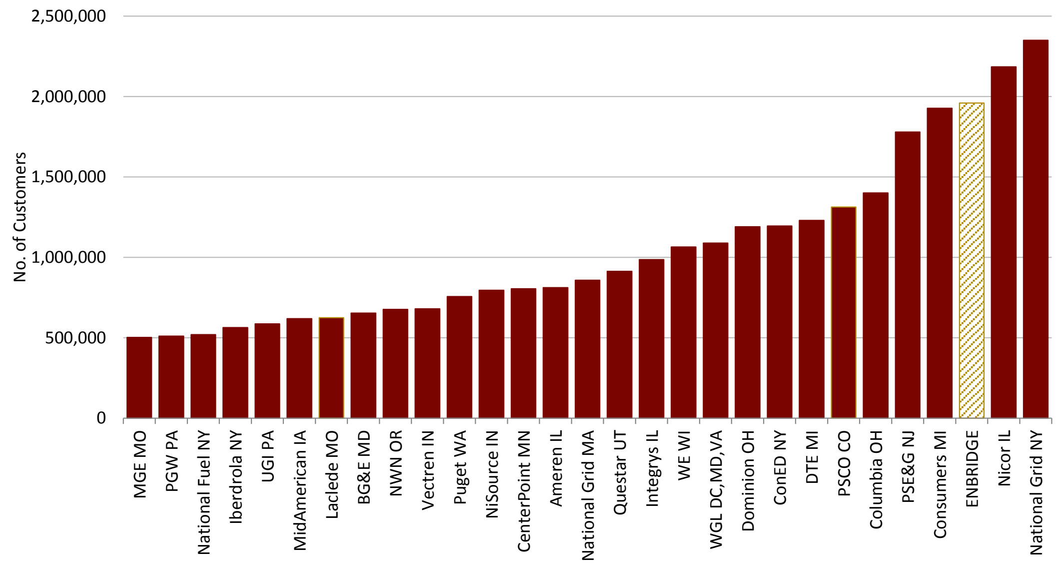
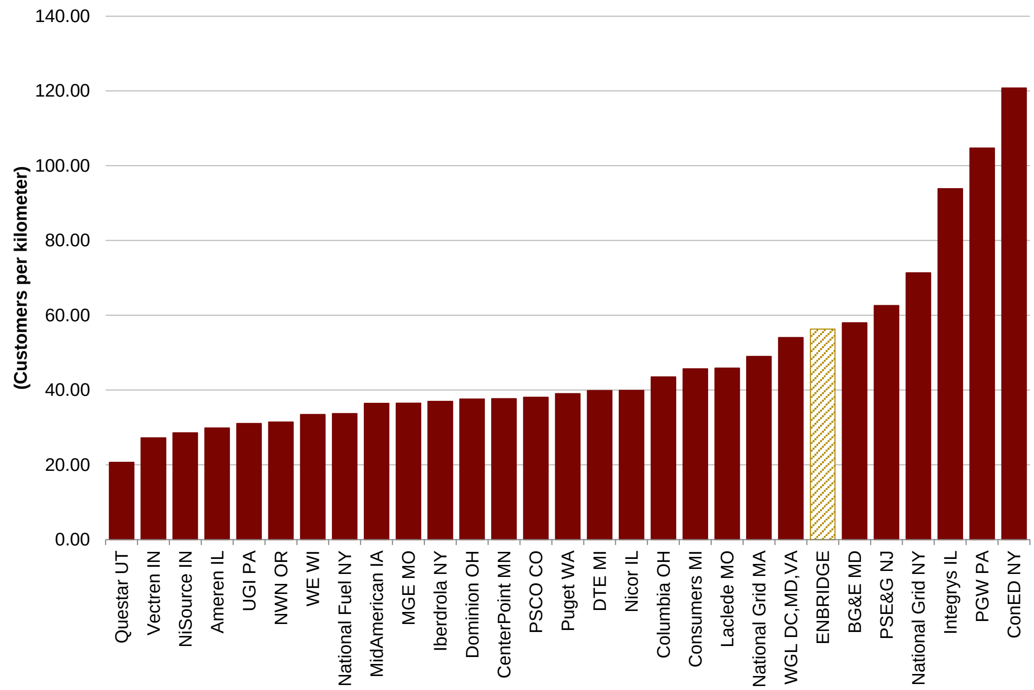


Figure 6: 2011 Natural Gas Customers per Kilometer of Distribution Main



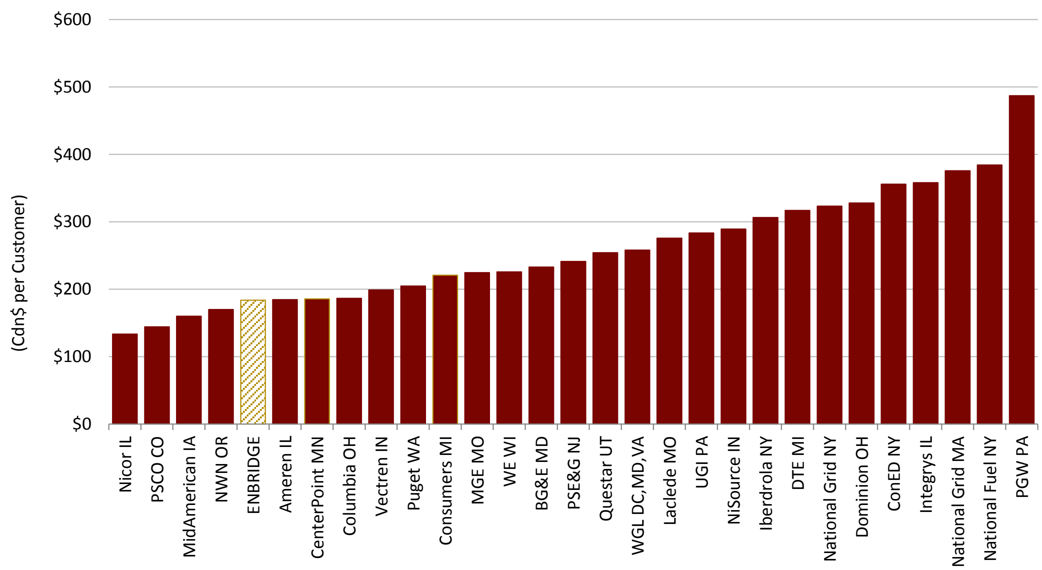
The operational profile analysis indicates that EGD is one of the largest and most dense utilities in the industry study group. EGD had the third largest customer count and volume in 2011. In addition, EGD is in the highest quartile for 2011 use per customer and density.[23]

EGD's cost performance was benchmarked against the individual companies in the industry study group for 2011 and EGD's performance trends over the 2000 to 2011 time period were compared against the industry study group average using the following metrics:

- Net plant per customer and per unit of volume
- O&M expenses per customer and per unit of volume
- Labour costs per customer and per employee (both including and excluding capitalized labour)
- Customers per employee

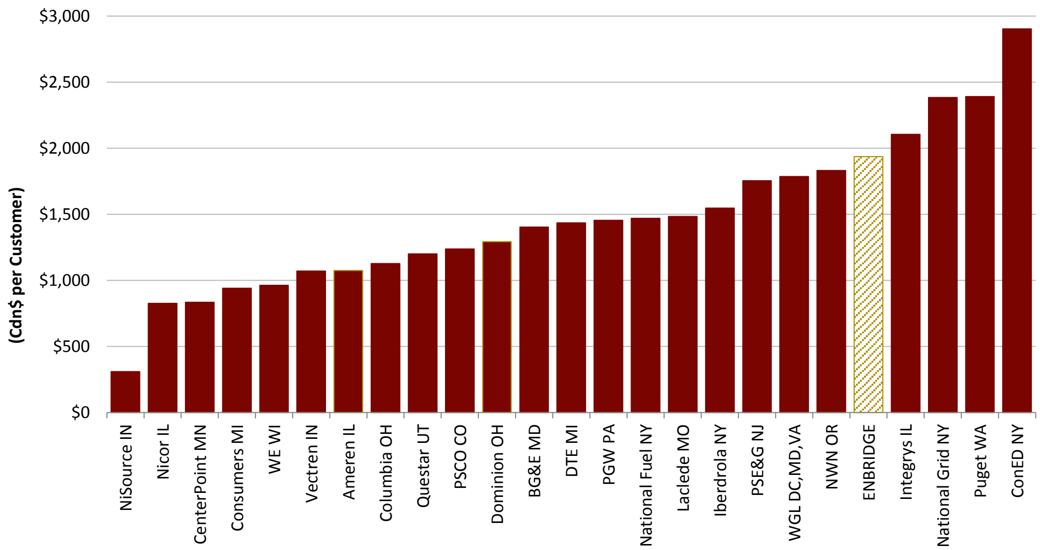
Results for 2011 O&M cost per customer and net plant per customer are presented in Figures 7 and 8. Results for all metrics are presented in Appendix A.

Figure 7: Total 2011 Gas O&M Expenses per Customer
(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)



23 Results for use per customer and density are included in Appendix A.

Figure 8: Total 2011 Net Plant per Customer
(Includes Transmission, Storage, Distribution and Allocated General Plant)[24]



EGD's 2011 O&M costs per customer, O&M costs per unit of volume, customers per employee, and labour cost per customer (excluding capitalized amounts) are within the lowest – best - quartile. In addition, EGD's 2011 net plant per volume, labour cost per customer (including capitalized amounts), and labour cost per employee are at or below the median of the industry study group. EGD's position in the top quartile of the total net plant per customer metric (EGD's net plant per customer ranking is fifth highest out of 25 companies) may appear to be inconsistent with its position in the top quartile of the customers per kilometer of distribution main (i.e. EGD's customers per kilometer ranking is seventh). However, there are other companies with similarly high plant per customer rankings and customers per kilometer of distribution rankings: ConEd, Integrys, National Grid NY and WGL. Because these LDCs serve large urban areas, it appears that the high cost of installing mains in these large urban areas may more than offset the economies of scale associated with high rankings on the customers per kilometer of main metric.

In addition to comparing EGD's 2011 cost performance to the industry study group, Concentric also compared EGD's cost trends to the industry study group average over the 2000 to 2011 time frame for the same metrics. Results for O&M cost per customer and net plant per customer are presented in the following figures. Results for all metrics are presented in Appendix A.

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[24] Some companies were excluded from the net plant metrics due to data limitations.

Figure 9: Total Gas O&M Expenses per Customer[25]

(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)

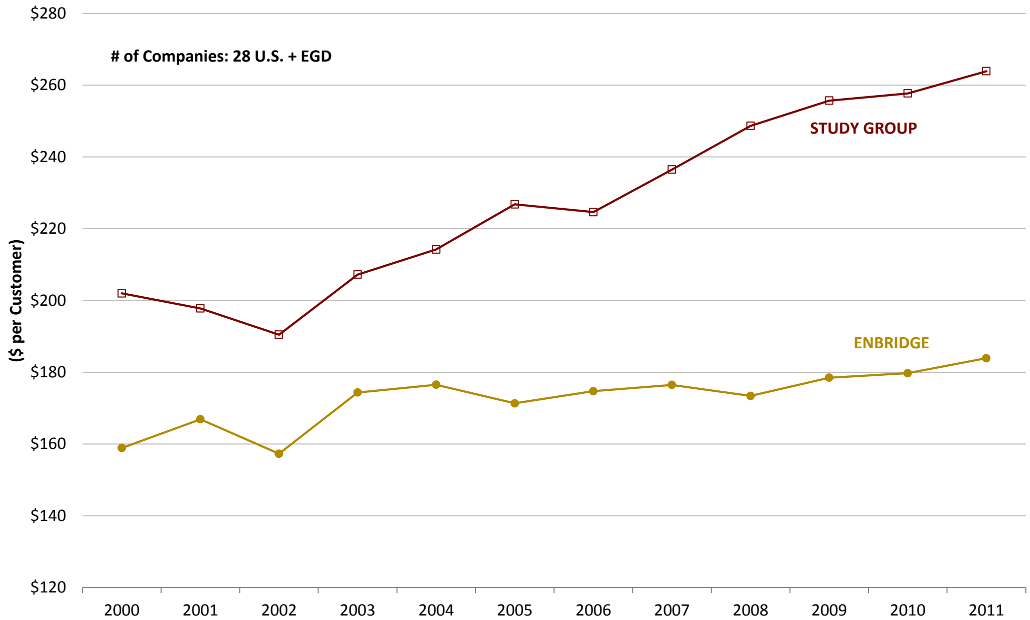


Figure 10: Total Net Plant per Customer

(Includes Transmission, Storage, Distribution, and Allocated General Plant)

25 The line charts, which compare costs over the entire 2000 to 2011 period, are expressed in own-country US and Canadian dollars for both the study group and Enbridge, which avoids issues associated with year-to-year exchange rate differences.

Regarding trends in EGD's cost performance relative to the industry study group over the 2000 to 2011 period, Enbridge has generally sustained or improved its cost position in relation to its peers, including during the most recent IR plan period. Although EGD's 2011 net plant per customer costs are above the study group average, the industry study group net plant per customer has been rising at a faster rate (3.00%) than EGD's (0.93%) over the 2000 to 2011 period.

Results from Concentric's cost benchmarking analyses indicate that EGD is among the most efficient of its industry peers, especially related to O&M and labour costs, although EGD's net plant costs per customer are high compared to the industry study group. This suggests that it may become progressively more difficult for EGD to find additional efficiencies going forward.

D. Productivity Analysis

1. Productivity Analysis Introduction

As discussed in Section IV.A, productivity analysis measures a firm's effectiveness in converting its factors of production into output, which can be measured in physical terms. Concentric conducted productivity analyses for EGD and the industry study group to allow for a comparison.

Productivity is generally specified as the difference between output growth and input growth:

Productivity Growth = Output Quantity Growth – Input Quantity Growth

A productivity index is calculated from annual changes in productivity. The productivity analysis measures total factor productivity ("TFP") if input quantity growth is measured by all inputs to the firm (i.e., capital, labour, and materials). The productivity analysis measures partial factor productivity ("PFP") if input quantity growth is measured by a subset of the inputs (e.g., labour and materials). For this study, Concentric prepared separate TFP and PFP indexes for EGD and for the industry study group. While the data sources were necessarily different for the EGD and industry study group productivity analyses, the methodology was the same.

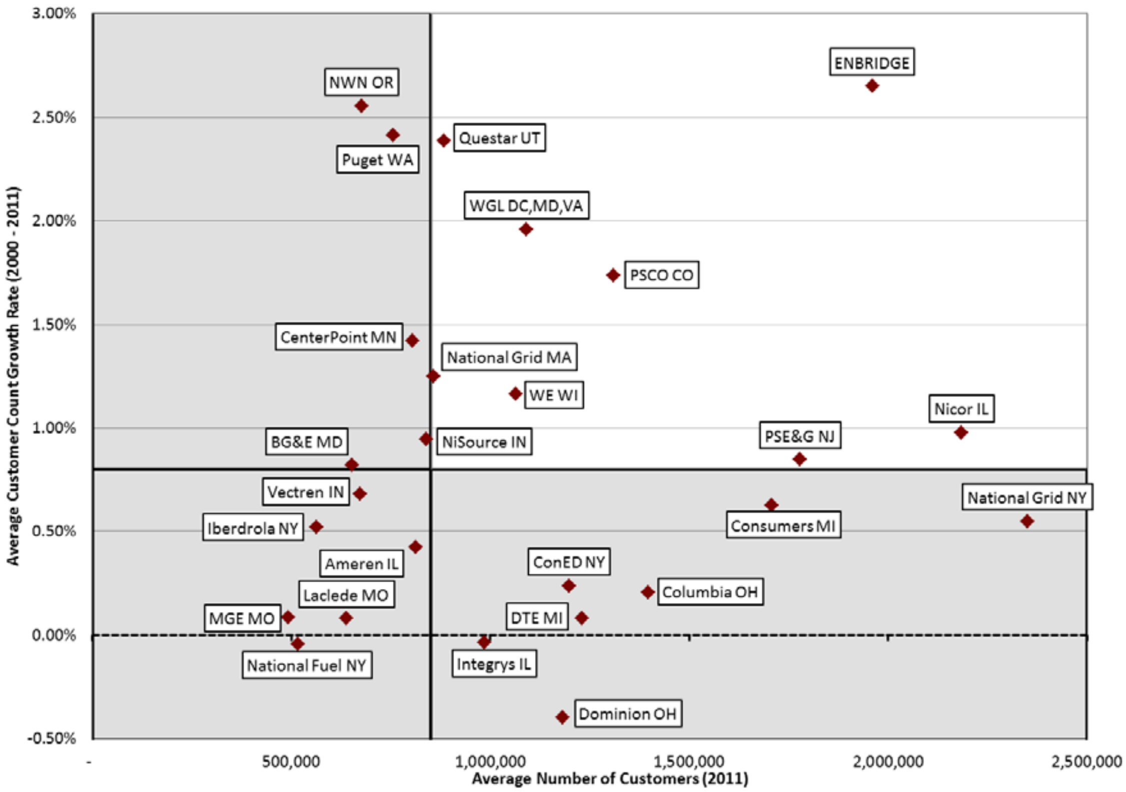
2. Determination of the Industry Study Group and Sub-Group

The industry study group used for the productivity analyses is the same as that used for the benchmarking analysis, with a few exceptions. The industry study group used in the productivity analyses consisted of 25 U.S. natural gas utilities. Canadian utilities,[26] MidAmerican, Philadelphia Gas Works and UGI were not included in the productivity analyses because the required data was not available.

In order for the productivity analysis to reasonably compare the target company – EGD – with other companies, the industry sample group should be similar to the target company as measured by factors that affect gas distribution cost structures. Because EGD is larger and has experienced higher customer growth rates in recent years than many of the 25 companies in the industry study group, Concentric developed a sub-group for the productivity analyses by applying more restrictive size and customer growth criteria to the 25 industry study group companies. Figure 11 provides a graphical representation of the more restrictive criteria. Each of the 25 industry study group companies plus EGD are represented on the scatter plot; the size of company, as measured by 2011 customer count, is reflected on the (horizontal) X-axis, and the 2000 to 2011 customer growth rate for each company is reflected on the (vertical) Y-axis. As shown in Figure 11, the customer counts for the 25 companies plus EGD range from approximately 500,000 to over 2.3 million. Only two companies in the industry study group have more customers than EGD's 1.9 million customers. As also shown in Figure 11, the 2000 to 2011 customer growth rates for the 25 companies plus EGD range from -0.4% to over 2.6%. EGD's customer growth rate, 2.6%, is higher than all other companies in the industry study group.

[26] Except EGD.

Figure 11 Customer Count and Customer Growth Rates



Based on these considerations, Concentric determined that a sub-group of companies with at least 850,000 customers in 2011, and at least 0.8% customer growth over 2000 to 2011 would result in a sub-group that is more representative of EGD and of sufficient size to provide meaningful results. The sub-group, which is represented in the top right-hand quadrant in the scatter plot (shaded white), consists of seven companies: Northern Illinois Gas Company, Public Service Electric and Gas Company, Questar Gas Company, Public Service Company of Colorado, National Grid (MA), Washington Gas Light Company, and WE Energies. Altogether, Concentric conducted TFP and PFP analyses for (a) the seven company sub-group, (b) the 25 company industry study group, and (c) EGD.

Concentric's company-specific TFP and PFP indexes for EGD and for each of the companies in the industry study group (and the seven company sub-group) are based on company-specific Input Indexes and Output Indexes. Concentric developed TFP and PFP indexes for the industry study group and the seven company sub-group by weighting the individual company Input and Output indexes.[27] The TFP and PFP results are provided in the following sections; details of the TFP and PFP data sources and methodology are provided in Appendix B.

3. *TFP Results*

The TFP growth rates, representing the difference between the output quantity and TFP input quantity[28] index growth rates, are shown in the following figures.

Figure 12: TFP Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[29] (2000-2011)

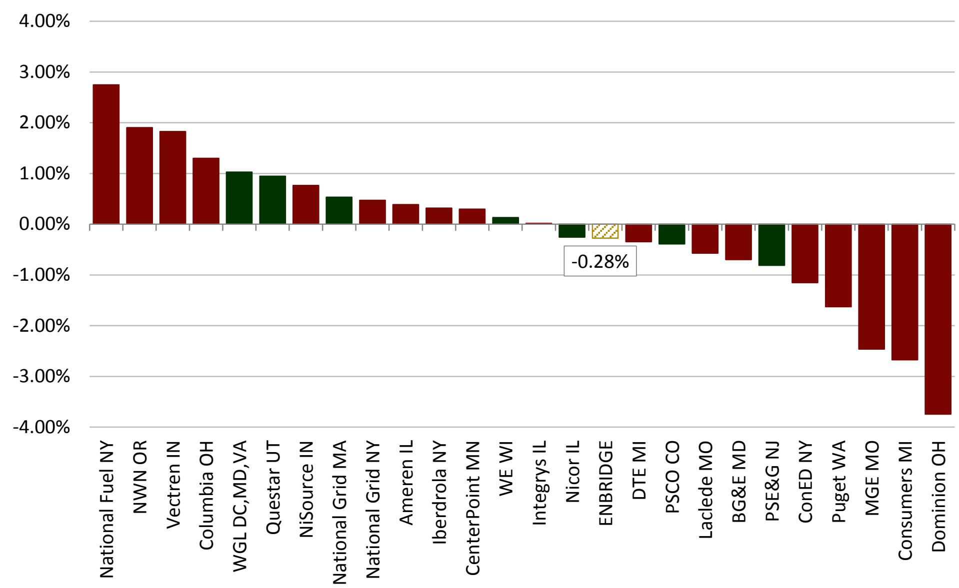


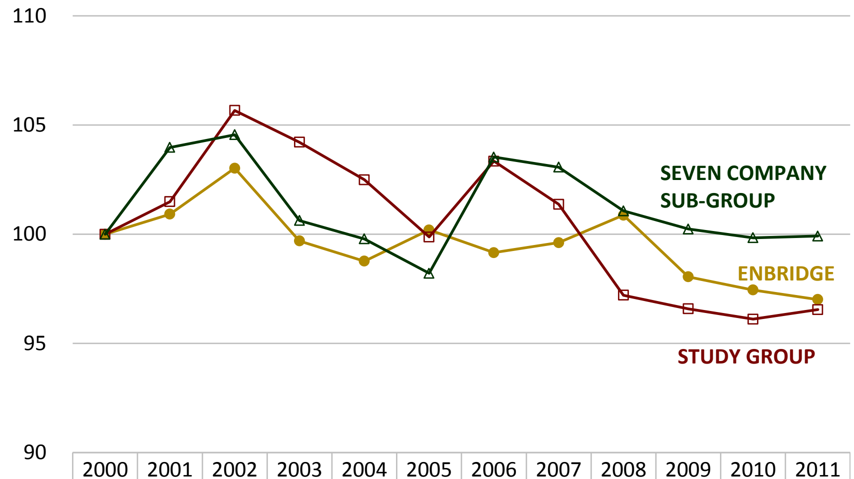
Figure 12 indicates that the TFP index growth rate for many companies has been negative over the 2000 to 2011 period. Negative TFP growth indicates that TFP input quantities (i.e., the combination of capital, materials and labour) are growing faster than output quantities (i.e., number of customers).

27 Company-specific input indexes were weighted by input costs; company-specific output indexes were weighted by total distribution revenue.

28 TFP Input Quantities are represented by capital, labour and materials.

29 The companies in the seven company sub-group are indicated by green shading.

Figure 13: TFP Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	101	103	100	99	100	99	100	101	98	97	97
Study Group	100	101	106	104	102	100	103	101	97	97	96	97
7 Co. Sub-Group	100	104	105	101	100	98	104	103	101	100	100	100

Figure 14: TFP Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		TFP Growth Rate	TFP Index	TFP Growth Rate	TFP Index	TFP Growth Rate	TFP Index
Pre-IR	2000		100.00		100.00		100.00
	2001	1.48%	101.49	3.90%	103.97	0.91%	100.92
	2002	4.03%	105.67	0.56%	104.56	2.06%	103.02
	2003	-1.39%	104.21	-3.83%	100.63	-3.29%	99.69
	2004	-1.66%	102.49	-0.84%	99.78	-0.93%	98.77
	2005	-2.59%	99.87	-1.59%	98.21	1.44%	100.20
	2006	3.42%	103.34	5.27%	103.53	-1.04%	99.16
	2007	-1.93%	101.37	-0.45%	103.07	0.46%	99.61
During IR	2008	-4.19%	97.21	-1.96%	101.07	1.25%	100.87
	2009	-0.64%	96.58	-0.82%	100.24	-2.84%	98.05
	2010	-0.49%	96.11	-0.40%	99.84	-0.62%	97.44
	2011	0.46%	96.55	0.08%	99.92	-0.45%	97.01
Average Annual Growth Rates							
Whole Period	2000-2011	-0.32%		-0.01%		-0.28%	
Pre-IR	2000-2007	0.19%		0.43%		-0.06%	
During IR	2007-2011	-1.22%		-0.78%		-0.66%	

Over the entire 2000 to 2011 study period, the seven company sub-group TFP growth rate, -0.01%, is higher than the 25 company industry study group TFP growth rate, -0.32%, which indicates greater TFP growth for the seven company sub-group. For the study period of 2000 to 2011, EGD's TFP growth rate, -0.28%, is very similar to the industry study group average of -0.32%, but lower than the seven company sub-group average of -0.01%. Although the industry group that Pacific Economics Group ("PEG") used in recent TFP analyses for Ontario electric distributors was different from the industry study group in Concentric's TFP analysis, PEG's TFP results using indexing methods (-0.05% and 0.1%) and using econometric methods (-0.03% and 0.07%) are very similar to Concentric's seven company sub-group TFP result (-0.01%).[30,31]

Likely as a result of the economic recession that started in 2008 and ongoing DSM/energy efficiency programs, TFP growth rates from 2007 to 2011 were less than TFP growth rates from 2000 to 2007 for Concentric's three TFP indexes – the industry study group, seven company sub-group and EGD. However, the decline in EGD's TFP growth rate from 2000 to 2007 compared to 2007 to 2011 (-0.60%[32]) was less than the industry group's TFP growth rate decline (-1.41%,[33]) and also less than the seven company sub-group's TFP growth rate decline (-1.21%.[34]) As a result, Enbridge outperformed both industry groups over the most recent period. EGD's relative productivity performance may be explained by (a) the incentives for improvements in efficiency that resulted from EGD's 1st Generation IR plan, and (b) EGD's relatively high output (i.e., customer) growth rate from 2007 to 2011, compared to industry study group or seven company sub-group companies.

4. PFP Results

The PFP input quantity index is an aggregation of labour and materials quantity sub-indexes; the PFP input quantity index differs from the TFP input quantity index in that the PFP input quantity index excludes capital quantities. Concentric measured output growth for both the PFP and TFP output quantity index as the annual growth in customers. The PFP index growth rates, representing the difference between the output quantity and PFP input quantity index growth rates, are shown in Figures 15, 16 and 17.

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30 Pacific Economics Group Research, LLC, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board," May 3, 2013, subsequently revised on May 31, 2013.

31 PEG's TFP results would have been -1.24% (May 3, 2013 Report) or -1.10% (May 31, 2013 revision) if they had included Toronto Hydro and Hydro One, which they excluded from their analyses.

32 EGD's Change in TFP growth = 2007 to 2011 TFP growth – 2000 to 2007 TFP growth = (-0.66%) – (-0.06%) = -0.60%

33 The Industry Study Group's Change in TFP growth = 2007 to 2011 TFP growth – 2000 to 2007 TFP growth = (-1.22%) - (0.19%) = -1.41%

34 The Seven Company Sub-Group's Change in TFP growth = 2007 to 2011 TFP growth – 2000 to 2007 TFP growth = (-0.78%) - (0.43%) = -1.21%

Figure 15: PFP Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[35] (2000-2011)

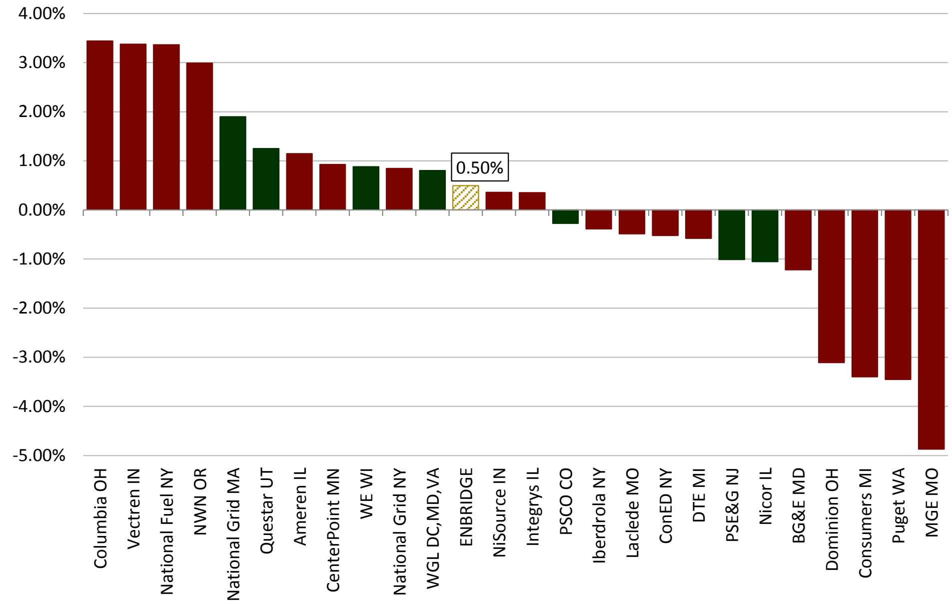
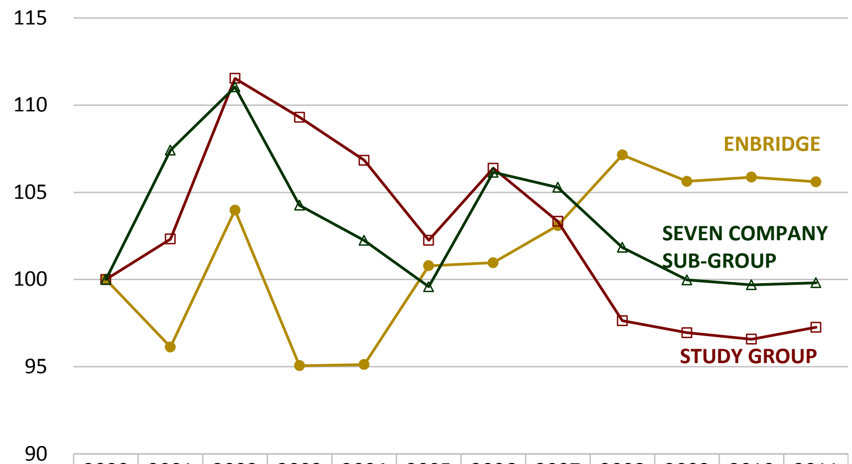


Figure 15 illustrates that many companies experienced negative PFP growth over the 2000 to 2011 period; negative PFP growth indicates that PFP input quantities (i.e., the combination of materials and labour) are growing faster than output quantities (i.e., number of customers).

35 The companies in the seven company sub-group are indicated by green shading.

Figure 16: PFP Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	96	104	95	95	101	101	103	107	106	106	106
Study Group	100	102	112	109	107	102	106	103	98	97	97	97
7 Co. Sub-Group	100	107	111	104	102	100	106	105	102	100	100	100

Figure 17: PFP Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		PFP Growth Rate	PFP Index	PFP Growth Rate	PFP Index	PFP Growth Rate	PFP Index
Pre-IR	2000		100.00		100.00		100.00
	2001	2.30%	102.32	7.16%	107.42	-3.94%	96.13
	2002	8.62%	111.54	3.32%	111.04	7.85%	103.98
	2003	-2.02%	109.30	-6.31%	104.25	-8.97%	95.06
	2004	-2.28%	106.84	-1.95%	102.24	0.07%	95.12
	2005	-4.39%	102.25	-2.63%	99.58	5.79%	100.79
	2006	3.96%	106.38	6.38%	106.15	0.17%	100.96
	2007	-2.90%	103.34	-0.82%	105.29	2.09%	103.10
During IR	2008	-5.67%	97.64	-3.33%	101.84	3.85%	107.14
	2009	-0.71%	96.95	-1.85%	99.98	-1.42%	105.63
	2010	-0.38%	96.58	-0.28%	99.70	0.23%	105.87
	2011	0.70%	97.26	0.12%	99.81	-0.25%	105.60
Average Annual Growth Rates							
Whole Period	2000-2011	-0.25%		-0.02%		0.50%	
Pre-IR	2000-2007	0.47%		0.74%		0.44%	
During IR	2007-2011	-1.52%		-1.33%		0.60%	

Over the entire 2000 to 2011 study period, the seven company sub-group PFP growth rate, -0.02%, is higher than the 25 company industry study group PFP growth rate, -0.25%, which indicates greater PFP growth for the seven company sub-group. For the study period of 2000 to 2011, EGD's PFP rate, 0.50%, is significantly higher than the industry study group average, -0.25%, and the seven company sub-group average of -0.02%, indicating that Enbridge was more productive than both groups. PFP growth rates from 2007 to 2011 were less than PFP growth rates from 2000 to 2007 for both the industry study group and the seven company sub-group; the industry study group's PFP declined by -1.98%[36] and the seven company sub-group's PFP declined by -2.07%[37]. However EGD's PFP improved by 0.16%[38] between 2000 to 2007 and 2007 to 2011. EGD's PFP improvement between 2000 to 2007 and 2007 to 2011 may again be attributable to (a) the incentives for improvements in efficiency that resulted from EGD's 1st Generation IR, and (b) EGD's relatively high output (i.e., customer) growth rate from 2007 to 2011, compared to industry study group or seven company sub-group companies.

5. X Factor

The creation of incentives for greater productivity lies at the heart of IR plans. In an I-X framework, X is an explicit measure of productivity, typically measured through analysis of historical industry performance. In a "building block" approach, X may be derived from the total revenue path, or used to evaluate the productivity embedded in the projected revenue path. The analysis of productivity and calculation of X provided by Concentric serves two roles in EGD's proposed plan: (1) the TFP industry X was used to evaluate the sufficiency of an I-X rate path for EGD's Allowed Revenue amounts; and (2) the PFP industry X was used to evaluate the productivity embedded in EGD's O&M budgets for the 2014 to 2016 period. In sum, EGD requested that Concentric develop an X Factor, and forecasted I Factors (discussed in Section V) to evaluate the reasonableness of the Allowed Revenue amounts that are included in EGD's Customized IR plan.

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36 The Industry Study Group's Change in TFP growth = TFP growth during IR – TFP growth prior to IR period = (-1.52%) - (0.47%) = -1.98%

37 The Seven Company Sub-Group's Change in TFP growth = TFP growth during IR – TFP growth prior to IR period = (-1.33%) - (0.74%) = -2.07%

38 EGD's Change in TFP growth = TFP growth during IR – TFP growth prior to IR period = (0.60%) – (0.44%) = 0.16%

To develop X factors based on the TFP and PFP analyses discussed above, Concentric considered: (1) whether EGD, the industry study group, or the seven company sub-group productivity results should be used, and (2) the appropriate time frame to include.

It is appropriate to evaluate EGD based on the industry productivity standard. Looking to a peer group sample of companies provides an objective measure of similarly situated companies, and avoids over-reliance on individual company data that may be skewed by unique operating circumstances, accounting practices, or regulatory treatment, provided that the study group is sufficiently representative. Regarding whether the 25 company industry study group or the seven company sub-group should be used, Concentric used the seven company sub-group TFP and PFP results to develop an X Factor because, for all three time periods, the seven company sub-group results were higher than the 25 company industry study group, and therefore represented a more aggressive productivity target.

In choosing the years on which to base the productivity analysis to be used to estimate the X factor, it is necessary to balance three factors: (1) using a sufficiently long period to smooth out the effects of year-to year variations; (2) using a sufficiently short, and recent period to reflect expected productivity growth in the near term; (3) data availability. Ideally, productivity analyses should include the most recent 10-15 years of data.

As demonstrated in Figures 14 and 17, the TFP and PFP Index growth rates vary from year to year and over time. For example, the average TFP Index for the seven company sub-group over 2000 to 2011 is -0.01%, but would be -0.78% if computed over the more recent 2007 to 2011 period. The average PFP Index for the seven company sub-group over 2000 to 2011 is -0.02%, but would be -1.33% if computed over the more recent 2007 to 2011 period. The recent decline in productivity has been the result of an increase in the input index, accompanied by slowing increases in the output index over the same time period. Experts in the application of utility IR plans offer "When no major structural changes are anticipated in the economy, historic data on productivity and input price growth rates often provide reasonable estimates of corresponding future growth rates."[39] Using the 2000 to 2011 period for determination of the TFP and PFP on a going forward basis represents a built in challenge requiring reversal of recent slowing output growth and rising input growth.

Concentric recommends using TFP and PFP X Factors of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan, based on the 2000

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[39] Bernstein and Sappington, 'How to Determine the X in RPI – X regulation: A User's Guide", *Telecommunications Policy*, 24, 2000, p. 65.

to 2011 TFP results for the seven company sub-group of -0.01% and the 2000 to 2011 PFP results for the seven company sub-group of -0.02%. Concentric's recommendation of an X Factor of 0% is identical to PEG's recommended X Factor of 0% for the Ontario electric distributors contained in their May 3, 2013 report to the Board, and very similar to PEG's recommended X Factor of 0.1% contained in their May 31, 2013 revision.[40]

Concentric's recommended TFP-based X Factor of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan can be viewed as presenting a built-in productivity challenge to EGD of 30-75 basis points. As discussed previously, the 25 company industry study group TFP results would suggest an X Factor of -0.32%; however Concentric is recommending a more aggressive X Factor of 0% based on the seven company sub-group TFP results, implying a productivity challenge of approximately 30 basis points for EGD. In addition, Concentric is using the entire 2000 to 2011 time frame from the seven company sub-group TFP to derive our recommended X Factor; if Concentric had used the more recent 2007 to 2011 time period, the X Factor recommendation could have been lower by over 75 basis points. Similarly, Concentric's recommended PFP-based X Factor of 0% can be viewed as presenting a built in productivity challenge to EGD of 20-130 basis points. Concentric believes that the X factor recommendation of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan provides EGD with an aggressive productivity challenge.

A stretch factor is an optional adder to the X factor, which increases the offset to the I Factor and therefore decreases revenue per customer growth. The stretch factor acts as a customer benefit factor in that it assigns to customers a minimum level of the benefits of expected productivity growth beyond that captured in the X factor; rates are reduced to account for the stretch factor, regardless of whether the utility achieves that incremental productivity growth. In Concentric's view, there are generally two situations in which a stretch factor may be appropriate: (a) when a utility is transitioning from cost of service regulation to performance or incentive based regulation, and (b) to reflect that the utility is less efficient than its peers.[41] Neither of these situations applies to EGD. EGD has been under some form

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40 Pacific Economics Group Research, LLC, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board," May 3, 2013, subsequently revised on May 31, 2013.

41 Both of these situations are consistent with views on stretch factors contained in PEG's May 3, 2013 report and May 31, 2013 revision to the Board. "PEG also recommends that the stretch factor for the largest group be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time" (p. 90); "Larger stretch factors are assigned for relatively less

of incentive regulation for a number of years, and has been operating under its 1st Generation IR plan since 2008. In addition, based on the results of cost benchmarking analyses conducted by Concentric, EGD is among the most efficient of its U.S. and Canadian peers.

While the Ontario electric utilities have performance-based stretch factors, the justification for the stretch factors was in part due to preference of a stretch factor over an earnings sharing mechanism. In the 3rd Generation IR for electric distributors, the Board observed that "[stretch factors] are somewhat analogous to earnings sharing mechanisms."[42] However, because EGD is proposing an earnings sharing mechanism, if EGD is able to produce additional productivity growth, the additional earnings beyond the dead band will be shared with customers. Therefore, a stretch factor is not necessary because EGD's proposed ESM achieves customer benefits that might otherwise be achieved with a stretch factor, with additional opportunity for greater customer benefits.

Therefore, Concentric determined that an explicit stretch factor is not necessary because (a) EGD has ample experience under an IR regime – EGD is not embarking on a 1st Generation IR Plan; (b) EGD is a relatively efficient utility, (c) EGD's proposed ESM provides opportunities for customer benefits in place of a stretch factor, and (d) Concentric's X Factor recommendation can be viewed as having a built-in productivity challenge.

E. Conclusions

Concentric's benchmarking analysis demonstrates that EGD is currently an efficient utility and that EGD has continued to improve its performance relative to its industry peers, especially related to O&M costs. Furthermore, Concentric's productivity analysis demonstrates that EGD improved its productivity as measured by both TFP and PFP during the 1st Generation IR plan (2007 – 2011) compared to the pre-IR plan period (2000 - 2007) relative to performance of both the 25 company industry study group and the seven company sub-group during those same periods, which indicates that EGD made productivity improvements during the 1st Generation IR plan. This suggests that the potential productivity improvements that are often available at the onset of IR may have less potential in the 2nd Generation IR. While it is important that EGD continue to look for additional efficiency and productivity improvement opportunities, they may be more difficult for EGD

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efficient distributors since they are deemed to have greater potential to achieve incremental productivity gains." (p. 89); and PEG assigned a stretch factor of 0 to the most efficient group. (p. 90)

42 "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, EB-2007-0673, September 17, 2008, p. 19.

to find. Based on Concentric's TFP and PFP analyses, Concentric recommends an X Factor of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan.

V. MEASURE OF INFLATION

A. Introduction

In a stable, competitive environment, economic theory suggests that a firm's costs will increase by price inflation minus productivity improvements; this principle is the basis for I-X incentive ratemaking formulas. The purpose of the I Factor in an I-X formula is to account for inflation in input prices, whereas the X Factor accounts for productivity. Concentric was asked by EGD to provide a recommendation for an appropriate I Factor to be used with a productivity factor to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan. To develop our recommendations, Concentric researched the use of I Factors in I-X incentive ratemaking formulas in Ontario as well as in other jurisdictions, and conducted related analysis.

Utilities employ labour, materials and capital as inputs in their operations, and the associated labour, materials and capital prices are generally considered to be outside the control of the utility. Concentric's I Factor is therefore designed to accommodate increases in these input prices. The I Factor used for the purposes of this evaluation should generally meet the following criteria:

- Published by a reliable outside source (e.g., a government agency or reputable third party)
- Available on a timely basis
- Relatively uninfluenced by the performance of the utility to which it is being applied
- Reflective of the input prices facing the industry to which it is being applied (in this case gas distribution)

In addition, the I Factor should be relatively straightforward to calculate.

There are two common approaches to developing the I Factor used in I-X type formulas: (1) using a single macroeconomic index; or (2) using a composite I Factor. The benefit of a macroeconomic I Factor in an I-X formula, such as GDP-IPI-FDD[43] that was used in EGD's 1st Generation IR plan, is that it is straightforward to implement.[44] However, using a macroeconomic index for the I Factor presents a number of challenges, including requiring implicit adjustments to the X Factor. The macroeconomic index chosen is typically a

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43 GDP-IPI-FDD: Gross Domestic Product Implicit Price Index Final Domestic Demand

44 A macroeconomic I Factor would be determined by calculating the annual change in the published macroeconomic index.

measure of output prices in the overall economy (e.g., a measure of GDP); however, the goal is to identify an input price inflation index for the gas distribution industry. Therefore, it is necessary to adjust the macroeconomic index (a) for the difference between the input prices experienced by the industry and the input prices in the overall economy, and (b) to account for the difference in productivity between the economy and the industry.[45] These implicit X Factor adjustments require additional data, and details associated with the calculations can be subject to debate. Also, the X Factor adjustments are typically fixed at a point in time, so any changes in the relationship between industry and economy input prices, or the change in productivity between the industry and economy will not be captured. In addition, to the extent that the macroeconomic index does not accurately reflect the utility's input prices (even with the implicit adjustments), it could lead to unjustified swings in earnings or customer costs.

Some jurisdictions have chosen to adopt a composite I Factor in their I-X formulas that more directly reflects input prices faced by utilities. A composite I Factor is calculated as a weighted average of separate indices that track changes in items such as labour prices, materials prices, and capital prices faced by the utility. A composite I Factor is a more direct measure of utility input prices, so it eliminates the need to make implicit adjustments to the X Factor to account for the difference between input prices and productivity of the industry and the economy. The challenges of a composite I Factor include choosing the specific indices to represent the separate price components, and identifying the weights to apply to each index to develop the composite I Factor. In addition, the methodology chosen to develop the composite I Factor can be relatively simple, or it can be very complex, depending on the approach taken.

B. I Factor Recommendation

Concentric considered the benefits of the continued use of the existing GDP-IPI-FDD inflator versus a composite factor to evaluate the Allowed Revenue amounts included in EGD's Customized IR plan. In doing so, Concentric researched a broad array of potential indices and examined their sources, components and availability. Based on the availability of price indexes that more specifically reflect labour and capital costs, and the historical evidence that illustrates the potential for these cost indices to diverge from the general rate of inflation, we believe it is appropriate to utilize those more specific indices to reflect price

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45 This second adjustment is necessary because the macroeconomic index is a measure of output prices, which includes the productivity of the economy in converting inputs to outputs.

changes in those specific inputs.[46] In addition, the implicit adjustments to the X Factor that are necessary to account for the differences in productivity and input prices embedded in the generic macroeconomic index require additional data, can be imprecise, and the appropriate methodology can be controversial. Concentric therefore believes it is preferable to use a composite I Factor that explicitly tracks changes in input prices and eliminates the need for X Factor adjustments. On balance, we recommend a composite I Factor comprised of a weighted average of the following indices: (1) Ontario Average Hourly Wages (all employees) for labour-related prices,[47] (2) Canada GDP-IPI-FDD for materials prices,[48] and (3) Canada implicit price index for net gas distribution plant for capital prices as shown in the following graph.[49]

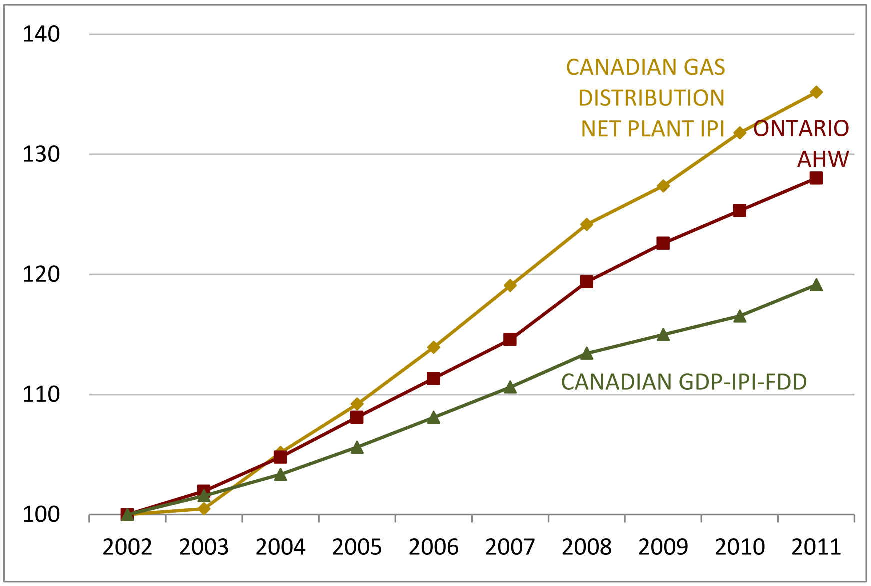
[46] We have not identified a superior alternative to the GDP-IPI-FDD inflator for materials, so we continue to use that index.

[47] Source: Statistics Canada. Table 282-0069 - Labour force survey estimates (LFS), Ontario, All Employees, wages of employees by type of work, National Occupational Classification for Statistics (NOC-S), sex and age group, unadjusted for seasonality; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on March 1, 2013.

[48] Source: Statistics Canada, Table 380-0066, Gross domestic product (GDP) indexes, Canada, Implicit price indexes, Final domestic demand, quarterly (2007=100) available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on April 1, 2013.

[49] Source: Statistics Canada, Table 031-0002, Flows and stocks of fixed non-residential capital, by North American Industry Classification System (NAICS) and asset, annual (dollars x 1,000,000); Canada; Current Prices and 2007 Constant Prices; Natural Gas Distribution; Geometric end-year net stock; Total assets; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on March 1, 2013.

Figure 18: Graph of I Factor Price Sub-Indices (Indexed to 2002)



The historical data for these three sub-indices illustrates that input prices for capital (Canadian Gas Distribution Net Plant IPI) and labour (Ontario AHW) have escalated more rapidly than overall inflation (Canadian GDP-IPI-FDD), which indicates that Canadian GDP-IPI-FDD is not an ideal representation of labour or capital input prices. This is not surprising given the rising costs of steel and plastic over this period, and continued pressure on labour costs experienced in Ontario and elsewhere.

In addition, the proposed indices meet all the I Factor criteria listed in Section V.A above. First, the three indices are publicly available from Statistics Canada. The Ontario Average Hourly Wages is published monthly, the Canadian GDP-IPI-FDD is published quarterly, and the Net Plant implicit price index data is published annually, so they are available on a timely basis. As shown in Figure 18, all indices are relatively stable. While EGD is a large utility in Ontario, its employment levels do not significantly affect the Ontario Average Hourly Wage index for all employees. Conversely, given that EGD is competing against other Ontario businesses in the labour market, the Ontario Average Hourly Wage index for all employees is a good indicator of the labour price pressures faced by EGD. EGD is certainly not large enough to affect the measurement of Canadian GDP-IPI-FDD; likewise, Canadian GDP-IPI-FDD remains a reasonable proxy for the non-labour input price pressures faced by EGD. Lastly, due to the difficulty in obtaining a capital price index for Ontario natural gas utilities, Concentric determined that the net gas distribution plant index for Canada is the most appropriate indicator of the capital cost pressures faced by EGD. Figure

21 contains graphs of these three price indices, and Concentric's recommended composite indices for both two and three component inputs ("sub-indices"), indexed to 2002.

To develop a comprehensive TFP I Factor applicable to all three input components (i.e., labour, capital and materials), Concentric weighted the labour price index by 19%, the materials price index by 33%, and the capital price index by 48%. For a partial PFP I Factor applicable to labour and materials, Concentric weighted the labour price index by 38% and the materials price index by 62%. The weights are based on the 2009 to 2011 average cost weights for the input sub-indexes from the seven company sub-group TFP and PFP analyses, as shown in Figures 19 and 20. Using industry cost weights rather than EGD's cost weights, appropriately eliminates EGD's ability to affect the weighting of the sub-indices for the I Factor.

Figure 19: 2009-2011 Average Input Sub-Index Cost Weights

Seven Company Sub-Group TFP

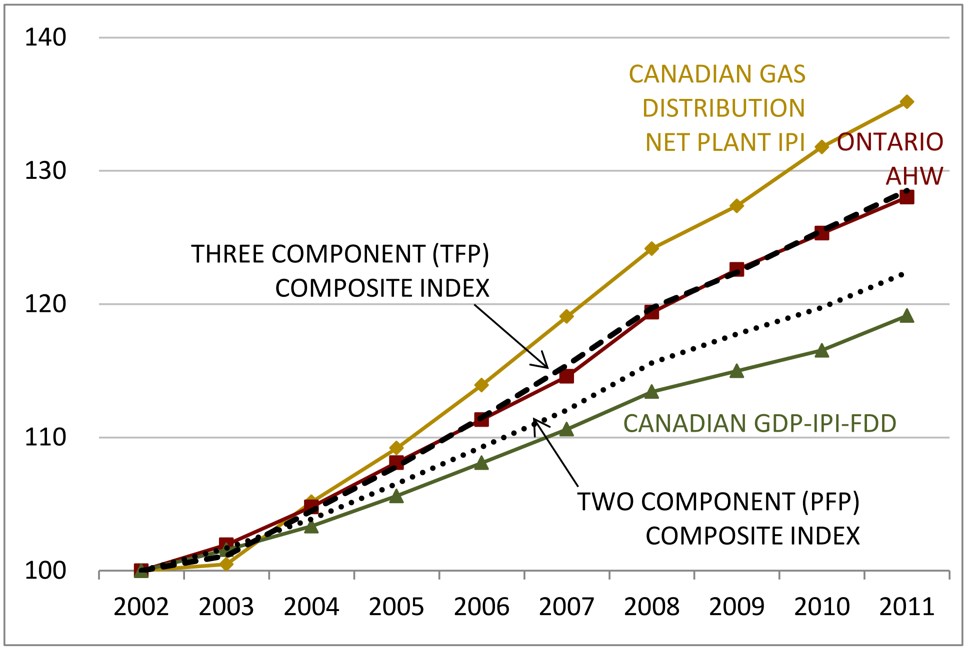
	Capital	Labour	Materials
2009	51%	18%	31%
2010	51%	18%	30%
2011	43%	21%	37%
2009-2011 Average	**48%**	**19%**	**33%**

Figure 20: 2009-2011 Average Input Sub-Index Cost Weights

Seven Company Sub-Group PFP

	Labour	Materials
2009	38%	62%
2010	39%	61%
2011	37%	63%
2009-2011 Average	**38%**	**62%**

Figure 21: Graph of I Factor Composite Price Indices (Indexed to 2002)



While the specific indices chosen and the specific calculations differ, Concentric's approach to developing a composite I Factor is comparable to the approach used in PEG's recent reports to the Board as part of the development of the 4th Generation Incentive Rate-setting for electricity distributors.[50] PEG recommends a composite I Factor (called an industry input price index ("IPI") in PEG's reports) comprised of a weighted average of separate input price indices for capital, labour and materials, and the weights are determined using the input sub-index average cost weights from their TFP analysis.

C. I Factor Forecast

Concentric developed a forecast of each of the price indices contained in the I Factor recommended to evaluate EGD's Allowed Revenue amounts. Because we believe that the Canadian government does not publish forecasts of these indices, Concentric prepared forecasts, based on our estimates of the historical relationship between each index and the broader Consumer Price Index ("CPI") for Canada, which does have an available forecast.[51]

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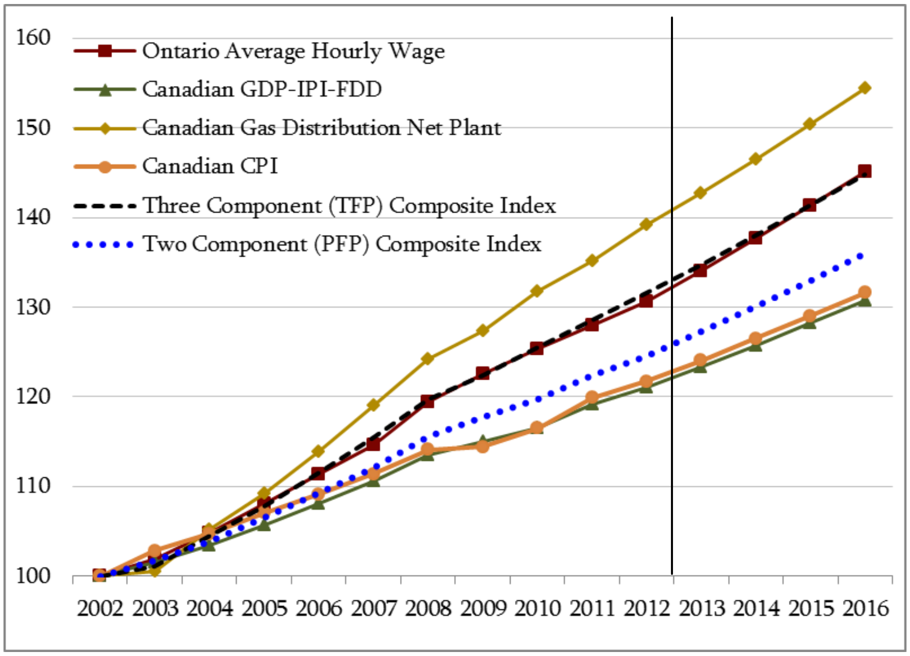
50 Pacific Economics Group Research, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board," May 3, 2013, subsequently revised May 31, 2013.

51 *Consensus Forecasts,* Consensus Economics, October 8, 2012, p.28.

Based on the historical relationship between Canadian CPI and each of the three sub-indices (measured through simple linear regressions), projections were developed for each of the three sub-indices. These sub-index forecasts were aggregated, using the historical weights, to create projections for both the two and three-component composite I Factors. The projections for each sub-index and the composite indices are presented in Figure 22.

Figure 22: Graph of Projected I Factor Price Indices



The following I Factor growth forecasts are used to evaluate Enbridge's Allowed Revenue amounts for the 2014 to 2016 period.

Figure 23: Projected Percent Annual Change in I Factor Price Indices

	2013	2014	2015	2016
Canadian CPI	1.90%	2.00%	2.00%	2.00%
Ontario Average Hourly Wage	2.62%	2.66%	2.66%	2.66%
Canadian GDP-IPI-FDD	1.88%	1.96%	1.96%	1.96%
Canadian Gas Distribution Net Plant	2.56%	2.66%	2.66%	2.66%
Three Component (TFP) Composite Index	2.36%	2.45%	2.45%	2.45%
Two Component (PFP) Composite Index	2.18%	2.24%	2.24%	2.24%

VI. TREATMENT OF O&M COSTS

EGD's proposed Customized IR plan sets the Company's Allowed Revenue amounts based on the Company's annual forecast of O&M costs, depreciation costs, taxes and cost of capital. This section presents and evaluates EGD's forecast O&M cost component of the Allowed Revenue amounts for 2014 to 2016.[52]

Figure 24 contains EGD's 2013 Board-approved O&M costs, as well as EGD's forecasted O&M budgets for 2014 to 2016. Total O&M expenses have been separated into (a) flow-through items, which are subject to fixed budgets approved in separate proceedings (i.e., Customer Care, Pensions, and DSM), and (b) all other O&M. For comparison purposes, EGD's 2013 Board-approved, and 2014 to 2016 forecasted customer count and resulting forecasted O&M costs per customer are also contained in Figure 24.

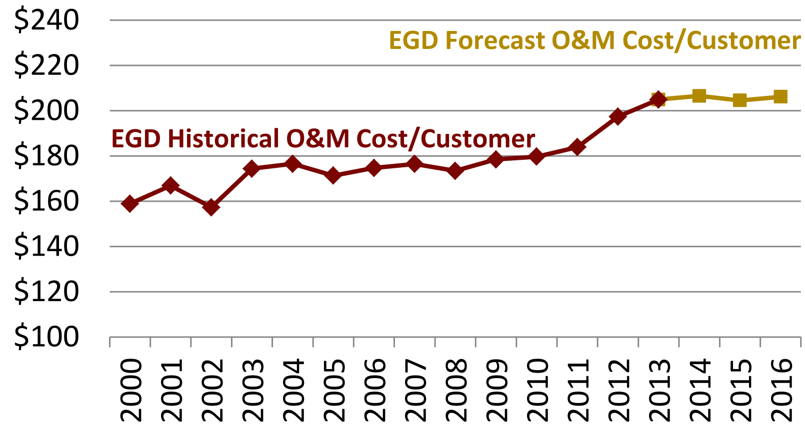
Figure 24: EGD O&M Costs, Customers, and O&M Costs/Customer

	2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast
Customer Care, Pensions, DSM ($Millions)	$164	$162	$163	$165
All Other O&M ($ Millions)	$251	$263	$265	$275
Total Utility O&M Expense ($ Millions)	**$415**	**$425**	**$429**	**$440**
Customer Count	2,025,462	2,059,619	2,095,302	2,131,887
Total O&M Cost per Customer ($/Customer)	$205	$207	$205	$206

To test the reasonableness of EGD's 2014 to 2016 O&M budget, Concentric performed two analyses. First, Concentric compared EGD's total forecast O&M cost per customer to EGD's historical trend of total O&M costs per customer. As noted in Figure 7 in the benchmarking discussion, EGD's O&M cost per customer is already among the lowest in the industry; in 2011 EGD had the fifth lowest O&M cost per customer in an industry study group comprised of 28 U.S. natural gas utilities. As shown in Figure 25, EGD's forecasted O&M cost per customer is forecasted to be higher than recent history, but not by a significant amount.

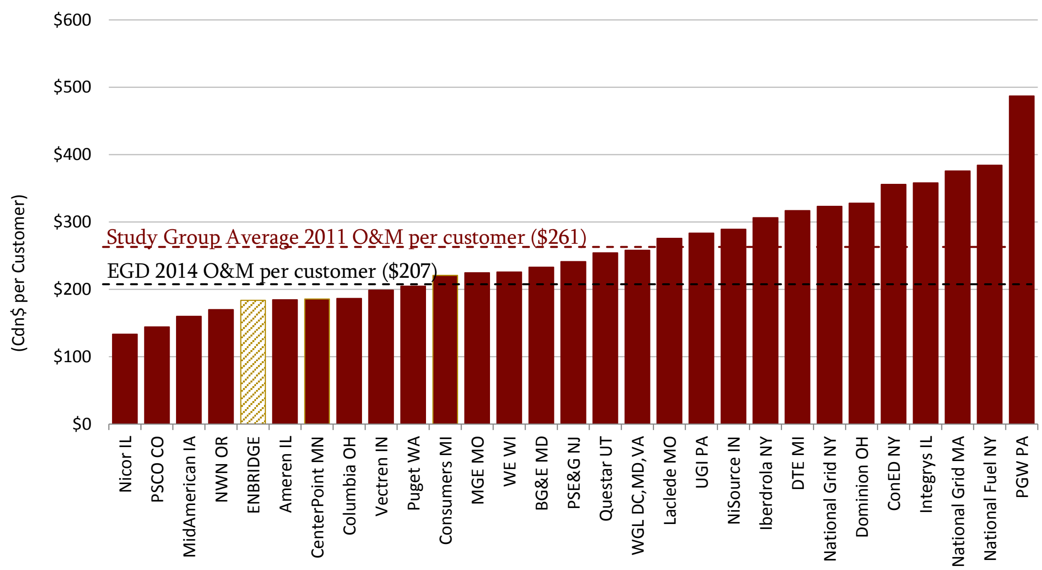
52 Concentric's assessment of EGD's forecast capital cost component of the Allowed Revenue amounts for 2014 to 2016 is provided in Section VII.

Figure 25: EGD O&M Costs/Customer (2000-2016)



It is also notable that EGD's forecasted O&M cost per customer of $207 in 2014 is significantly lower than the industry study group average of $261 for 2011.

Figure 26: Total 2011 Gas O&M Expenses per Customer with EGD 2014 Total O&M Cost per Customer Forecast[53]



For the second analysis, Concentric compared EGD's forecasted Total O&M cost per customer with the O&M cost per customer that is derived from (a) applying the projected PFP I-X growth rates to the "all other" O&M category of costs per customer, plus (b) EGD's

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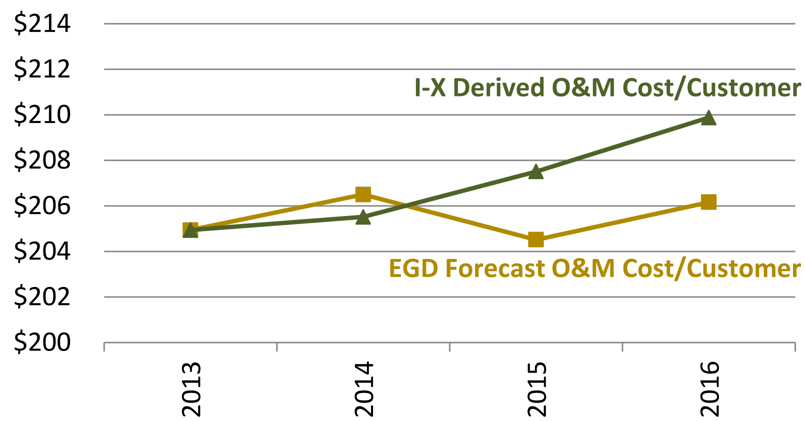
[53] The 2011 and 2014 O&M cost per customer data are presented in nominal Canadian dollars. If the effects of inflation were removed from EGD's 2014 forecast O&M cost per customer, EGD's 2014 forecast would be even lower.

projected Customer Care, Pensions and DSM pass-through costs.[54] As shown in Figure 23 in Section V.C (Measure of Inflation), the two-component composite I Factor is projected to grow at 2.24% per year from 2014 to 2016. This combined with a PFP X Factor of 0% implies that "All Other" (Non-flow through) O&M cost per customer would be expected to increase by 2.24% under a PFP I-X framework applied to O&M costs. A comparison of EGD's forecasted total O&M cost per customer and the O&M cost per customer derived from applying the PFP I-X formula to the non-flow through O&M costs per customer is shown in Figure 27:

Figure 27: EGD O&M Costs/Customer versus PFP I-X ($/Customer)

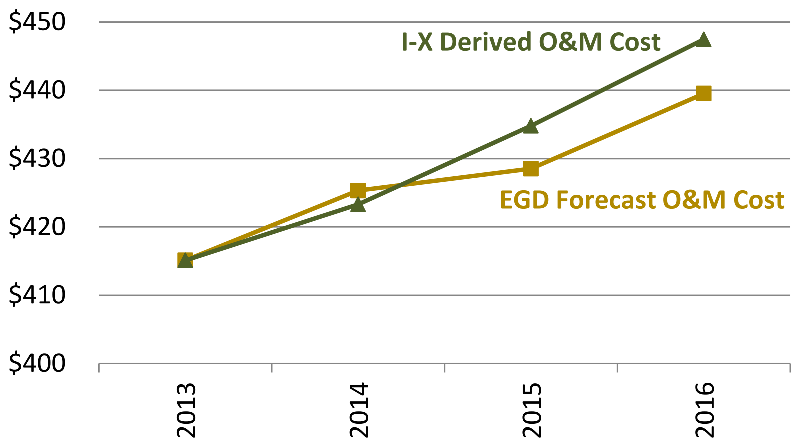


As shown in Figure 27 above, EGD's forecasted O&M cost per customer is higher than the O&M cost per customer derived from applying the PFP I-X formula in 2014 and is lower than the O&M cost per customer derived from applying the PFP I-X formula in 2015 and 2016.

Figure 28 demonstrates EGD's forecasted O&M cost in aggregate is approximately $2 million higher than the PFP I-X derived O&M cost in 2014, $6 million less in 2015 and $8 million less in 2016, for a cumulative 2014 to 2016 productivity savings, compared to I-X O&M growth of approximately $12 million, compared to the PFP I-X formula.

54 Costs associated with Customer Care, Pensions and DSM have been determined by the Board to be pass through costs in Board decisions in other proceedings.

Figure 28: EGD O&M Costs versus PFP I-X ($Millions)



Concentric's analyses indicate that EGD's forecasted O&M costs are reasonable based on a comparison to the benchmark utilities, and in relation to productivity from the seven company sub-group PFP analysis. The $12 million in cumulative savings between the PFP I-X derived O&M costs and the EGD forecasted O&M cost can be viewed as additional productivity flowing through to customers, beyond the productivity that would be built into a PFP I-X formula.

VII. TREATMENT OF CAPITAL COSTS

A. Introduction

EGD asked Concentric to assess EGD's proposed approach to recover the costs of its projected 2014 to 2016 capital spending. This Section provides a summary of Concentric's assessment. Also included is (1) an overview of traditional and non-traditional ratemaking approaches that are currently being used in Canada and the U.S. to recover capital costs; and (2) a summary of Concentric's analyses that measure the effect of these capital cost recovery ratemaking approaches on EGD's opportunity to earn a fair return. The overview of ratemaking approaches and the summary of Concentric's analyses serve as the basis for Concentric's assessment.

B. Recovery of Capital Costs

Traditional cost of service / rate of return regulation, as practiced by provincial and state regulatory agencies, is based on an analysis of a utility's projected or historical annual cost of doing business; this analysis determines the level of revenues ("revenue requirement")[55] that would allow the utility a reasonable opportunity to earn a fair rate of return.[56]

In simple terms, the rates that are charged to customers are determined by dividing the revenue requirement by the units of sales; the units of sales are determined in a manner that is intended to be representative of the sales that are likely to be experienced in the period when the new rates will take effect.[57] Lastly, customer charge rates, volumetric rates and demand rates to be billed to customers in each rate class are calculated.

Traditional ratemaking is designed to provide regulated utilities with a reasonable opportunity to earn a fair rate of return if the conditions that affect utility costs and revenues

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[55] The revenue requirement consists of (1) expenses, (2) return of investment in plant (depreciation), (3) return on investment in plant, and (4) taxes. The return on investment component of the revenue requirement accounts for the cost of debt that the utility has issued and the cost of equity, which is determined by analysis to be the return that will allow the utility to maintain credit, attract investment and provide returns that are comparable to like-risk investments.

[56] Typically, when the rate making process is based on historical data, adjustments are made to the data to ensure that the historical costs are representative of the costs that are likely to be experienced in the future period when the new approved rates will take effect.

[57] The detailed determination of the rates to be charged involves (a) assigning an appropriate and fair portion of the total revenue requirement to each of the rate classes that receives service from the company, and (b) separating the class revenue requirement into the portions that will be recovered from each of the types of units of sales – billing determinants - that apply to that rate class, e.g. customer, commodity or energy, and demand.

during the period that the rates will be charged are generally similar to the conditions that formed the basis for the approved rates; traditional ratemaking may not produce reasonable results when the conditions that affect utility costs and revenues in the years that the rate case rates will be charged are very different from the conditions that formed the basis for the approved rates.[58]

There has been growing recognition over the past decade among regulators and gas distribution companies that traditional ratemaking is not likely to produce reasonable results[59] because of the business and operating conditions that that are impacting the earnings of gas distribution companies. These business and operating conditions include, for example: (a) the implementation of large safety and reliability-related non-revenue producing infrastructure replacement and reinforcement programs and/or (b) limited growth in revenues as a result of utility-sponsored energy efficiency programs and general implementation of conservation measures. Under these conditions, traditional ratemaking would not provide a gas distribution company with a reasonable opportunity to earn a fair return. Further, filing frequent rate cases is not a viable solution to the shortcomings of traditional ratemaking. In addition to the administrative inefficiencies of frequent rate cases, which impact all parties, frequent rate cases will not provide a gas distribution company with a reasonable opportunity to earn a reasonable return because of delays that are inherent in the rate case process.[60]

As a result of the shortcomings of traditional ratemaking under these circumstances, over the last several years[61] a growing number of regulators have approved non-traditional rate making approaches to (a) allow for timely recovery of the costs of capital spending between rate cases; (b) offset the impact of declining delivery volumes on distribution revenues; and /

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58 Also, traditional ratemaking may not produce reasonable results even when the conditions that affect utility costs and revenues in the years that the rate case rates will be charged are the same as the conditions that formed the basis for the approved rates, such as during an extended period of high rates of inflation.

59 This discussion is limited to gas distribution companies, although traditional ratemaking approaches have not been producing reasonable results for electric distribution companies in recent years as well.

60 These delays in the rate case process, often referred to as "regulatory lag," include the time between (a) the time period represented by the historical costs that are the basis for determining a distribution company's revenue requirement and (b) the effective date of the new rates that reflect the distribution company's revenue requirement.

61 Although much of the attention to non-traditional ratemaking approaches has occurred since 2005, in 1978, Pacific Gas & Electric's gas division ("PG&E) implemented a non-traditional ratemaking approach to decouple PG&E's revenues and earnings from the volumes of gas delivered so that PG&E earnings would not be impacted by the extensive energy efficiency programs that PG&E was implementing.

or (c) allow for timely recovery of specific types or categories of expenses that are largely variable from year to year.

Specifically related to EGD's request that Concentric assess EGD's proposed approach to recover the costs of its projected capital spending during EGD's Customized IR plan, there is considerable recent experience in Canada and the U.S. concerning non-traditional ratemaking approaches that allow for timely recovery of the costs of capital spending between rate cases;[62] these ratemaking approaches are often referred to as Capital Trackers. Figure 29 summarizes the three most common Capital Tracker approaches.

Figure 29: Capital Tracker Approaches

Category	Types of Eligible Assets	Examples of Eligible Assets
General Purpose	• Typically non-revenue generating • Targeted • Long term • Out of the ordinary	• Cast iron/ bare steel replacement programs • Pipeline system integrity • Relocating inside gas meters • City and state construction projects
Special Projects	• Very large • Defined, specific projects • Short term • May include revenue generating projects	• Specific system expansion / system growth areas • Reinforcement projects • Automated meter reading devices
Comprehensive	• All capital spending	• All capital spending

The most common application of General Purpose Capital Trackers is to provide for recovery of the costs associated with accelerated replacement of leak-prone distribution assets.[63] General Purpose Capital Trackers typically are designed to recover the revenue

62 There is also considerable recent experience in Canada and the U.S. related to non-traditional ratemaking approaches to offset the impact of declining delivery volumes on distribution revenues; and to allow for timely recovery of specific types or categories of expenses that are largely variable from year to year. However, these non-traditional ratemaking approaches are not directly relevant to EGD's 2nd Generation IR proposal.

63 Regulatory policies to promote accelerated replacement of leak prone assets are driven by public safety considerations in jurisdictions where leak-prone assets are a significant portion of total distribution mains and services.

requirement[64] associated with qualifying General Purpose facilities that are not reflected in the base distribution rates.[65] Annually, base distribution rates are increased by a special rate surcharge or by adjustments to base distribution rates to recover the General Purpose Capital revenue requirement. General Purpose Capital Trackers generally do not restrict the timing of the distribution company's next base rate case[66] and a General Purpose tracker mechanism may remain in effect for many years, depending on the duration of the General Purpose Capital program.[67]

Special Project Capital Trackers are generally used to recover the costs of large single projects of relatively short duration, such as major main extension projects, system improvement / reinforcement projects, and integrity management initiatives. The structures of Special Project and General Purpose Capital Trackers are very similar; typical Special Project Capital Trackers recover the revenue requirement[68] associated with the Special Project through annual increases to base distribution rates. Special Project Capital Trackers generally do not restrict the timing of the distribution company's next base rate case.[69] A Special Project tracker mechanism would usually remain in effect only until the distribution company's next base rate case, if the completed project is included in the rate case plant and rate base balances.

Lastly, Comprehensive approaches to recover the costs of all capital spending generally include (a) multi-year rate plans that account for the distribution company's (i) capital

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64 The revenue requirement for a General Purpose Capital Tracker includes depreciation on the General Purpose Plant; return on the General Purpose net plant (total gross Plant less accumulated depreciation); income taxes and property taxes.

65 General Purpose Trackers generally recover the costs of qualifying facilities that have placed into service, although some General Purpose Trackers provide for initial filings that include projected data, which is updated with actual data during the regulatory review period, prior to the approval of the general purpose increase in rates.

66 However, a rate plan with a General Purpose Capital Tracker mechanism may also include a "stay out" provision.

67 For example, even at an accelerated rate of replacement, some replacement programs may continue for 20 or more years. See, for example, National Grid Massachusetts, D.P.U. 10-55, November 2, 2010 Order, page 98.

68 The revenue requirement for a Special Project Capital Tracker includes depreciation on the Special Project Plant; return on the Special Project net plant (total gross Plant less accumulated depreciation); income taxes and property taxes.

69 However, a rate plan with a Special Project Capital Tracker mechanism may also include a "stay out" provision.

spending plans and (ii) projected expenses,[70] and (b) formulaic rate adjustments to recover annual revenue requirements, based on historical audited financial reporting.[71] These comprehensive multi-year rate plans provide annual rate adjustments for a specified period based on fixed annual revenue requirements that have been developed based on projected O&M expenses and projected plant and rate base, using a process that is often referred to as a "Building Blocks" methodology. The Building Block approach is discussed in more detail in the report on incentive ratemaking frameworks prepared for EGD by London Economics International LLC.

C. Assessment of EGD's Proposed Capital Recovery Approach

1. Introduction

The Capital Trackers listed in Figure 29 generally correspond to the rate setting approaches for the recovery of capital costs during the terms of electric IR plans that the Board has identified in the Renewed Regulatory Framework ("RRF") for Electricity (October 18, 2012). That is, (a) the Incremental Capital Module component of the 4th Generation IR is similar to (i) a General Purpose or (ii) a Special Project Capital Tracker, and (b) the Custom IR is similar to the Building Blocks-type Comprehensive ratemaking approach. The RRF Custom IR approach is also similar to EGD's proposed Customized IR plan.

To assess EGD's proposed approach to recover the costs of its projected capital spending, Concentric prepared analyses of EGD's projected 2014 to 2016 capital-related revenues and revenue requirements. Concentric calculated projected capital-related revenue requirements based on data provided by the Company. Projected revenues were developed for four scenarios; base case revenues were based on capital-related rebasing revenues with annual I-X revenue increases, and capital-related revenues for the three additional scenarios were based on I-X revenue increases, plus incremental revenue recovery produced by each of the three commonly-used capital recovery approaches. The four scenarios are summarized below:

Rate Option 1: I-X revenue per customer adjustment mechanism
Rate Option 2: General Purpose Capital Tracker, combined with an I-X revenue per customer adjustment mechanism

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[70] Multi-year rate plans have been approved for gas distribution companies in California and New York, and proposed by FortisBC.

[71] These annual formulaic rate adjustments, commonly referred to as "revenue stabilization" adjustments, have been approved for gas distribution companies in Alabama, Georgia, Louisiana, Oklahoma, South Carolina, Texas, and Vermont.

Rate Option 3: Special Project Capital Tracker, combined with an I-X revenue per customer adjustment mechanism
Rate Option 4: Customized IR (EGD's Proposed Approach)

2. *Capital-Related Revenue Requirement and Revenues*

A utility's capital-related revenue requirement for a specific year includes (1) return of investment in plant (depreciation), (2) return on investment in plant, and (3) taxes. As explained in Section VII.B, the components of the capital-related revenue requirement for a specific year - depreciation expense, return on investment in plant[72], and taxes - are based on (a) plant and rate base records and (b) certain factors, such as depreciation rates, tax rates, and rate of return on rate base, which are generally reviewed by regulators during a rebasing or traditional COS proceeding. Changes in the capital-related revenue requirements from year-to-year are caused by changes in plant in service and changes in rate base.[73]

Capital-related revenues are initially set by the regulators in a rebasing or traditional COS proceeding based on the regulator's determination of the capital-related revenue requirement that reflects the utility's on-going costs of providing service. Annual changes in a utility's capital-related base distribution revenues, relative to the allowed revenues in the utility's most recent rebasing or COS proceeding, reflect (a) changes in the total billing units – fixed, volumetric and demand – that are charged to the utility's customers and (b) changes in rates as provided for in the utility's rate plan.

3. *Concentric's Capital-related Revenue and Revenue Requirement Models*

For each of the four Rate Options listed in Section VII.C.1, Concentric calculated projected 2014 to 2016 capital-related revenues and revenue requirements.

EGD's annual revenue requirements were calculated according to the following Equation 1:

$$\text{Revenue Requirement}_{\text{year i}}^{\text{Plant-related}} = \text{ROR}^{\text{pretax}} \text{ x Rate Base}_{\text{year i}} + \text{Depreciation Expense}_{\text{year i}} \qquad \text{[Equation 1]}$$

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72 Return on investment is the product of (a) allowed return and (b) rate base; rate base is the total original value of plant in service, reduced by the accumulated depreciation on the plant in service.

73 Changes in plant result from additions to plant, net of plant retirements. Changes in rate base result from additions to plant, net of retirements and changes in accumulated depreciation.

Where:

$$year_i = (2014, 2015, 2016)$$

$$\text{ROR}^{\text{pretax}} = Allowed\ Weighted\ Average\ Cost\ of\ Capital, before\ taxes$$[74]

$$RateBase_{year\ i} = Plant_{year\ i} - Accumulated\ Depreciation_{year\ i}$$

$$\text{Depreciation Expense}_{\text{year i}} = Plant_{year\ 1}\ x\ Depreciation\ Rate_{year\ i}$$

EGD's annual revenues (not including incremental Capital Recovery revenues associated with Rate Options 2 and 3) were calculated according to the following Equation 2[75]:

$$Revenues_{year\ i} = RevReq_{Rebasing}^{Plant-related}\ x\ (1 + P_{year\ i})\ x\ (1 + G_{year\ i}) \qquad \text{[Equation 2]}$$

Where:

$$year_i = (2014, 2015, 2016)$$

$$RevReq_{Rebasing}^{Plant-related} = ROR^{pretax}\ x\ Rate\ Base_{Rebasing} + Plant_{Rebasing}\ x\ Combined\ Depreciation\ Rate$$

$$P_{year\ i} = Percent\ increase\ in\ revenue\ per\ customer\ cap, determined\ according\ to\ projected\ values\ in\ year\ i\ for\ I\ and\ X$$

$$G_{year\ i} = Percent\ increase\ in\ projected\ number\ of\ customers\ in\ year\ i$$

Concentric's Capital-related Revenue and Revenue Requirement models do not include (a) taxes on depreciation expense or (b) property taxes. Concentric, with advice from the Company related to Canadian tax issues, determined that excluding the tax effect on depreciation from both the revenue and revenue requirement calculations would not have a significant impact on the model results, and would simplify the model calculations. Concentric and the Company similarly determined that excluding property taxes from both

74 $\text{ROR}^{\text{pretax}}$ for EGD is calculated by dividing Allowed weighted average cost of capital, after taxes by (1 – the combined effect of federal and provincial tax rates)

75 Rate Option 2, incremental General Purpose Capital revenue calculations are shown in Figure 32, lines 17 to 29; Rate Option 3 incremental Special Project Capital revenue calculations are shown in Figure 34, lines 16 to 22 and Rate Option 4 Customized Capital revenue calculations are shown in Figure 36, line 10.

the revenue and revenue requirement calculations would not materially impact the model results.

The Company provided rebasing and 2014 to 2016 data for plant, rate base, depreciation rates, income tax rates, cost of capital, and accumulated depreciation. EGD also provided estimates of the rate of growth in customers from 2014 to 2016. The projected I-X revenue increases are based on Concentric's X factor (Section IV) and I Factor (Section V) recommendations.

4. Model Results

a. Rate Option 1: I-X

Figure 30 provides Concentric's analysis of EGD's projected 2014 to 2016 capital-related revenue requirements, I – X revenues, and revenue deficiencies if EGD rates were increased annually from 2014 to 2016 by the I-X escalation formula, with no additional mechanism to recover incremental capital costs.

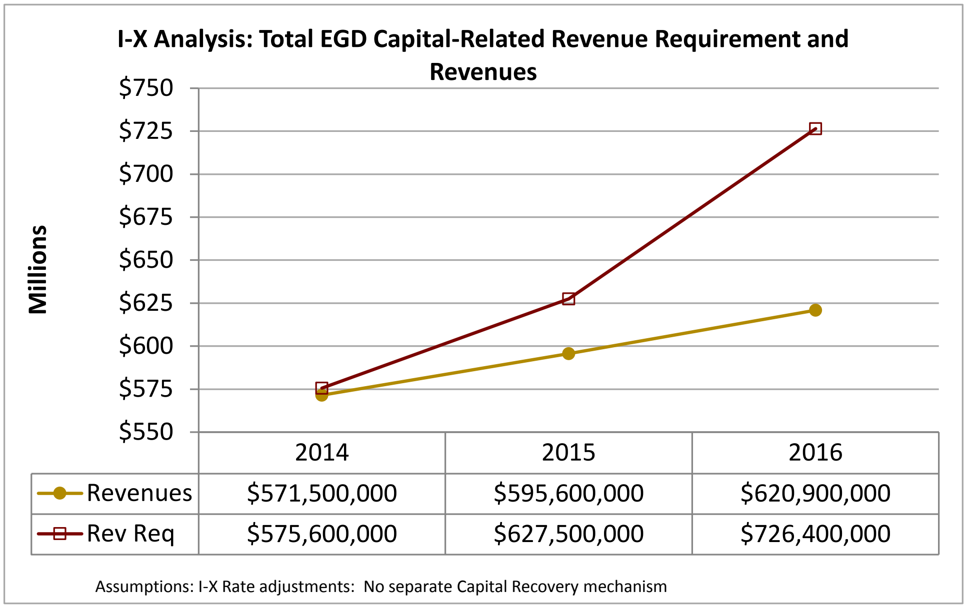
Figure 30 Rate Option 1: Revenues based on I-X rate adjustments

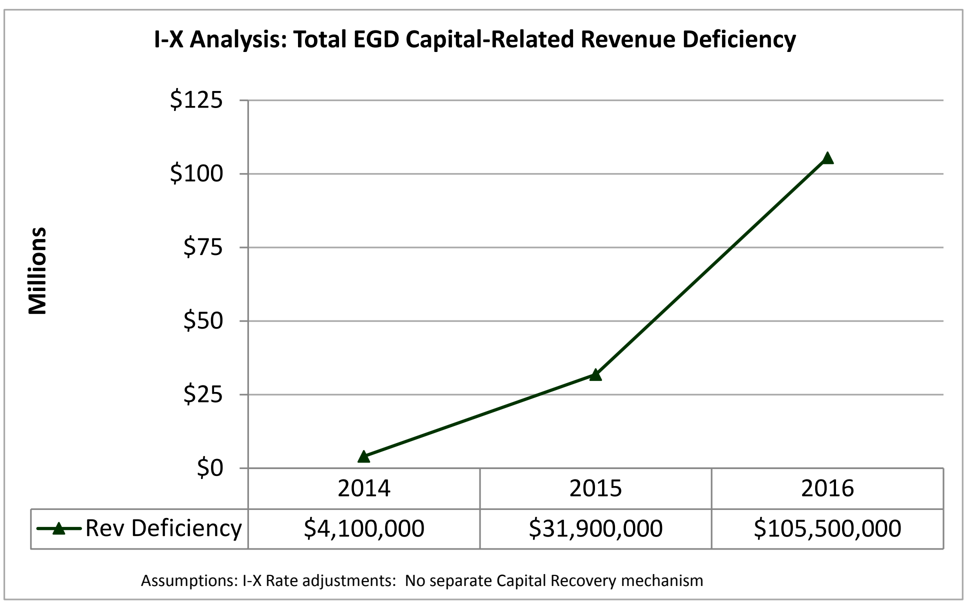
		2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$6,977,000,000	$7,441,000,000	$8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense ("DeprExp")	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return - DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15				
16	$Revenues^{Plant\text{-}related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
17				
18	Deficiency (Surplus) in Revenues	$ 4,100,000	$ 31,900,000	$ 105,500,000

Figure 31 provides a graphical representation of the Rate Option 1 capital-related revenues, revenue requirements and revenue deficiencies.

It is Concentric's assessment that Figures 30 and 31 demonstrate that an I-X escalation formula does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year capital-related revenue deficiency is $141.5 million.

Figure 31: Rate Option 1: Revenues, Revenue Requirement, and Revenue Deficiency





b. Rate Option 2: I-X plus General Purpose (ICM-type) Capital Tracker

For the Rate Option 2 analysis, Concentric modeled the General Purpose tracker using the Ontario 3rd and 4th Generation Electric ICM Threshold formulas. Figure 32 provides Concentric's analysis of EGD's projected 2014 to 2016 capital-related revenue requirements, I

– X plus ICM revenues, and revenue deficiencies if EGD rates were increased annually from 2014 to 2016 by the I-X escalation formula, with additional revenues to recover plant additions above a threshold level.[76]

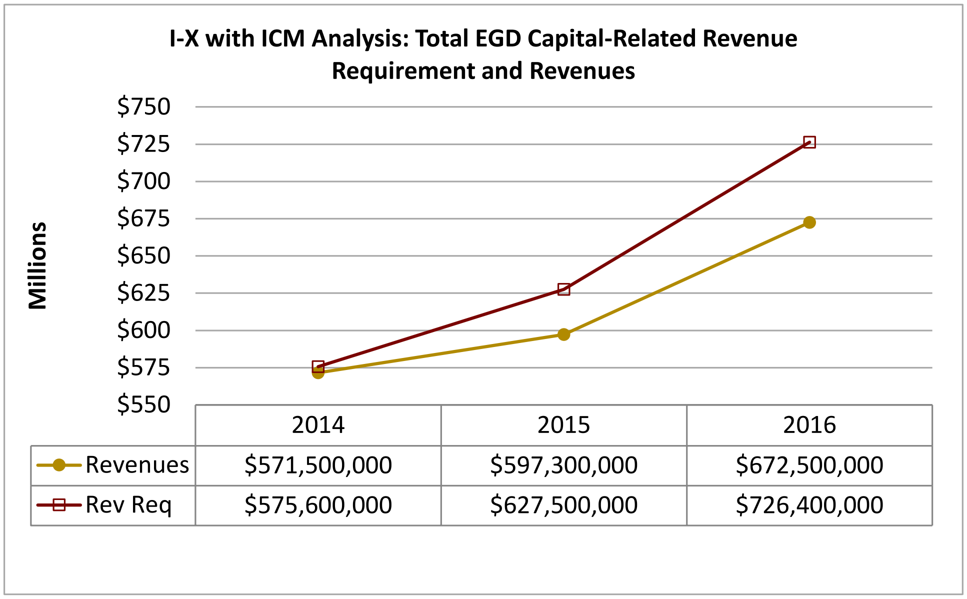
Figure 32: Rate Option 2: Revenues based on I-X and General Purpose Capital Tracker

		2014	2015	2016
1	Revenue Requirement			
2	Average of Monthly Avgs Plant	$ 6,977,000,000	$ 7,441,000,000	$ 8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense (“DeprExp”)	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	RORPretax	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return - DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15	I-X Revenues$^{\text{Plant-related}}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
16				
17	**THRESHOLD CALCULATION** $Threshold = 1.2\ x\ DeprExp_{rebasing} + Rate\ Base_{rebasing}\ x\ (P + G + PxG)$			
18	(G + P + P x G)	4.173%	4.222%	4.237%
19	$Rate\ Base_{Rebasing}\ x\ (G + P + GxP)$	$ 162,300,000	$ 164,200,000	$ 164,800,000
20	$1.2\ x\ DeprExp_{rebasing}$	$ 284,800,000	$ 284,800,000	$ 284,800,000
21	Threshold	$ 447,100,000	$ 449,000,000	$ 449,600,000
22				
23	Plant Additions	$ 218,400,000	$ 463,900,000	$ 880,900,000
24	Plant Additions above Threshold	$ -	$ 14,900,000	$ 431,300,000
25	Total Plant Above Threshold	$ -	$ 14,900,000	$ 446,200,000
26	Depreciation	$ -	$ 500,000	$ 15,600,000
27	Accumulated Depreciation	$ -	$ 500,000	$ 16,100,000
28	Rate Base above Threshold	$ -	$ 14,400,000	$ 430,100,000
29	ICM Revenues	$ -	$ 1,700,000	$ 51,600,000
30				
31	Total Revenues	$ 571,500,000	$ 597,300,000	$ 672,500,000
32	Deficiency (Surplus) in Revenues	$ 4,100,000	$ 30,200,000	$ 53,900,000

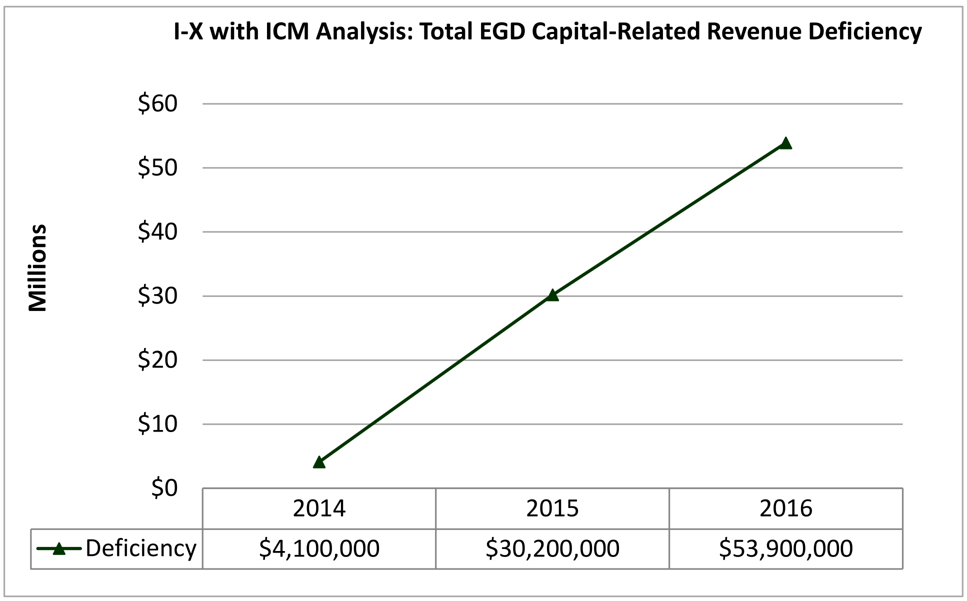
[76] The ICM Threshold calculations are shown in Figure 34, lines 17 to 21.

Figure 33 provides a graphical representation of the Rate Option 2 capital-related revenues, revenue requirements and revenue deficiencies.

Figure 33: Rate Option 2: Revenues, Revenue Requirement, and Revenue Deficiency



	2014	2015	2016
Revenues	$571,500,000	$597,300,000	$672,500,000
Rev Req	$575,600,000	$627,500,000	$726,400,000



	2014	2015	2016
Deficiency	$4,100,000	$30,200,000	$53,900,000

It is Concentric's assessment that Figures 32 and 33 demonstrate that an I-X escalation formula combined with an ICM-type mechanism does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year capital-related revenue deficiency is $88.2 million.

c. Rate Option 3: I-X plus Special Project Capital Tracker

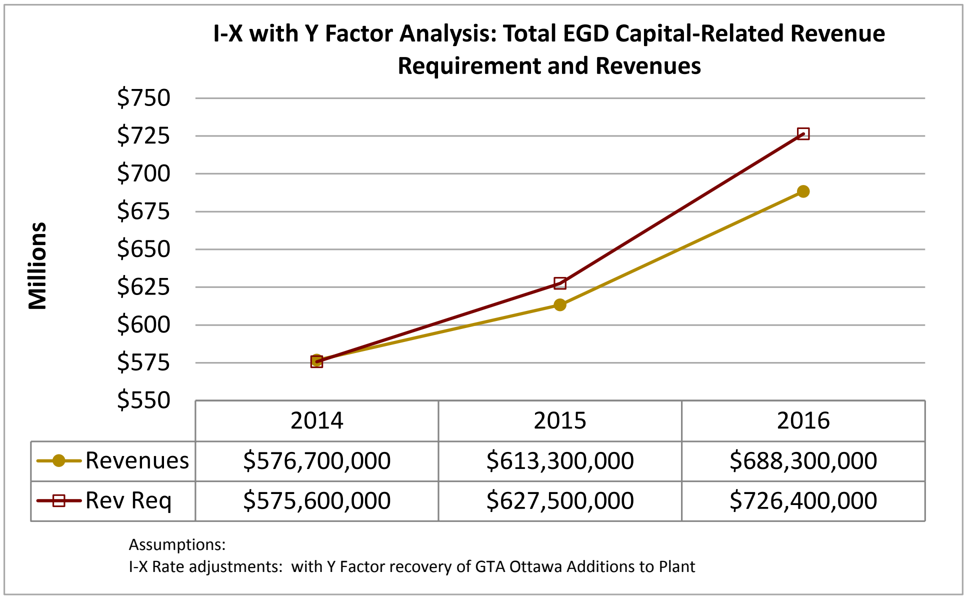
For the Rate Option 3 analysis, Concentric modeled the Special Project tracker on a Y Factor type capital recovery mechanism that recovers the revenue requirements associated with the Company's Ottawa and GTA reinforcement projects. Figure 34 provides Concentric's analysis of EGD's projected 2014 – 2016 capital-related revenue requirements, I – X plus Y Factor revenues, and revenue deficiencies if EGD rates were increased annually during the 2014 to 2016 period by the I-X escalation formula, with additional Y Factor revenues.

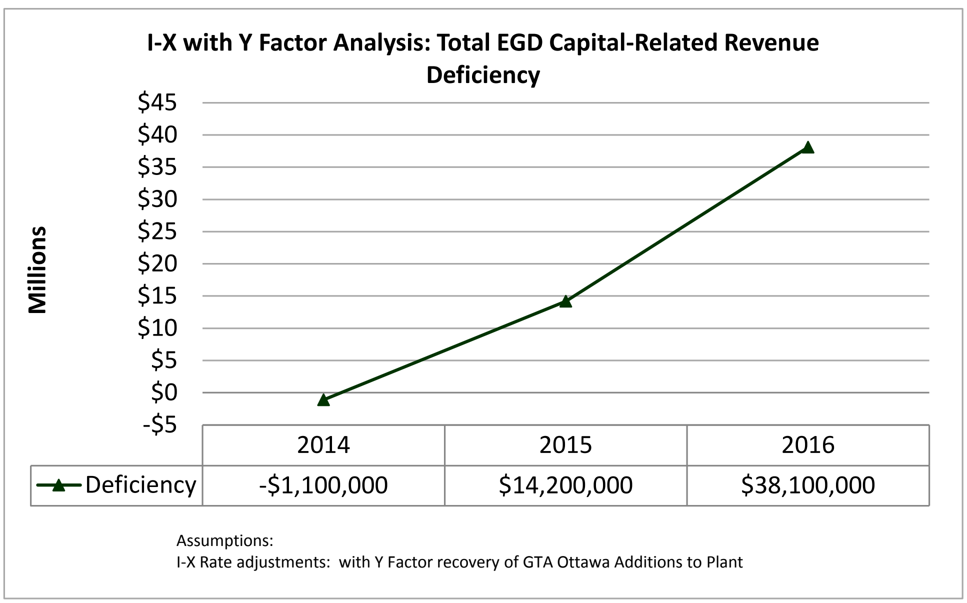
Figure 34: Rate Option 3: Revenues based on I-X plus Special Project Capital Tracker

		2014	2015	2016
	Revenue Requirement			
2	Average of Monthly Avgs Plant	$ 6,977,000,000	$ 7,441,000,000	$ 8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense ("DeprExp")	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return - DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15	I-X $Revenues^{Plant-related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
16	GTA, Ottawa Plant	$ 48,900,000	$ 172,100,000	$ 631,900,000
17	Depreciation Rate	2.66%	2.21%	2.47%
18	GTA, Ottawa Depreciation Expense	$ (1,300,000)	$ (3,800,000)	$ (15,600,000)
19	GTA, Ottawa Rate Base ("RB")	$ 48,400,000	$ 169,900,000	$ 619,100,000
20	ROR^{Pretax}	7.98%	8.19%	8.36%
21	GTA, Ottawa Return: ROR Pretax x RB	$ 3,900,000	$ 13,900,000	$ 51,800,000
22	GTA, Ottawa Revenue Requirement	$ 5,200,000	$ 17,700,000	$ 67,400,000
23	Total Revenues (I-X plus Y Factor)	$ 576,700,000	$ 613,300,000	$ 688,300,000
24				
25	Revenue Deficiency (with I-X and Y Factor)	$ (1,100,000)	$ 14,200,000	$ 38,100,000

Figure 35 provides a graphical representation of the Rate Option 3 revenues, revenue requirements and revenue deficiencies.

Figure 35: Rate Option 3: Revenues, Revenue Requirement, and Revenue Deficiency





It is Concentric's assessment that Figures 34 and 35 demonstrate that an I-X escalation formula combined with Y Factor Recovery of the GTA and Ottawa projects does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $51.2 million.

d. Rate Option 4: Customized IR (EGD's Proposed Approach)

The modeling for the capital-related revenues and revenue requirements for EGD's proposed Customized IR is straight-forward: the capital-related revenues are projected to be equal to the capital-related revenue requirement. Figure 36 provides Concentric's analysis of EGD's projected 2014 – 2016 capital-related revenue requirements and Customized IR revenues.

Figure 36: Rate Option 4: Revenues based on EGD's Proposed Customized IR Approach

		2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$ 6,976,900,000	$ 7,440,900,000	$ 8,321,800,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense ("DeprExp")	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return + DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Total Revenues (Customized IR)	$ 575,600,000	$ 627,500,000	$ 726,400,000

5. Summary

EGD's opportunity to earn a reasonable return is a key consideration in the overall assessment of IR ratemaking options, and Concentric's analysis of EGD's Capital-related revenues and revenue requirements for each of the four ratemaking options is a primary factor that will affect EGD's opportunity to earn a reasonable return[77]. Figure 37 demonstrates that three of the commonly used capital recovery ratemaking options would create capital-related revenue deficiencies of at least $51.2 million and as much as $141.5 million over the 2014 to 2016 period. Considering capital-related revenues and revenue requirements, only the Customized IR approach would provide EGD with a reasonable opportunity to earn a fair return.

77 Concentric's overall evaluation of EGD's proposed IR plan, which takes into account several other factors, in addition to Capital-related revenues and revenue requirements, is provided in Section IX.

Figure 37: Summary of Capital Recovery Options Revenue Deficiencies

		Revenue Deficiencies			
		2014	2015	2016	3 Year Total
1	Rate Option 1: I-X	$ 4,100,000	$ 31,900,000	$105,500,000	$141,500,000
2	Rate Option 2: I-X plus ICM	$ 4,100,000	$ 30,200,000	$ 53,900,000	$88,200,000
3	Rate Option 3: I-X plus Y Factor	$ (1,100,000)	$ 14,200,000	$ 38,100,000	$51,200,000
4	Rate Option 4: Customized IR	$ -	$ -	$ -	$ -

VIII. EARNINGS SHARING MECHANISM ("ESM")

A. Introduction

EGD asked Concentric to review EGD's proposed ESM and provide our perspective regarding the reasonableness of EGD's proposed ESM, given the overall structure of EGD's proposed program. This section provides an overview of ESMs based on our experience, and our evaluation of EGD's proposed ESM.

Generically, an ESM is a ratemaking tool that provides for sharing between customers and shareholders of earnings that are either above or below the level of earnings that would produce the authorized return on equity ("ROE"). Customer rates are adjusted either downward (when there are surplus earnings) or upward (when there is an earnings shortfall) to account for the customer portion of the earnings that are to be shared.

ESMs often incorporate a "deadband" around the authorized ROE within which the utility absorbs 100% of the variance in earnings; there is no customer sharing within the deadband. Sharing occurs when earnings fall outside of the deadband; this earnings surplus or shortfall is shared between the utility and its customers according to prescribed proportions (e.g., 50% to the utility; 50% to customers).

B. Evaluation of EGD's Proposed ESM

Concentric understands that EGD is proposing an ESM with a deadband of 100 basis points above the authorized ROE (updated annually according to the approved formula), the same as that approved for EGD's 1st Generation IR Plan. If the actual, weather normalized, ROE exceeds the authorized ROE by more than 100 basis points; the excess will be split evenly between customers and the Company. Earnings more than +/- 300 basis points above/below the authorized ROE would trigger a regulatory review of the IR plan.

EGD's proposed ESM is consistent with the structure of ESMs employed elsewhere in Canada and the U.S., although there are many variations to the basic structure. Four important elements to consider are the size of the deadband, the sharing mechanism, whether the mechanism is symmetrical or not, and the re-opener provisions.

The size of the deadband is an important design element because it can affect management's incentives to pursue efficiencies. As the size of the deadband increases, management has an increased incentive to pursue efficiency gains because the utility retains a greater proportion of the benefits. Some ESMs do not have deadbands at all (i.e., sharing begins with the first dollar in excess of or below the allowed ROE) although this is less common. EGD's proposed deadband of 100 basis points is consistent with industry norms. Since it is based on weather normalized earnings, volatility related to weather is addressed elsewhere, which reduces the likelihood that earnings would fall outside the deadband. We would note, for the Board's consideration, that a larger ESM deadband would increase the Company's incentive to identify and implement incremental efficiency gains.

There are a variety of sharing proportions that are employed by North American utilities although 50-50, 75-25, and 25-75 (utility and customer proportions respectively) are the most common. Some ESMs have tiered sharing formulas, i.e., the sharing proportions are adjusted in tiers as earnings deviate further from the authorized ROE. Tiered formulas tend to have customer-sharing percentages that increase as earnings increase above the authorized ROE. EGD's proposed 50-50 sharing with customers above the deadband is a relatively common approach, and conveys a sense of equity between the company and its customers.

In some ESMs, both earnings surpluses and shortfalls are shared according to identical structures ("symmetrical ESMs"), while others apply different structures to surpluses and shortfalls ("asymmetrical ESMs"). The argument for symmetrical ESMs is that they balance the risk and reward prospects for the utility and customers. ESMs are most prevalent when there is a multi-year rate plan that precludes the utility from filing a rate case except under extraordinary circumstances, such as IR. As the term of a multi-year rate plan increases, there is a greater likelihood that revenues and/or expenses will deviate in ways that may not have been anticipated when the plan was approved. The ESM helps safeguard against an earnings outcome that may be unacceptable to either customers (or regulators on their behalf) or to the utility. In this respect, ESMs are a form of earnings variance management for the regulator. However, rather than focus narrowly on a particular revenue or expense circumstance that contributes to the variation in earnings, the ESM is designed to focus on the end result and thus captures all such contributing circumstances in a single measure. Since it is unknown whether the potentially unanticipated earnings deviations will be positive or negative, even-handed regulatory policy would suggest that it is appropriate to provide symmetrical safeguards for customers and the utility. While symmetrical ESMs balance the risk and reward prospects for the utility and customers, it is also common for ESMs to be asymmetrical. One example of an asymmetrical program is EGD's 1st Generation IR Plan.

Lastly, it is appropriate to include re-opener provisions[78] as part of EGD's ESM to protect against significant unanticipated results. Re-opener provisions are common in IR plans as an important safeguard to provide the company and the regulator the opportunity to re-evaluate

[78] Similarly, it is also appropriate to allow for Z Factors, to recover from customers or pass back to customers large unanticipated changes in costs that are outside of EGD's control.

the IR plan and determine what features are causing the significant deviation in earnings and determine whether plan features need to be modified, or whether the IR plan should be abandoned. It is important that the re-opener trigger circumstances be significant enough to prevent re-openers for minor to moderate deviations in earnings as constant re-openers would dampen the benefits if multi-year IR plans. It is also important that the re-opener threshold not be so extreme that the utility has the opportunity to enjoy significant over earnings at customers' expense or that the utility's financial future is placed at risk due to significant earnings shortfalls. Concentric believes that EGD's re-opener trigger of +/- 300 basis points in any year achieves a reasonable balance between allowing the IR plan to continue uninterrupted and providing a safeguard to address unanticipated circumstances. Furthermore, the symmetrical nature of EGD's re-opener trigger provides protection for both customers and EGD.

On balance, we conclude that EGD's proposed ESM provides an appropriate safeguard for customers and the utility. The deadband serves the purpose of incenting EGD to identify additional efficiencies, while the earnings sharing and re-opener trigger provide a safety mechanism to address large deviations in earnings. While we could argue that a 100 basis point deadband creates a diminished incentive compared to a wider deadband, and that a symmetrical ESM would better balance the risk and reward profiles of EGD and customers, EGD's performance under the 1st Generation IR (with the same ESM parameters) suggests that these issues are manageable, as customers benefited from earnings sharing in all 5 years of the Plan. Based on our research and industry experience, Concentric believes that EGD's ESM proposal is reasonable.

IX. EVALUATION OF EGD'S PROPOSED IR PLAN

As discussed in the foregoing report, Concentric has evaluated the proposed Enbridge Customized IR plan based on our regulatory and industry research, quantitative analysis, and knowledge of other programs in North America. We have assessed the proposed plan from two primary perspectives:

- Consistency with Ontario and North American regulatory principles and practice;
- Quantitative assessment of Enbridge's operational efficiency and projected revenue vs. I-X rate paths.

A. Consistency with Regulatory Principles and Practice

The following criteria, as specified in the Company's evidence and taken from the Board's Natural Gas Forum and the Ontario Energy Board Act, present a reasonable set of standards by which to judge the proposed plan. Specifically, does the plan:

a) Ensure appropriate reliability and quality of service (including safe operations);

b) Protect customers from unreasonable price impacts;

c) Promote energy conservation and efficiency;

d) Protect the financial viability of the distributor and allow for appropriate investments to be made; and

e) Provide a framework that incents the distributor to implement sustainable efficiency improvements?

On these points, reliability and quality of service are protected through adequate funding of both O&M and capital budgets, and through service quality monitoring over the course of the plan. Customers are protected from unreasonable price impacts through "testing" the existing cost structure of Enbridge against industry peers, and the projected rate path against that for an industry peer group based on the combination of benchmarking and productivity studies. Conservation and energy efficiency are promoted through ongoing funding of DSM programs. The financial viability of the Company is not guaranteed, but placed in the hands of management who must operate within the "fixed" revenue structure in order to fully recover costs and earn the allowed return. Capital plans are scrutinized in this hearing process, and in Leave to Construct proceedings on major projects. Efficiency improvements are incentivized through (1) a revenue path based on Enbridge's peers, (2) an earnings sharing mechanism, and (3) a sustainable efficiency incentive mechanism.[79] In principle and in design, the overall plan proposed by Enbridge addresses these standards.

Moving beyond Ontario specific standards, we also find the proposal consistent with trends we see elsewhere, where regulators have turned to more flexible models of incentive regulation designed around specific utility circumstances. This plan follows a similar evolution for Enbridge, while still testing the plan against the more formulaic I-X approach.

B. Quantitative Evaluation

To test the reasonableness of EGD's Allowed Revenue amounts, Concentric performed several related evaluations. Concentric compared EGD's forecast O&M cost per customer to EGD's historical trend of O&M costs per customer. EGD's projected O&M cost per customer is higher than recent history, but not by a significant amount. Concentric also compared EGD's forecasted O&M cost per customer with the O&M cost per customer that would be derived from an I-X formula. The results of Concentric's analyses indicate that EGD's projected O&M costs are reasonable based on a comparison to the benchmark utilities, and in relation to the industry analysis of O&M productivity.

Concentric expanded the analysis to consider capital. The quantitative analysis for Concentric's assessment of EGD's proposed capital cost recovery approach is based on the results of models that Concentric developed to determine the capital-related revenue requirements and revenues under alternative rate recovery mechanisms. It is Concentric's assessment that an I-X escalation formula does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $141.5 million. An I-X escalation formula combined with an ICM-type mechanism also does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $88.2 million. Further, an I-X escalation formula combined with Y Factor Recovery of the GTA and Ottawa projects does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $51.2 million. Only Rate Option 4, a Customized IR plan with recovery of capital-related costs matched to EGD's projected capital-related revenue requirements, adequately covers the costs of EGD's base capital spending and GTA and Ottawa reinforcement projects.

These analyses are summarized in the following figures that contrast the total revenue recovered under two alternative rate recovery alternatives (I-X, and I-X plus Y factors for the

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[79] Enbridge's Sustainable Efficiency Incentive Mechanism is described in Exhibit A2, Tab 11, Schedule 3.

GTA and Ottawa projects) versus Enbridge's projected O&M and capital Allowed Revenue amounts. The first figure illustrates the estimated total revenue collected for O&M and capital vs. projected costs on a per customer basis, and the second figure aggregates these into total dollars. The differences between forecasted revenue and the rate recovery mechanism are revenue shortfalls or surpluses. The I-X rate option leads to the largest shortfall, of $126 million; the I-X plus Y factor option produces a lower deficiency, of $35.7 million, but is still inadequate to provide full cost recovery, even with embedded efficiencies.

Figure 38: O&M Plus Capital Cost/Customer

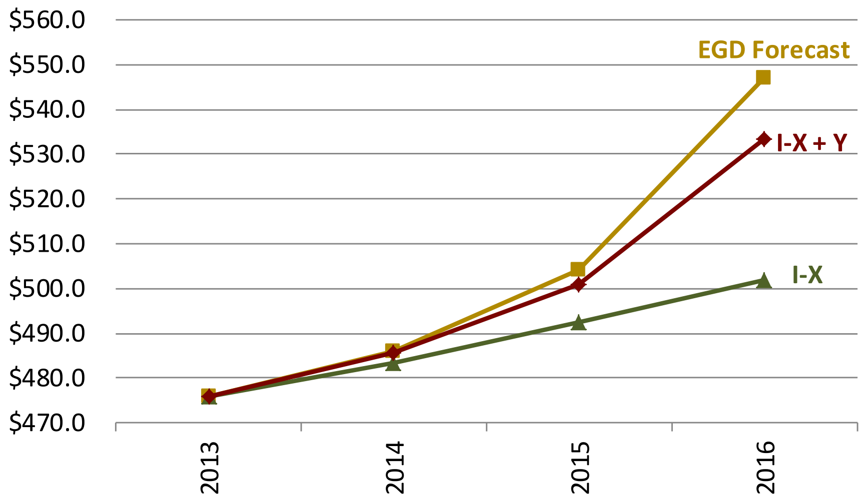
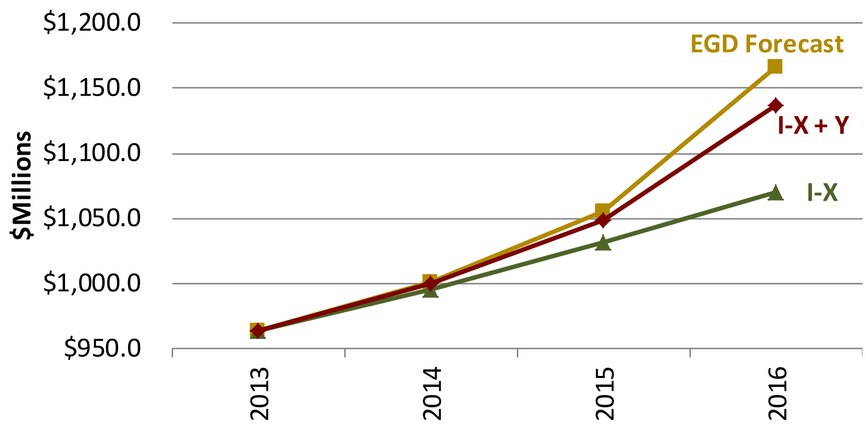


Figure 39: O&M Plus Capital Cost



C. Conclusion

Based on our analysis, research and industry experience, Concentric believes that EGD's overall proposed Customized IR proposal is reasonable. The proposed Customized IR approach is the only mechanism evaluated that tracks costs (including the larger than normal capital investment), while providing Enbridge with a built-in challenge for continued productivity improvement. On balance, we conclude that EGD's proposed plan provides an appropriate safeguard for customers and the utility, and meets to Board's goals for incentive regulation while allowing the company a reasonable opportunity to earn a fair return.

APPENDIX A: BENCHMARKING - 2011 UPDATE

I. INTRODUCTION

Enbridge Gas Distribution ("Enbridge", "EGD", or the "Company") retained Concentric Energy Advisors, Inc. ("Concentric") in 2011 to provide a perspective on Enbridge's performance relative to its peers during the 1st Generation Incentive Regulation ("IR") plan period. That benchmarking analysis measured EGD against both a US and Canadian peer group for the years 2009 and 2010 using a series of metrics designed to examine the relative efficiency of the Company in terms of both its capital investment and O&M expense profile. The benchmarking study also included trend analyses covering the 2000 to 2010 period. The benchmarking study was submitted in EGD's rebasing case, EB-2011-0354, Exhibit A2, Tab 1, schedule 2.

This current study is an update to the original filed benchmarking study. This update relies on the same methodology, data sources, and U.S. peer group as the original benchmarking study, but now incorporates 2011 data.[80] To review, the 28 company industry peer group was based on U.S. companies that have similar operations (i.e., natural gas utilities), similar weather (i.e., in the northern half of the U.S.), and similar size (i.e., at least 500,000 customers) as EGD. Canadian companies were included in the original benchmarking analysis for 2009; however, due to the difficulty obtaining consistent, reliable data Canadian companies were not included in the 2011 update.

Data for EGD was provided by the Company. Data for the U.S. peer group was primarily compiled from annual reports filed by the individual local distribution companies ("LDCs") with their state regulatory commissions ("Annual LDC Reports").

II. INDUSTRY BENCHMARKING RESULTS

A. Peer Group Analysis

Enbridge's performance is compared to a peer group of 28 U.S. natural gas utilities that were chosen for the original analysis based on a number of selection criteria designed to reflect Enbridge's operating profile and provide a broad perspective for industry comparisons. In order to provide proper context and background on the peer group, the following sections compare Enbridge's operational profile in 2011 to the U.S. peer group.

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[80] During the update to include 2011 data, a few historical data points were revised based on additional information becoming available. These revisions did not change the results in any meaningful way.

1. Customer Profile

In terms of utility size as measured by the number of customers, Enbridge is the third largest overall in the peer group. Figures A-1 and A-2 show the total natural gas customers and percentage residential customers in 2011 for Enbridge and each of the natural gas utilities in the U.S. peer group. As shown in the graphs, Enbridge serves almost 2 million customers, with residential customers representing over 90% of Enbridge's customer count.

Figure A-1: Total 2011 Natural Gas Customers
(Sales & Transportation, excludes Resale Customers)

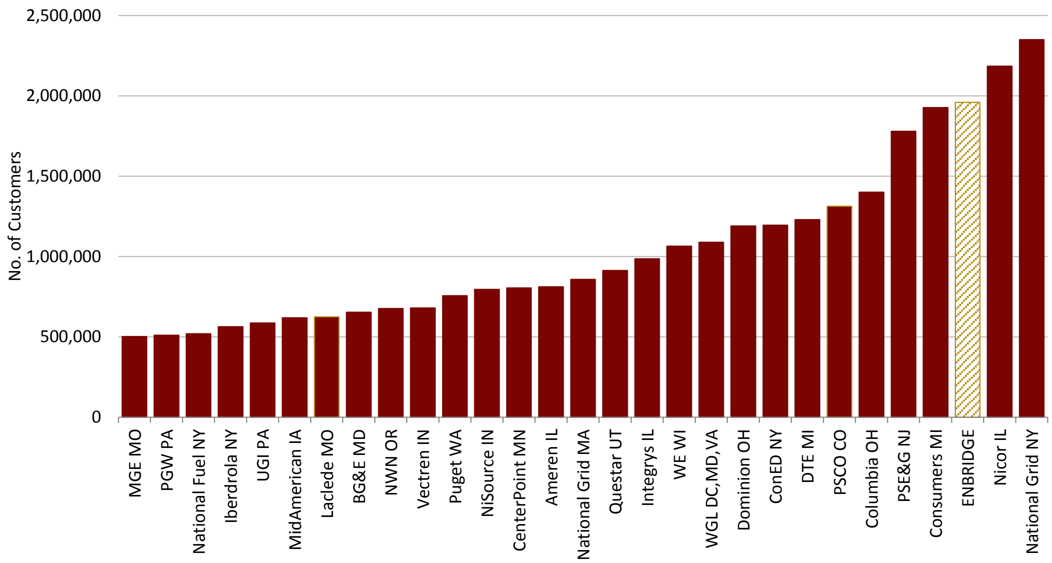
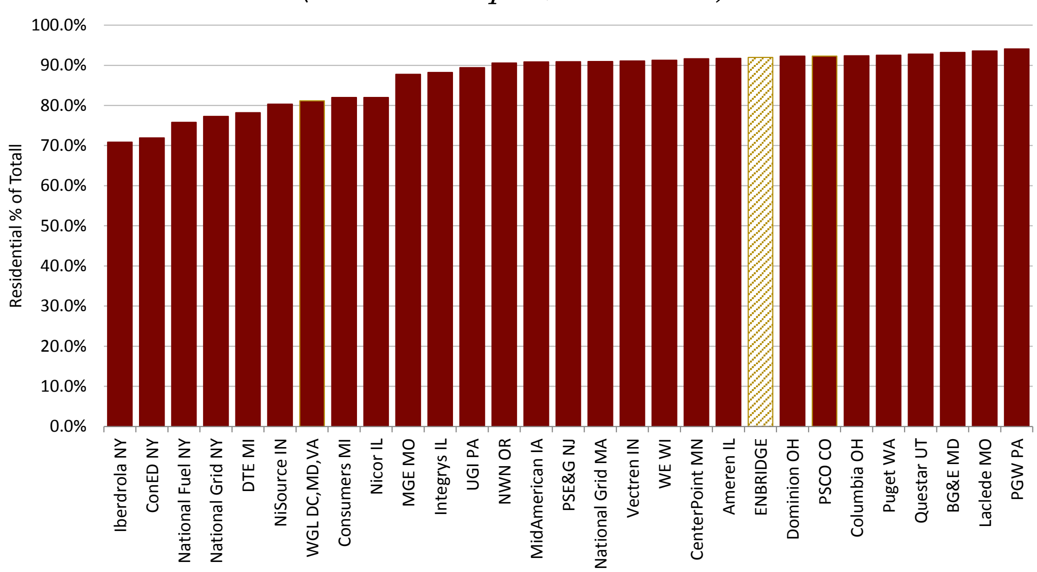


Figure A-2: 2011 Residential Customers as % of Total Natural Gas Customers
(Sales & Transport, excl. Resale)



2. *System Throughput*

Figures A-3 and A-4 show the total natural gas volumes and percentage residential volumes in 2011 for Enbridge and each of the natural gas utilities in the peer group. As illustrated, Enbridge is the third largest utility compared to the U.S. peer group based on total natural gas volumes. Although Enbridge's customer profile is predominantly residential, in terms of its system throughput, residential volumes represent less than 40% of Enbridge's total natural gas volumes, which is in the second lowest quartile in 2011. As shown in Figure A-5, Enbridge is in the top quartile in terms of natural gas volumes per customer.

Figure A-3: Total 2011 Natural Gas Volumes

(Sales & Transportation, excludes Resale Volumes)

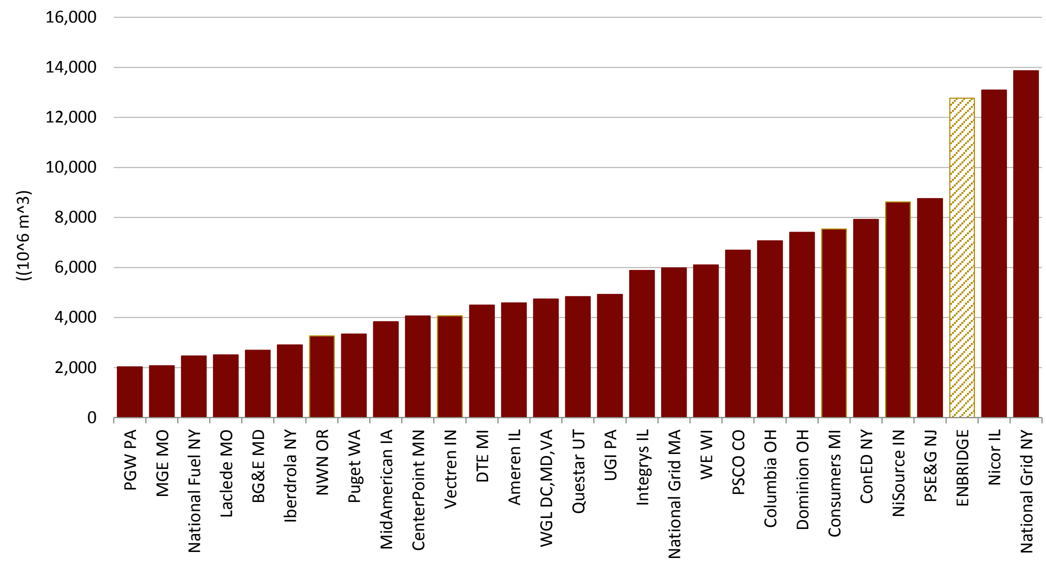


Figure A-4: 2011 Residential Volumes as % of Total Natural Gas Volumes (Sales & Transport, excl. Resale)

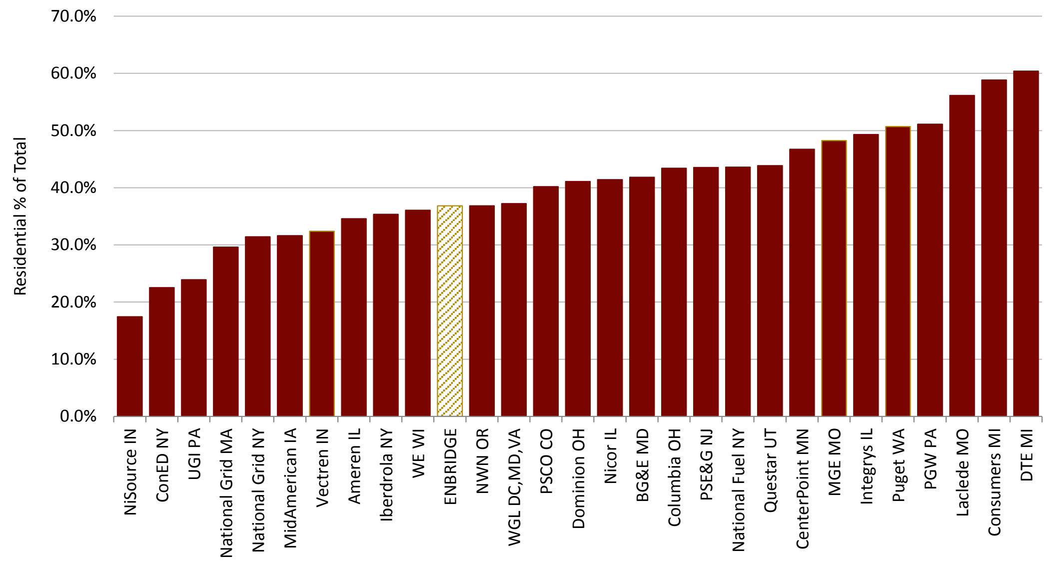
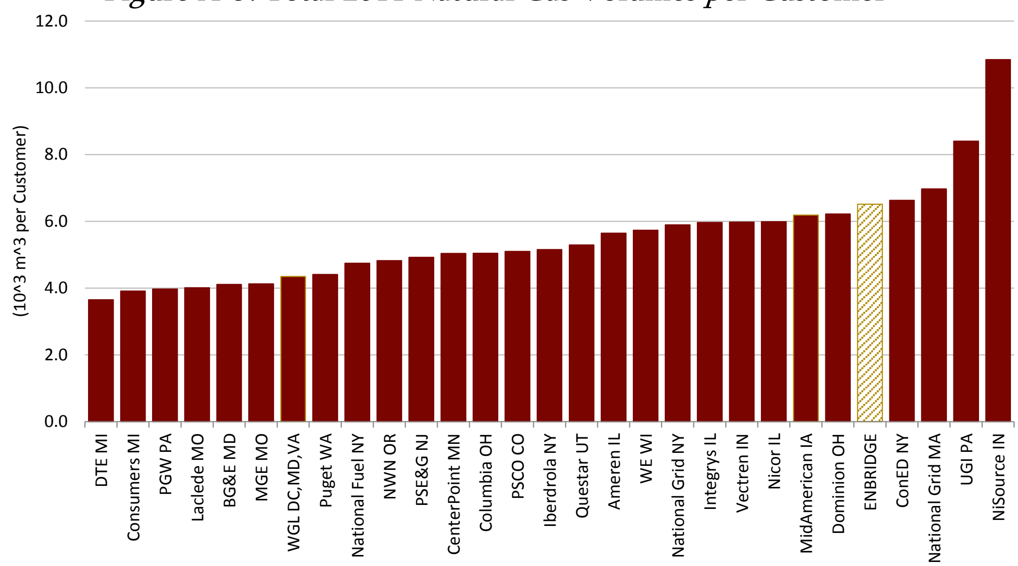


Figure A-5: Total 2011 Natural Gas Volumes per Customer



3. Customer Density

Figures A-6 and A-7 show the customer density (i.e., number of customers per kilometer of distribution main), as well as natural gas volumes per kilometer of distribution main in 2011 for Enbridge and each of the natural gas utilities in the peer group. Enbridge is in the top quartile for density. All else being equal, density is a favorable attribute for the cost of serving gas customers.

Figure A-6: 2011 Natural Gas Customers per Kilometer of Distribution

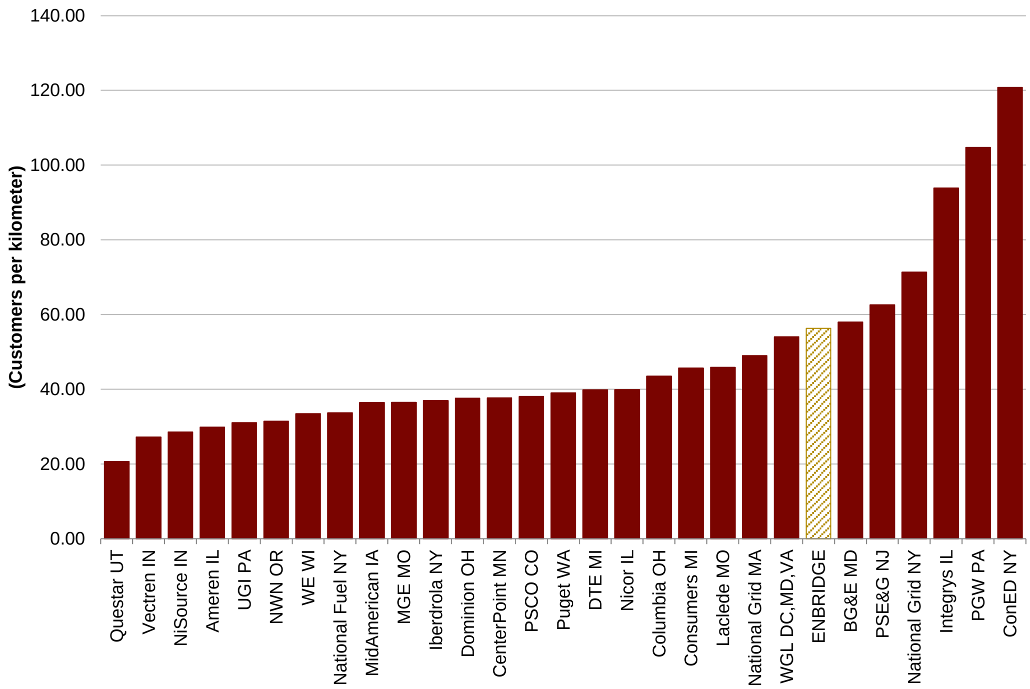
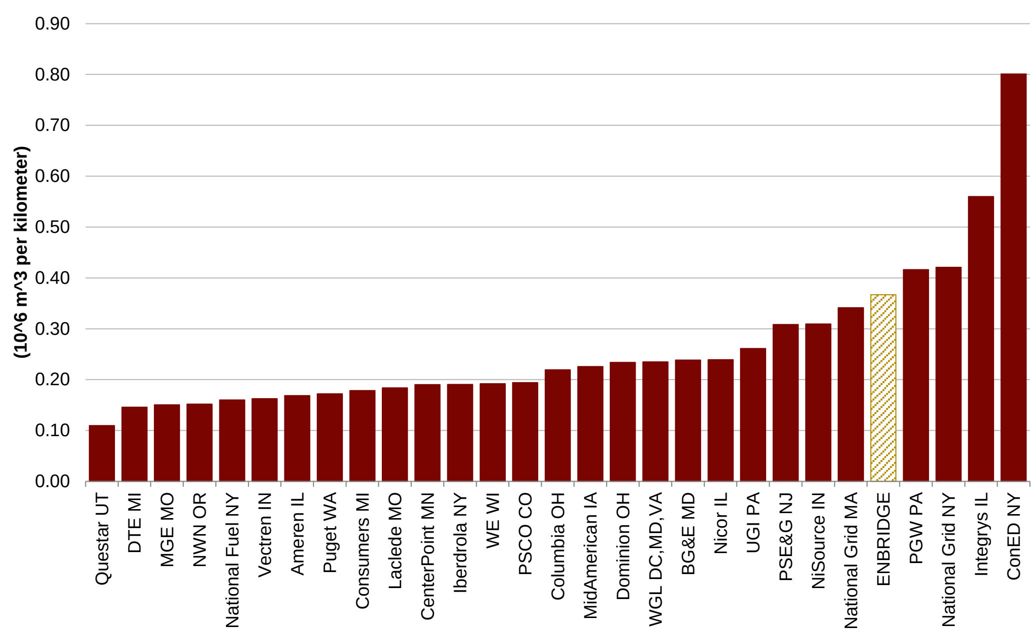


Figure A-7: 2011 Natural Gas Volumes per Kilometer of Distribution Main



Overall, Enbridge is above average in terms of size and density as compared to the peer group, but is within the range of peer group results, indicating that the peer group is appropriate for general benchmarking purposes.

B. Benchmarking and Trend Analysis

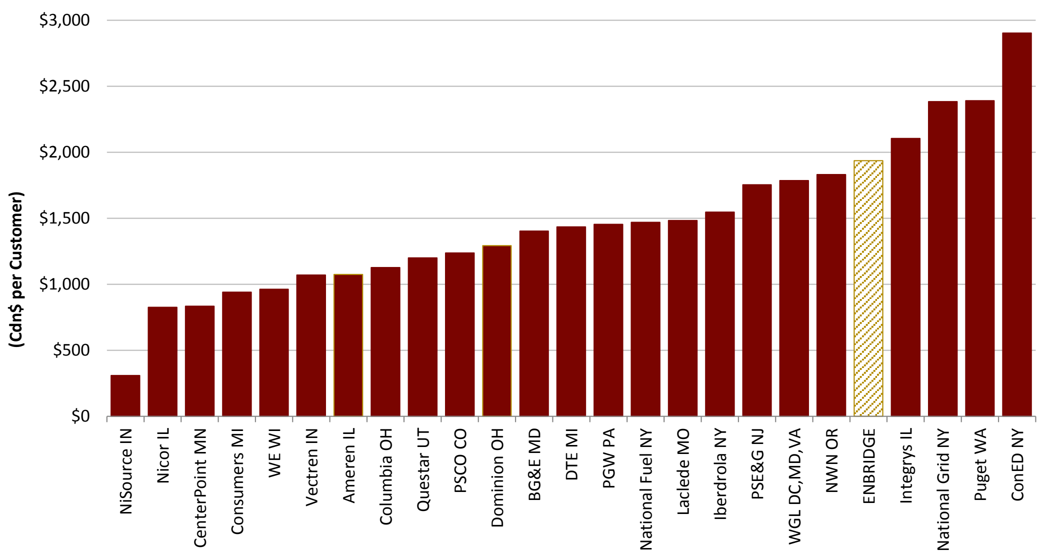
The following sections summarize the results of the benchmarking and trend analysis which compares Enbridge's performance against the peer group across a number of operational metrics. Enbridge's performance in 2011 is benchmarked against the U.S. peer group. In addition, Enbridge's longer-term performance trends are compared to the performance trends of the U.S. peer group over the 2000 to 2011 time period.

1. Net Plant per Customer and per Unit of Volume

The total net plant, as shown in the charts below, includes transmission, storage, distribution, and an allocated portion of general plant costs. Enbridge's total net plant per customer in 2011 is approximately $1,900 per customer. As shown in Figure A-8, Enbridge is in the highest quartile compared to the 28 U.S. natural gas utilities in 2011.

Figure A-8: Total 2011 Net Plant per Customer

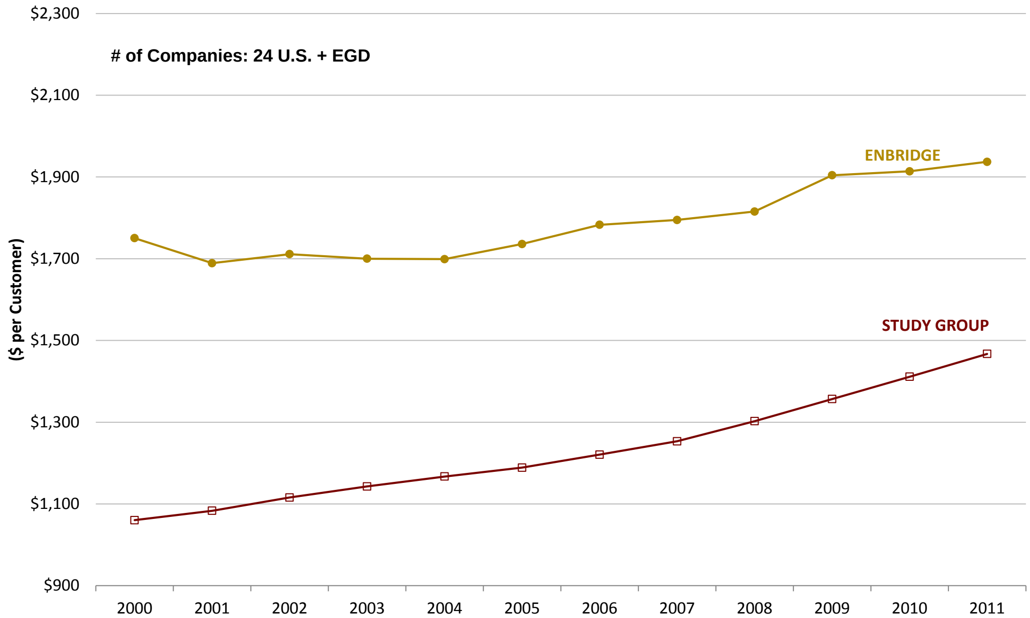
(Includes Transmission, Storage, Distribution and Allocated General Plant)



As illustrated in Figure A-9, both Enbridge and the U.S. peer group have experienced growth in net plant per customer over the 2000 to 2011 time period, but Enbridge's net plant per customer grew at a considerably slower rate than the U.S. peer group.

Figure A-9: Total Net Plant per Customer[81]

(Includes Transmission, Storage, Distribution, and Allocated General Plant)



2. Net Plant per Unit of Volume

As illustrated in Figure A-10, with respect to total net plant per unit of volume, Enbridge falls below the median of the peer group in 2011. As shown in Figure A-11, over the entire time period, both the industry and Enbridge's net plant per unit of volume generally increased, although Enbridge's rate of growth has slowed by comparison to the study group in recent years.

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81 The line charts, which compare costs over the entire 2000 to 2011 period, are expressed in own-country US and Canadian dollars for both the study group and Enbridge, which avoids issues associated with year-to-year exchange rate differences.

Figure A-10: Total 2011 Net Plant per Volume
(Includes Transmission, Storage, Distribution and Allocated General Plant)

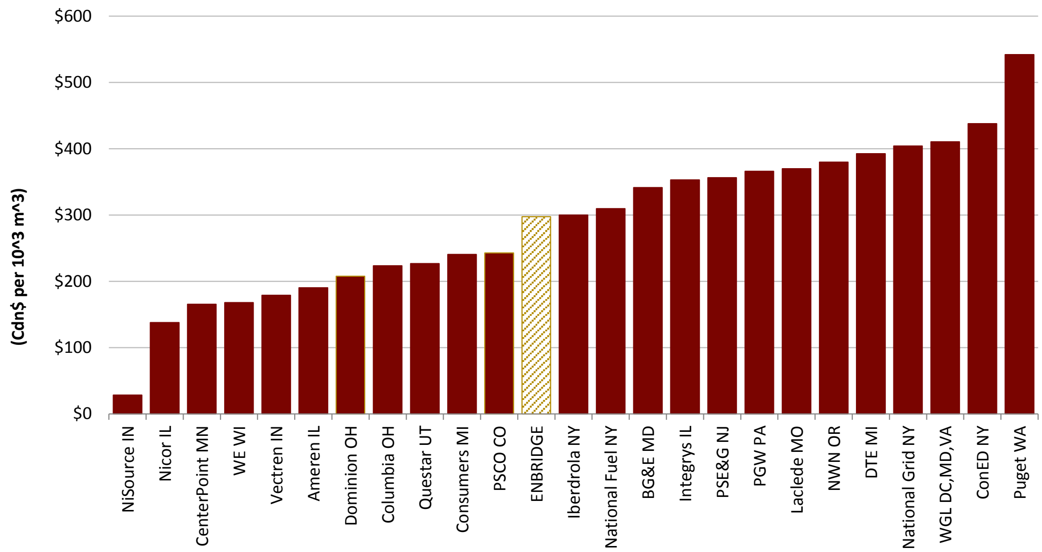
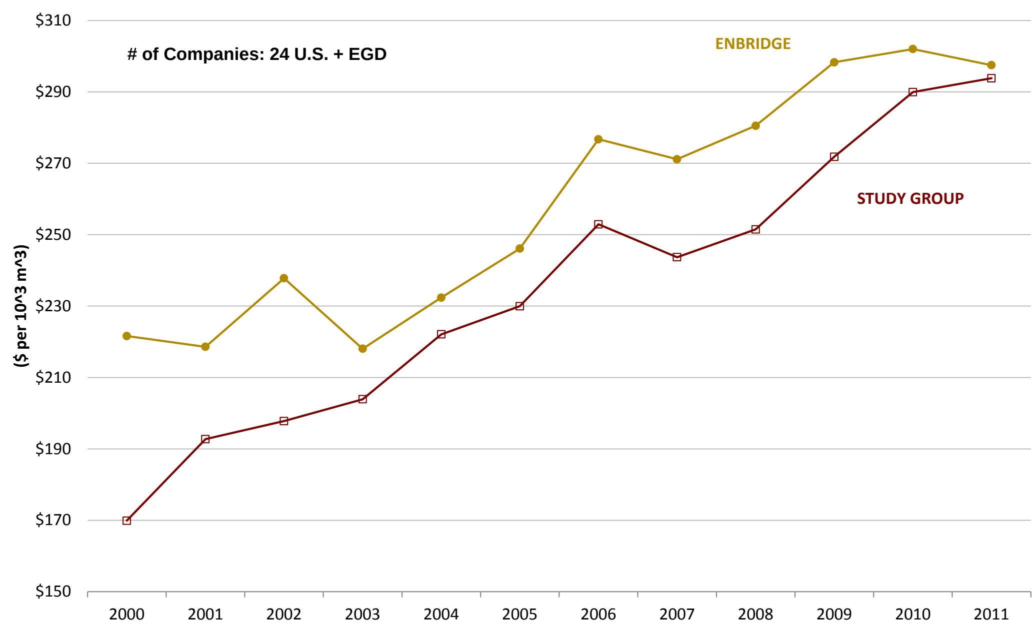


Figure A-11: Total Net Plant per Volume
(Includes Transmission, Storage, Distribution, and Allocated General Plant)

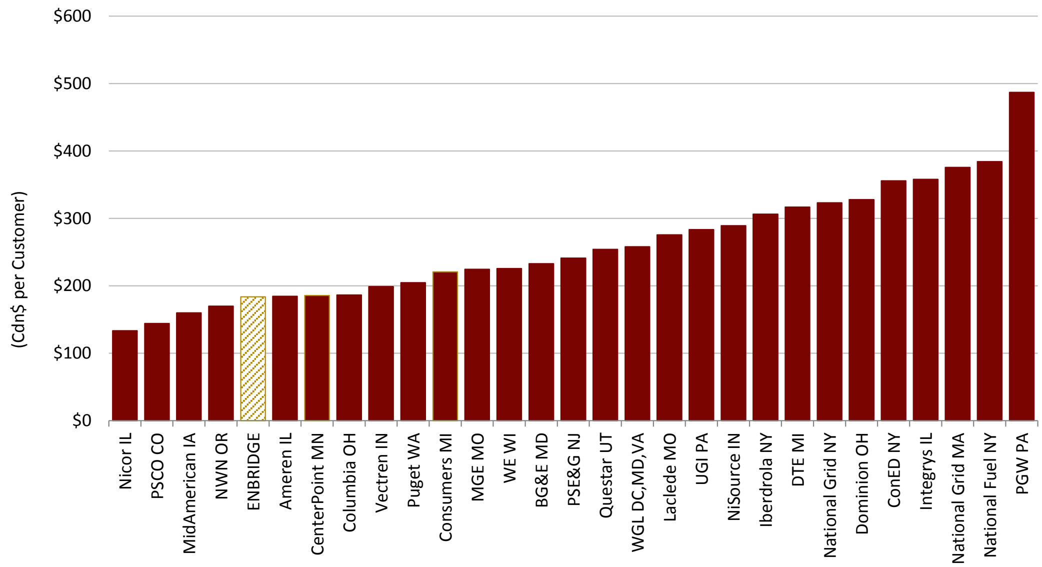


3. Gas O&M Expenses per Customer

As shown in Figure A-12, Enbridge was in the lowest quartile in terms of gas O&M expense per customer.

Figure A-12: Total 2011 Gas O&M Expenses per Customer

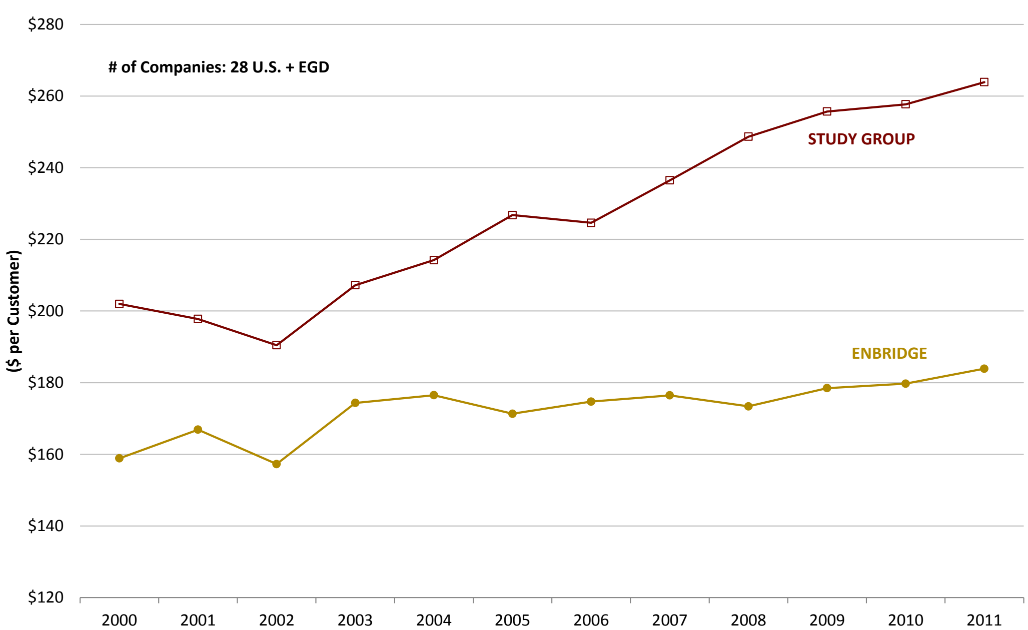
(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)



Over the 2003 to 2011 time period, Enbridge's O&M expense per customer metric increased modestly with an average of approximately $177 per customer, whereas the U.S. peer group average has grown steadily since 2002.

Figure A-13: Total Gas O&M Expenses per Customer

(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)

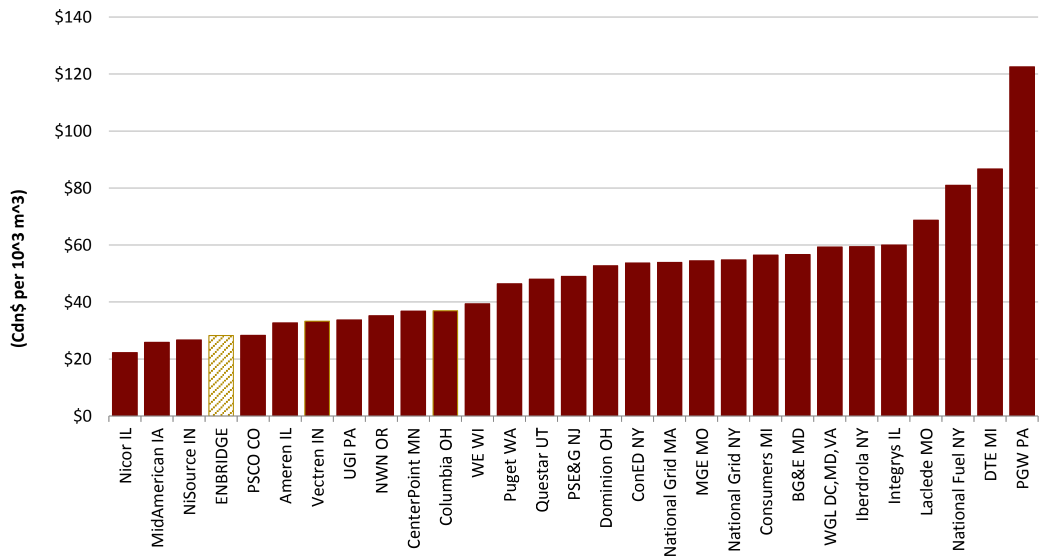


4. Gas O&M Expenses per Unit of Volume

Figure A-14 depicts the total 2011 gas O&M expenses per volume metric for each utility. As shown, Enbridge had the fourth lowest gas O&M expense per volume metric overall. The total gas O&M expense includes transmission, storage, distribution, customer-related, sales and A&G expenses.

Figure A-14: Total 2011 Gas O&M Expenses per Volume

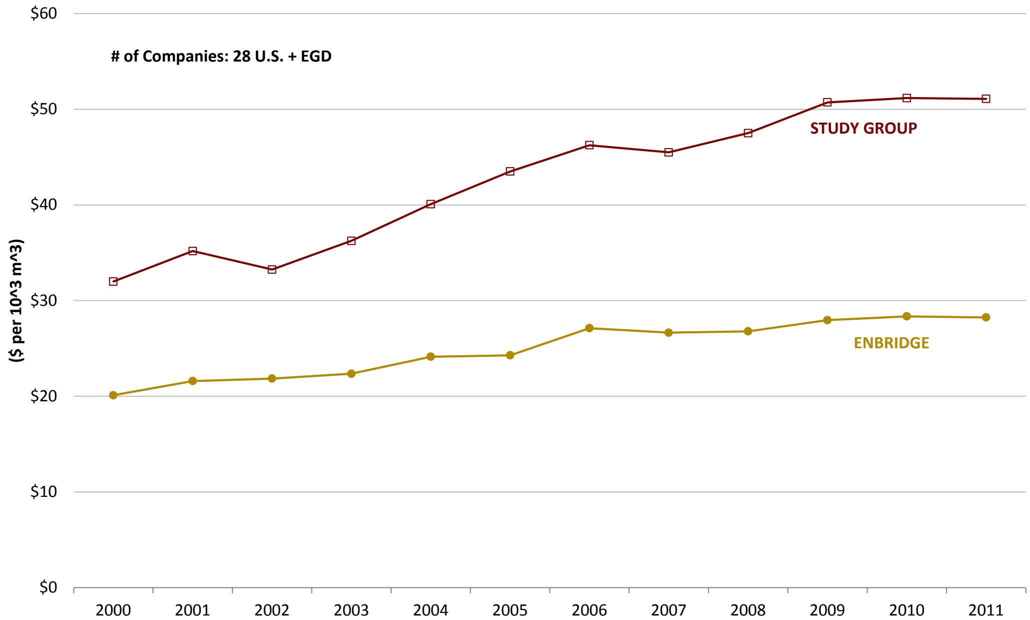
(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)



As illustrated by Figure A-15, both Enbridge and the U.S. peer group have experienced an upward trend in the gas O&M expense per volume metric over the 2000 to 2011 time period, although the increase has been greater for the U.S. peer group. The general decline in volume/customer is partly responsible for this overall trend.

Figure A-15: Total Gas O&M Expenses per Volume

(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)

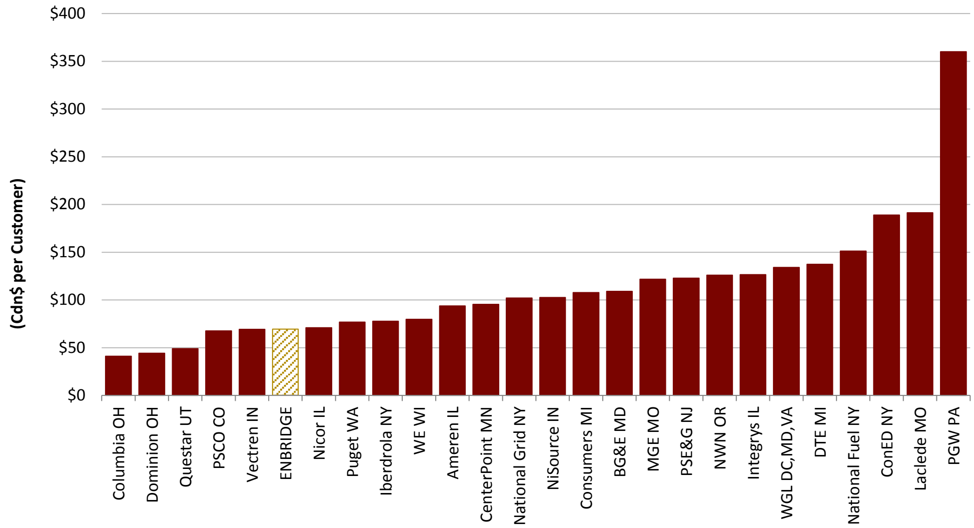


5. Labour Costs per Customer[82]

Figures A-16 and A-17 show the total labour costs per customer for 2011, both excluding and including capitalized amounts, for Enbridge and each of the natural gas utilities in the peer group. In terms of labour costs, Enbridge was in the lowest quartile for labour costs per customer compared to the peer group overall.

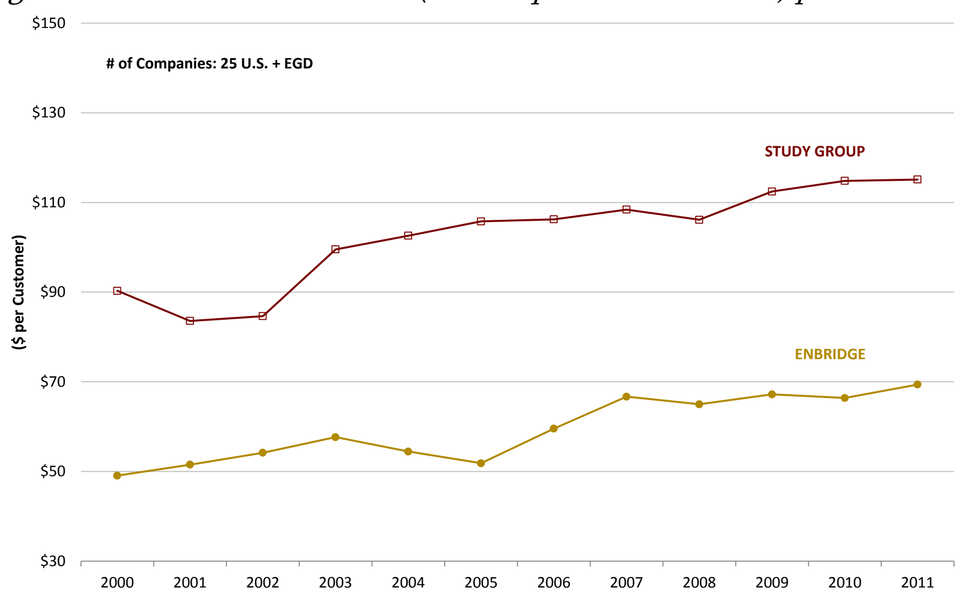
[82] During the update to include 2011 data, a few historical data points were revised based on additional information becoming available. These revisions did not change the results in any meaningful way.

Figure A-16: Total 2011 Labour Costs (excl. Capitalized Amounts) per Customer



While both Enbridge and the U.S. peer group's labour costs (excluding capitalized amounts) per customer have trended upward, Enbridge's labour costs (excluding capitalized amounts) per customer flattened out over the 2007 to 2011 time period.

Figure A-17: Total Labour Costs (excl. Capitalized Amounts) per Customer



As shown in Figures A-18 and A-19, when including capitalized costs in the labour costs per customer metric, Enbridge ranks in the second lowest quartile in 2011. Both Enbridge and the U.S. peer group have experienced an increase in labour costs per customer over the 2000 to 2011 time period (including capitalized amounts).

Figure A-18: Total 2011 Labour Costs (incl. Capitalized Amounts) per Customer

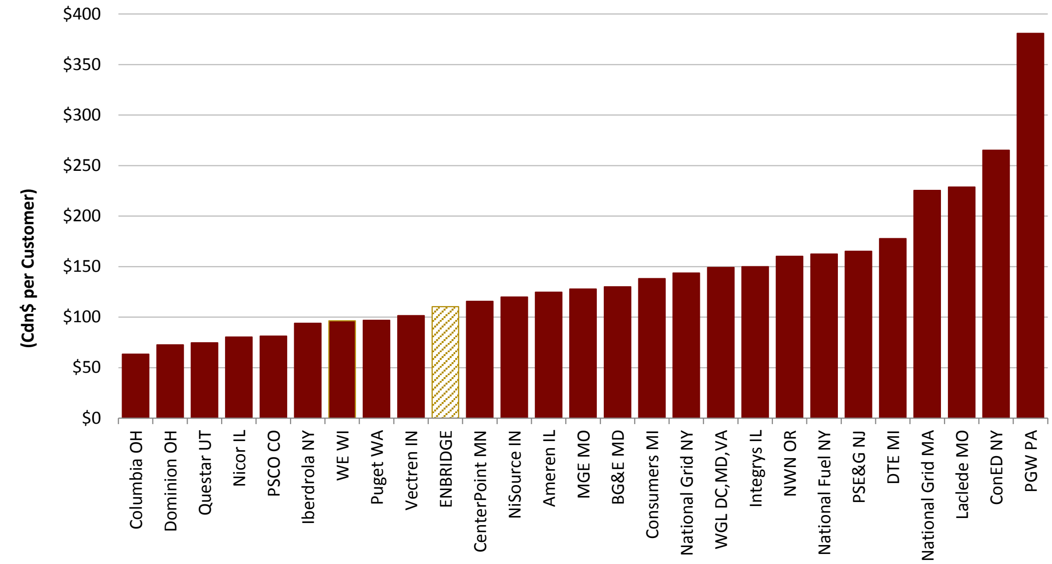
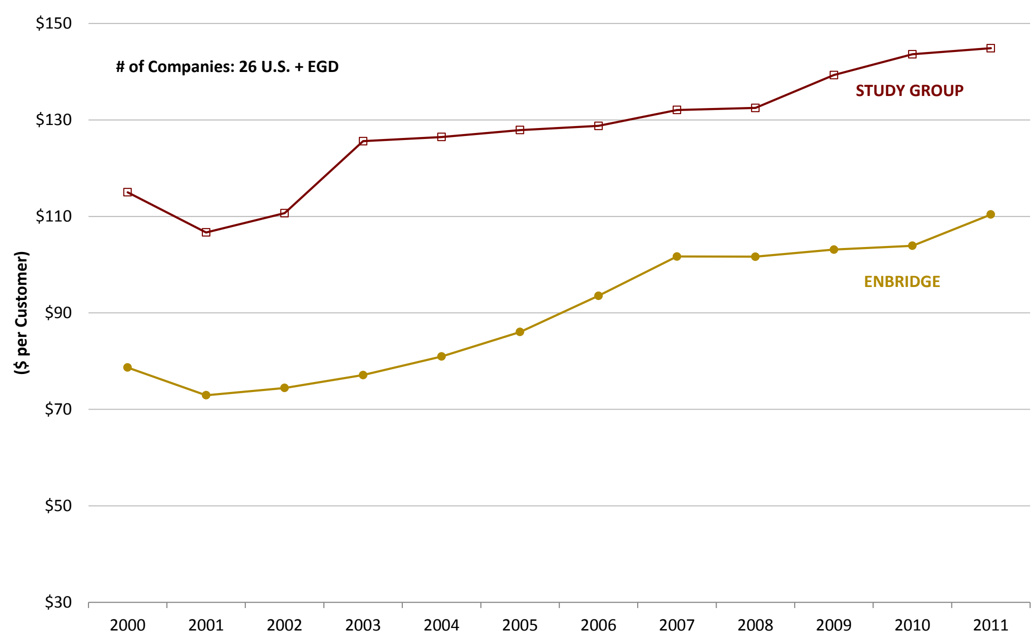


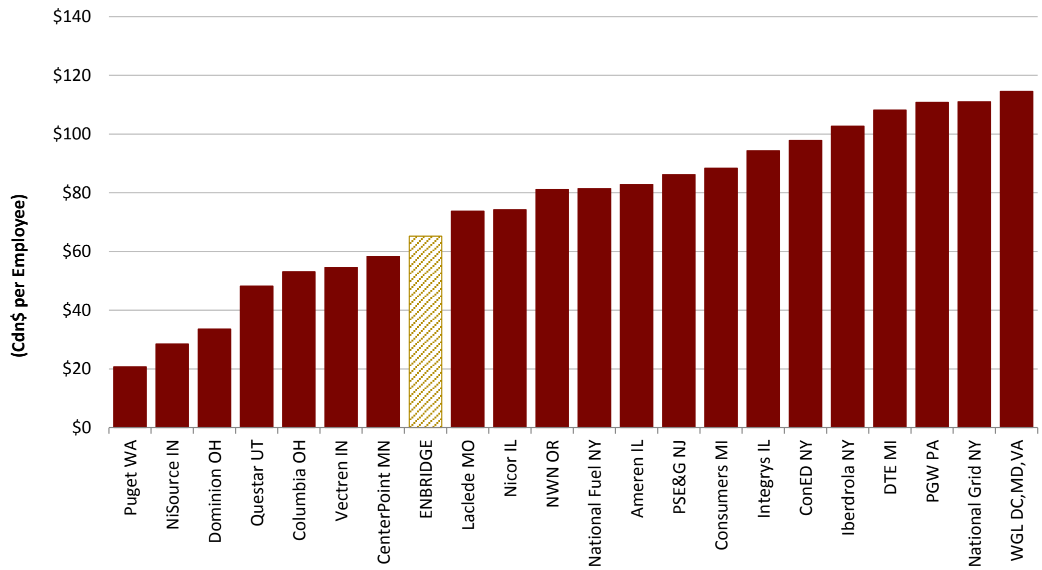
Figure A-19: Total Labour (incl. Capitalized Amounts) per Customer



6. *Labour Costs per Employee*[83]

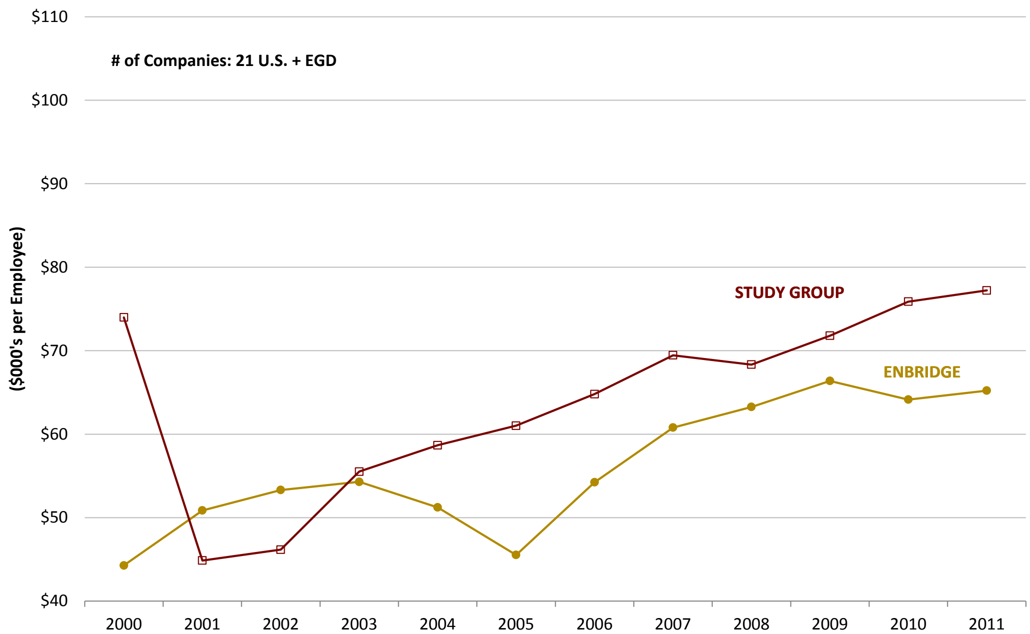
In terms of labour costs per employee, Enbridge's labour cost of approximately $65,000 per employee is lower than the average across the peer group, and ranks eighth overall as illustrated in Figure A-20. Figure A-21 demonstrates that labour costs per employee for both EGD and the U.S. peer group trended upward between 2005 and 2009. In 2010 and 2011, the U.S. peer group continued the upward trend; however, Enbridge experienced a decrease in labour costs per employee.

Figure A-20: Total 2011 Labour Costs (excl. Capitalized Amounts) per Employee



83 During the update to include 2011 data, a few historical data points were revised based on additional information becoming available. These revisions did not change the results in any meaningful way.

Figure A-21: Total Labour Costs (excl. Capitalized Amounts) per Employee



When including capitalized costs in the labour costs per employee metric, Enbridge ranks near the median of the peer group in 2011, as illustrated in Figure A-22. Figure A-23 demonstrates that over the 2001 to 2011 time period, both Enbridge and the U.S. peer group of 22 utilities have experienced steady increases in labour costs per employee (including capitalized labour).

Figure A-22: Total 2011 Labour Costs (incl. Capitalized Amounts) per Employee

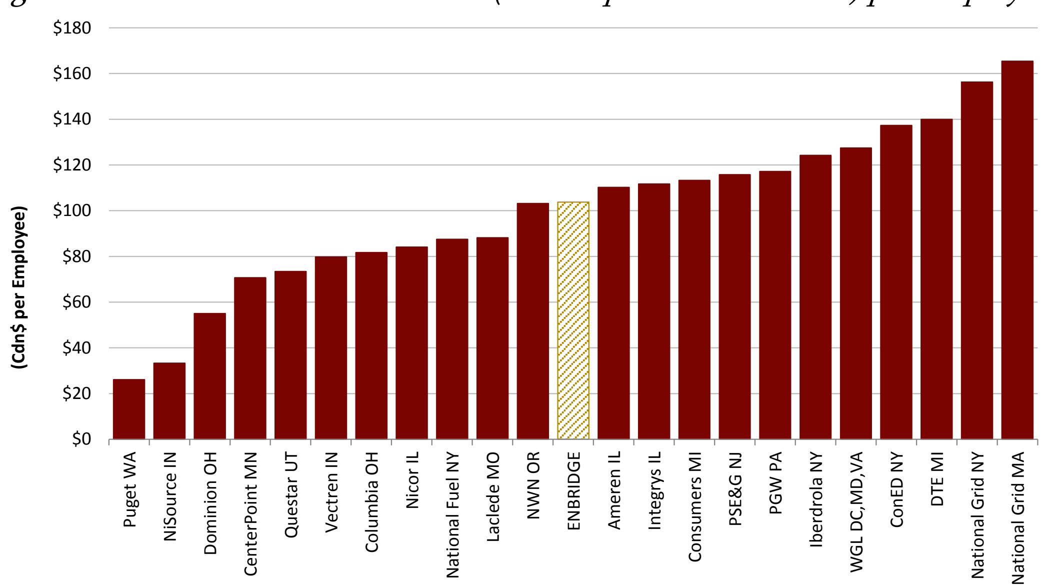
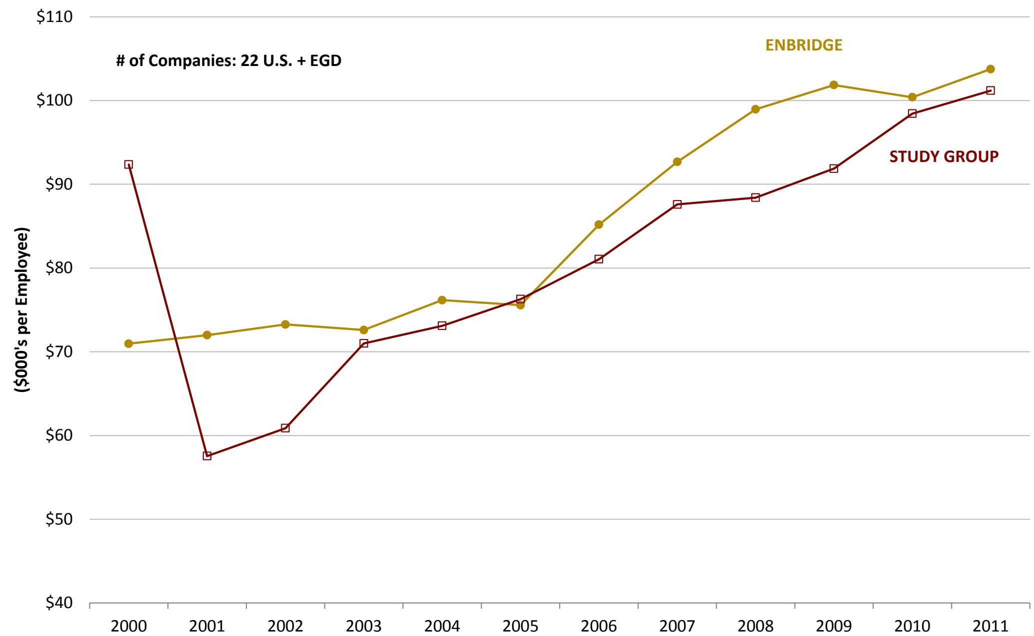


Figure A-23: Total Labour Costs (incl. Capitalized Amounts) per Employee



7. *Customers per Employee*

Figures A-24 and A-25 depict the total natural gas customers per employee; Enbridge has the sixth highest level of customers per employee in 2011. Over the 2000 to 2011 time period, Enbridge has maintained a high level of natural gas customers per employee as compared to the U.S. peer group average.

Figure A-24: Total 2011 Natural Gas Customers per Employee

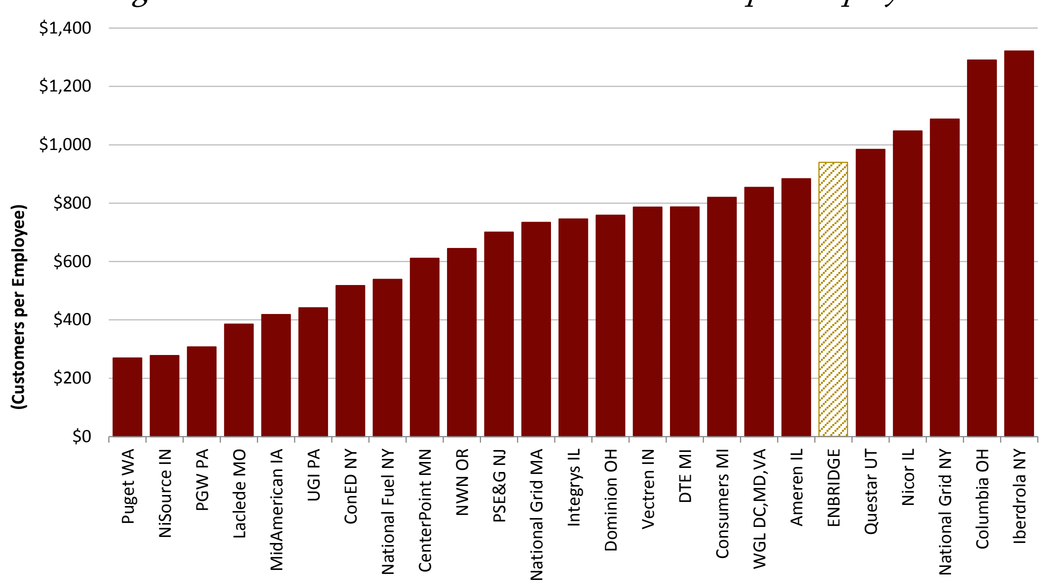
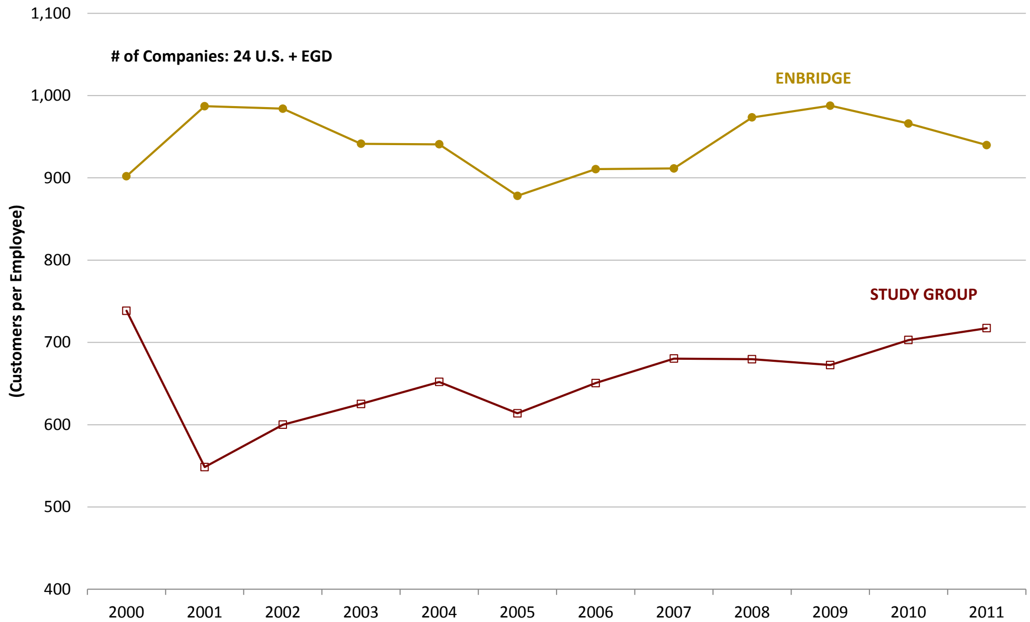


Figure A-25: Total Natural Gas Customers per Employee



III. CONCLUSIONS

The benchmarking analysis contrasts Enbridge with a group of 28 U.S. natural gas utilities. The benchmarking analysis in aggregate indicates that Enbridge is among the most efficient of its U.S. peers.

In terms of comparative size and composition of the Company's service area:

- Enbridge has the 3rd highest customer count and 3rd highest throughput as compared to the U.S. utilities in the peer group, suggesting the potential for scale economies.
- The Company's customer count is, however, also 92% residential.
- Reflecting this customer profile, the Company ranks 5th highest in terms of average gas volume per customer in 2011.
- Reflecting the relatively urban nature of EGD's service area, the Company ranks 7th highest in terms of customers per mile of distribution main and 5th highest in term of volumes per mile of distribution main.

In terms of comparative metrics for capital, operating and maintenance costs:

- The Company ranks 5th highest in terms of overall net plant invested per customer in 2011. Net plant invested per customer has risen over the past decade for both EGD and the US peer group.
- Expressed on a volumetric basis, Enbridge ranks in the middle of all companies on a net plant per unit of system throughput. Due to declining use per customer, net invested plant per unit of throughput has risen more sharply for both EGD and the US peer group over the past decade, however Enbridge slightly decreased in 2011.
- O&M costs per customer for Enbridge are the 5th lowest overall in 2011. These costs have risen more slowly for EGD than for the peer group over the decade, and have remained relatively level for EGD during the 2007 to 2011 IR period measured.
- Expressed on a volumetric basis, Enbridge's O&M costs rank 4th lowest overall. EGD's O&M costs per unit of throughput have risen more slowly than the US peer group's over the past decade.
- Labour costs for Enbridge place the Company at 6th lowest overall in 2011 on a per customer basis excluding capitalized costs and 10th lowest in 2011 including capitalized costs. Enbridge's non-capitalized labour costs have risen more slowly than the US peer group in recent years.
- Expressed on a per employee basis, Enbridge's labour costs ranked 8th lowest overall excluding capitalized costs in 2011, and near the median including capitalized costs.

- When considering customers served by utility workforce, Enbridge ranked 6th highest in 2011. EGD has steadily outperformed its US peer group over the decade, although the gap has narrowed in recent years.

One would expect a utility of Enbridge's size and scale to be among the most efficient of its peers, even though its urban service area, residential customer concentration, and declining use per customer present cost challenges. One could argue that National Grid NY is most like Enbridge, with over 2 million customers and a relatively high customer concentration per kilometer of main, yet Enbridge ranks 5th lowest overall in O&M expenses per customer in 2011 while National Grid NY ranks 23rd, and in 2010, Enbridge ranked 6th lowest, while National Grid NY ranked 22nd. More consistent with expectations, the second largest company in terms of customers, Northern Illinois Gas, is also the most efficient in terms of O&M costs per customer, just ahead of Enbridge which ranks 3rd highest in customers and 5th lowest in O&M costs per customer.

On balance, the benchmarking analysis indicates that Enbridge is among the most efficient of its U.S. peers in most categories measured. The exceptions are net plant per customer, net plant per unit of volume, and labour costs (including capitalized labour) per employee, where the Company is closer to or above the average. Examining trends over the 2000 – 2011 period measured, Enbridge has generally sustained or improved its position in relation to its peers, including during the most recent IR plan period.

APPENDIX B: PRODUCTIVITY ANALYSIS DATA SOURCES AND METHODOLOGY

I. PRODUCTIVITY ANALYSIS DATA SOURCES

Concentric's analysis of EGD's productivity is primarily based on data provided by EGD for the years 2000 through 2011. Data provided by the Company includes historical expenses, plant, customer count, throughput, rate of return, and weather data. The industry productivity analysis is based on data compiled from publicly available sources and commercially available databases for the U.S. natural gas utilities included in the industry study group. Although the industry productivity analysis is primarily based on data from 2000 to 2011, some data were collected for other periods of time.[84] For the industry productivity analysis, necessary data is available for 1999 to 2011; for EGD, the necessary data is available for 2000 to 2011. Concentric used data from 2000 to 2011, consistent with the goal of using the most recent 10-15 years of data to calculate productivity.

Company-specific data for U.S. natural gas utilities was largely compiled from annual reports filed by the individual local distribution companies ("LDCs") with their state regulatory commissions ("Annual LDC Reports"),[85] and the Annual Reports of Natural and Supplemental Gas Supply and Disposition ("Form EIA-176")[86] filed with the U.S. Energy Information Administration ("EIA"). These sources were used to compile a U.S. natural gas utility database, which was used to conduct the productivity analysis for the industry study group.

The database was checked for completeness, accuracy, and consistency. Data was gathered at the individual operating subsidiary level; data for a number of different individual operating subsidiaries were combined to account for mergers and acquisitions in order to develop complete, consistent data series (e.g., companies that now comprise National Grid (NY) include (1) KeySpan Energy Delivery (a.k.a. KED-NY, formerly Brooklyn Union), (2) KeySpan Gas East (a.k.a. KED-LI, formerly Long Island Lighting Company), and (3) Niagara Mohawk Power Corporation). In addition, data for separate operating subsidiaries of the

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84 For example, plant in service and additions to plant data starting in 1995 was used to develop the capital quantity input index.

85 Concentric primarily relied on data from the Annual LDC Reports as provided through the SNLxL database.

86 Company-specific data from Form EIA-176 was compiled primarily from the SNLxL database of the SNL Financial website and supplemented by data from the EIA-176 query system.

same parent company within a single state were aggregated at the state level.[87] Finally, gaps in data (i.e., missing data) and data inconsistencies were identified by examining line graphs for each data series for each company. The following sections provide a detailed discussion of the data utilized in the Input Index and the Output Index calculations for the industry study group.

A. Input Index Data

The following U.S. natural gas utility cost data was used to develop the Input Index for the industry study group:[88]

- Labour
  - Gas Salaries and Wages – O&M (i.e., excluding capitalized amounts) for 1999-2011
  - Administrative and General ("A&G") – Employee Pensions and Benefits for 1999-2011
- Materials
  - O&M Expenses (including Distribution, Transmission, Storage, Customer Accounts, Customer Service, Sales, and A&G) for 1999-2011
- Capital
  - Gas Plant In Service (including Distribution, Transmission, Storage, LNG Processing, and General) for 1995
  - Accumulated Depreciation (including Distribution, Transmission, Storage, LNG Processing, and General) for 1995
  - Gas Plant Additions, by Major Category (including Distribution, Transmission, Storage, LNG Processing, and General) for 1996-2011

For the Input Index, Concentric primarily relied on data compiled at the operating subsidiary level from the annual reports filed by the individual LDCs with their respective state regulatory commissions ("Annual LDC Reports") as provided through the SNLxL database

[87] For example, data for the gas operations of Con Edison of New York and Orange & Rockland Utilities, which are operating subsidiaries in the state of New York of Consolidated Edison, Inc., were combined.

[88] In all cases gas costs were excluded as they are largely outside of the utility's control and tend to be a pass through item. Ideally other costs that are largely outside of the utility's control (e.g., energy efficiency/DSM and pensions) would have also been excluded; however, these costs were not consistently reported as separate line items; therefore identification and exclusion of these costs was not possible.

from the SNL Financial website. When data was missing and not available directly through the SNLxL database, Concentric manually entered the data from the Annual LDC Reports, if possible (e.g., gas salaries and wages – O&M data was not available through the SNLxL database for most operating subsidiaries, so this data was manually entered from the Annual LDC Reports).

The missing/inconsistent data points were supplemented by:

- Data from the Uniform Statistical Reports as provided and reported through AGA's electronic Gas Utility Statistics ("eGUS") database, if it was consistent with the data and data trends in the Annual LDC Reports; or
- Calculations based on straight-line trends in the data.

Overall, approximately 1% of the state-level company data used in the Input Index were supplemented by data from the AGA's eGUS database and approximately 2% were based on calculations of straight-line trends. Figure B-1 provides details of the data manipulations by data series utilized in the Input Index for the industry study group.

Figure B-1: Adjustments to Reported Data for Input Index Database for the 25 Company Industry Study Group

	Data Sources	Occurrence of Adjustments	
Data Description	LDC Annual Reports	% from AGA eGUS Database	% Estimated
Labour			
Gas O&M Salaries & Wages	1999-2011	7.1%	2.1%
A&G-Employee Pensions & Benefits	1999-2011	2.6%	1.0%
Materials			
O&M Expenses, by Major Category	1999-2011	0.4%	0.3%
Capital			
Gas Plant In Service, by Major Category	1995-2011	0.1%	1.3%
Gas Plant In Service, by Major Category	1995	0.0%	2.4%
Accumulated Depreciation, by Major Category	1995-2011	6.6%	4.0%
Accumulated Depreciation, by Major Category	1995	10.3%	7.7%
Gas Plant Additions, by Major Category	1996-2011	0.0%	2.7%
TOTAL		1.0%	1.7%

B. Output Index Data

The following U.S. natural gas utility sales data were used to develop the Output Index for the industry study group:[89]

- Customers
  - Sales Customers by Segment for 1999-2011
  - Transportation Customers by Segment for 1999-2011
- Volume[90]
  - Sales Volume by Segment for 1999-2011
  - Transportation Volume by Segment for 1999-2011
- Revenues
  - Operating Revenues by Segment for 1999-2011
  - Production Expenses for 1999-2011

For the Output Index, Concentric primarily relied on data compiled at the operating subsidiary level from the Annual Reports of Natural and Supplemental Gas Supply and Disposition ("Form EIA-176") filed with the U.S. Energy Information Administration ("EIA") as provided through the SNLxL database from the SNL Financial website for customers and volumes. When customer and volume data were not available directly through the SNLxL database, Concentric was able to manually supplement with data from EIA's own Form-176 database. Missing/inconsistent customer and volume data points were supplemented by data from the Annual LDC Reports if they were consistent with data in surrounding years, as reported by EIA Form-176 filings. Overall, approximately 6.6% of the customer and volume data used in the Output Index for the industry study group was supplemented by data from Annual LDC Reports, and approximately 0.3% was estimated using available data.

Revenues and production expenses were compiled from Annual LDC Reports. Missing/inconsistent revenue and production expense data were estimated. Approximately

[89] Data were generally available for the period 1995 to 2011; the Output index is determined with data from 1999 to 2011.

[90] Volume data by segment was used in estimating distribution revenues, which were used to develop output index weights.

0.2% of the Revenue and Expense data was estimated using available data. Figure B-2 provides details of the adjustments and modifications to the data used in the Output Index.

Figure B-2: Adjustments to Reported Data for Output Index Database
For the 25 Company Industry Study Group

Data Description	Data Source	Occurrence of Adjustments	
	EIA-176 Database	% from LDC Annual Reports	% Estimated
Output Index Data			
Sales Customers, by Segment	1999-2011	5.2%	0.5%
Transportation Customers, by Segment	1999-2011	6.8%	0.6%
Sales Volume, by Segment	1999-2011	7.9%	0.0%
Transportation Volume by Segment	1999-2011	7.0%	0.0%
Total Natural Gas Volume	1999-2011	3.5%	0.0%
TOTAL		**6.6%**	**0.3%**

Data Description	Data Source	Occurrence of Adjustments
	LDC Annual Reports	% Estimated
Output Index Data		
Natural Gas Operating Revenue	1999-2011	0.2%
Production Expense	1999-2011	0.2%
TOTAL		**0.2%**

C. Other Data

In addition, authorized industry return on equity ("ROE") and debt-equity ratios were obtained from SNL Financial Regulatory Research Associates ("RRA") for all U.S. gas utilities.

Data on heating degree days ("HDDs") were obtained from the National Climatic Data Center for the U.S. states.

Lastly, data was obtained from other publicly-available or subscription sources, including:

- Bloomberg,
- Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor,
- Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce,
- Statistics Canada ("StatsCan"), and
- Whitman, Requardt & Associates.

II. INPUT INDEX METHODOLOGY

A. Introduction

The company-specific input quantity index measures trends in the quantity of inputs used by each company. The TFP input indexes are an aggregation of labour, materials and capital quantity sub-indexes. Input quantity annual growth rates for each company are determined by weighting the growth rates of each of the input quantity sub-indexes (labour, materials, capital) by the sub-index cost as a percent of total cost, by company and year. The Labour and Materials indexes are derived from distribution-related expense data that is recorded in the following categories of expense accounts: (a) Operations and Maintenance ("O&M")[91] (b) Administrative and General,[92] (c) Customer Accounts, (d) Customer Service and Informational, and (e) Sales. The Capital quantity indexes are derived from distribution-related Utility Plant accounts.[93]

B. Labour

1. Labour Cost

Concentric used salaries and wages expenses, net of capitalized amounts as the annual labour cost for each company. Labour costs associated with capital projects were not included because these costs are captured in the capital index. The labour costs captured in the labour index, therefore, relate to operations and maintenance ("O&M") activities.[94]

2. Labour Price

For the EGD Labour Sub-Index, the Average Hourly Wages for All Employees in Ontario as published by StatsCan[95] was used (a) to determine the labour price index, and (b) to derive Labour Quantity. For each of the companies in the Industry Study Group, the Employment

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91 Including distribution, transmission, and storage O&M accounts

92 Pensions and benefits expenses were excluded from the analysis.

93 Including utility regulated distribution, transmission, storage, LNG processing, and general plant.

94 Throughout this Appendix Concentric uses the term "O&M" to include distribution-related expenses in the categories of (a) Operations and Maintenance (b) Administrative and General, (c) Customer Accounts, (d) Customer Service and Informational, and (e) Sales.

95 Source: Statistics Canada. Table 282-0069 - Labour force survey estimates (LFS), Ontario, All Employees, wages of employees by type of work, National Occupational Classification for Statistics (NOC-S), sex and age group, unadjusted for seasonality; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on November 6, 2012.

Cost Index for Wages and Salaries for Utilities published by BLS[96] was used (a) to determine the labour price index, and (b) in the calculation of Labour Quantity.

3. Labour Quantity

The Labour sub-index measures the trend in Labour Quantity. Concentric calculated EGD's annual Labour Quantity by dividing annual labour cost by the StatsCan Total Compensation Index. The Labour Quantity for each of the industry study group companies was calculated by dividing annual labour cost for that company by the BLS Employment Cost Index for that year.

C. Materials

1. Materials Cost

The materials sub-index measures the trend in all other inputs that are not labour or capital-related. In this report, this category is referred to as "materials". The materials sub-index includes all distribution-related non-labour O&M expenses such as equipment rents, leases, cost of materials, and cost of contractors. Annual materials costs for each company were determined by subtracting salaries and wages expenses identified above, and pensions and benefits expenses from the total O&M expenses (including administrative and general expenses, excluding production-related O&M expenses).

2. Materials Price

For the EGD Materials Sub-Index the Canadian Gross Domestic Product Implicit Price Index, Final Domestic Demand ("GDP-IPI-FDD"),[97] was used for the materials price index. The U.S. Gross Domestic Product Implicit Price Deflator ("GDP-IPD")[98] was used for the materials price index for the industry study group analysis.

3. Materials Quantity

The Materials sub-index measures the trend in Materials Quantity. Concentric calculated the Materials Quantity for each company by dividing annual nominal materials cost for that

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96 Source: BLS, Employment Cost Index Historical Listing, Continuous Occupational and Industry Series, September 1975-September 2012 (December 2005=100), Table 9, October 31, 2012.

97 Source: Statistics Canada, Table 380-0003, Gross domestic product (GDP) indexes, Canada, Implicit price indexes, Final domestic demand, quarterly (2002=100) available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on October 9, 2012.

98 Source: BEA, Table 1.1.9. Annual Implicit Price Deflators for Gross Domestic Product (Index Numbers, 2005=100), last revised September 27, 2012.

company by the annual materials price index. Materials Quantity is equivalent to real non-labour O&M expense (expressed in $2009).

D. Capital

1. Capital Approach

Measuring Capital quantity is less straightforward than measuring Labour or Materials quantity. In recent utility TFP analyses, three approaches to quantifying capital have been used, referred to as "Geometric Decay", "Cost of Service" and "One Hoss Shay".

Geometric Decay: In the geometric decay model, capital quantity reflects the concept that the plant additions of each vintage become less productive, or efficient, over time, and that the pattern of the decline in productivity is geometric. The geometric decay capital price, which is also called the user cost or service price, represents the price of employing a unit of net capital for one year. The capital price is based on the relationship between the price of new capital and the present value of future services of current capital; the Geometric Decay capital price incorporates financial costs and economic depreciation.[99] The economic depreciation[100] component in the price calculation measures the decline in the price of the capital asset as it ages. Capital cost is calculated by multiplying the Geometric Decay capital quantity and capital price. The geometric decay approach has been promoted extensively in academic literature.[101]

Cost of Service: The cost of service approach to calculating capital cost reflects the way capital cost is determined in utility regulation.[102,103] Cost of Service capital quantity is

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99 Economic depreciation measures the change in the market value of an asset over time while the accounting depreciation reveals nothing about the market value. Accounting depreciation is simply the allocation of the historical cost of an asset to the periods in which the services of the asset are recovered from ratepayers.

100 In the case of geometric decay, economic depreciation is equal to efficiency decline.

101 A few example include: Hulten, Charles (1990), "The Measurement of Capital", in Ernst Berndt and Jack Triplett (eds.) Fifty Years of Economic Measurement, National Bureau of Economic Research Studies in Income and Wealth, volume 54, The University of Chicago Press, Chicago.; Hulten, Charles and Frank Wykoff (1981), "The Estimation of Economic Depreciation" in Charles Hulten (ed.) Depreciation, Inflation, and the Taxation of Income from Capital, Urban Institute, Washington.; Mark E Doms, 1992. "Estimating Capital Efficiency Schedules Within Production Functions," Working Papers 92-4, Center for Economic Studies, U.S. Census Bureau; and Nehru, Vikram and Ashok Dhareshwar (1993). A New Database on Physical Capital Stock: Sources, Methodology and Results, Revista de Analisis Economico. 8: 37–59.

102 A few examples include: Lowry, Mark (2007), "Rate Adjustment Indexes for Ontario's Natural Gas Utilities," Report filed on behalf of the Ontario Energy Board.; Lowry, Mark (2011), "PBR Plans for Alberta Energy Distributors," Report filed on behalf of the Consumer's Coalition of Alberta before the Alberta

determined based on the assumption that the efficiency of each vintage of plant additions declines in accordance with a straight line pattern.[104] The Cost of Service capital price is determined by a weighted average of current and past construction or asset prices. As a result, the Cost of Service capital price is an implicit price determined by the deflated sum of financial costs and accounting depreciation. The financial costs and accounting depreciation are both based on the historic (book) value of the plant.

One Hoss Shay: The One Hoss Shay approach to determining capital cost assumes that an asset retains full efficiency until the end of its service life.[105] The One Hoss Shay Capital quantity is measured by gross plant; total gross plant is determined by summing plant additions by vintage. The One Hoss Shay Capital price is computed by incorporating financial costs and economic depreciation; economic depreciation must be estimated using several factors, including the real rate of interest (discount factor).[106]

The simplicity of the geometric model provides several advantages over the cost of service and One Hoss Shay models, including: economic depreciation equals efficiency decline, no system of vintage accounting needs to be maintained because of the constant rate of depreciation, and depreciation is independent of the real rate of interest.[107] The geometric decay model is the only model where the economic depreciation equals the efficiency decay. This simplifies the calculation because it avoids the tedious task of estimating the economic depreciation. In addition, if the two are not equal, the depreciation function can take on several forms due to its sensitivity to factors such as the real interest rate. For example, in the case of One Hoss Shay, if the interest rate is zero, we can conclude that the depreciation will exhibit a straight line pattern; however, if the real interest rate is positive, the depreciation function will exhibit a concave pattern. The geometric decay model eliminates

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utilities Commission.; and Kaufmann, Larry (2011), "Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans," Report filed on behalf of the Ontario Energy Board.

103 The lack of detailed documentation and academic literature on the Cost of Service approach does not permit us to fully understand the methodology.

104 That is, the efficiency of a specific addition to plant declines at the same rate (percent of original plant) each year.

105 This approach was recently promoted by NERA in the Alberta generic IR case. Makholm, Jeff (2010), "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," Report filed on behalf of the Alberta Utilities Commission.

106 Due to the interdependence of the Capital price and economic depreciation, One Hoss Shay economic deprecation will in general follow a concave pattern, which assumes that the price of the asset declines at a slower pace in earlier years and an accelerated pace toward the end of its service life.

107 Harper (1982), "The Measurement of Productive Capital Stock, Capital Wealth, and Capital Services."

the necessity of a depreciation calculation. Furthermore, the geometric decay model does not require a system of vintage accounting due to the constant rate of depreciation. The capital price does not depend on the historical pattern of past asset prices; it only depends on the current price of used assets, which can be expressed in terms of a new asset's price.[108] This greatly reduces the data demands associated with the geometric decay model.

The geometric decay model has been applied empirically on numerous occasions. One highly cited empirical study was developed by Hulten and Wykoff (1981). Hulten and Wykoff estimated the capital price index (age/price profile) by using prices of used capital assets. The study examined three common models: One Hoss Shay, straight line and geometric decay. Hulten and Wykoff concluded that geometric decay was the most appropriate method for estimating the age/price profile. Due to the dual property discussed above (economic depreciation equals efficiency decay), we can also assume that geometric decay would be the most accurate efficiency profile. Other studies using alternative approaches to estimating efficiency schedules have also been conducted. For example, Doms (1992) estimated efficiency schedules within production functions which resulted in relative efficiencies that declined geometrically.

The cost of service model, while trying to more accurately reflect the way capital cost is determined in utility regulation, has not been extensively studied in scholarly literature; therefore, there is no independent evaluation of the approach. In addition, to our knowledge, the model has only been used empirically by Pacific Economics Group. These factors make the cost of service approach difficult to evaluate. In addition, the model contains theoretical inconsistencies. Hulten (1990) showed that economic depreciation and efficiency decay are not independent concepts. One cannot select an efficiency pattern independent of the depreciation pattern and one cannot select a depreciation pattern independent of an efficiency pattern. Hulten used the example of straight line efficiency decay and showed that if one selects straight line efficiency decay then one has committed to using a non-straight line pattern of depreciation. The cost of service model uses straight line efficiency decay and depreciation, which is in direct violation of the theoretical framework developed by Hulten. In addition, accounting depreciation is being incorrectly used a proxy for economic depreciation.

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[108] Fuss (2012), "Response to Pacific Economics Group's September 2011 Report" Report filed on behalf of Union Gas before the Ontario Energy Board.

The One Hoss Shay method assumes that assets retain full efficiency until the asset reaches the end of its service life. However, OECD (2001)[109] states that there are relatively few assets that will actually maintain full efficiency throughout their useful lives. As noted above, Hulten (1990) showed that economic depreciation and efficiency decay are not independent concepts and therefore, cannot be chosen independently of one another. In the case of One Hoss Shay efficiency decline, the depreciation function often takes on a concave pattern.[110] However, a concave depreciation function is often at odds with empirical research. As Hulten and Wykoff (1981) show, depreciation generally exhibits a convex or geometric pattern. Furthermore, if a One Hoss Shay pattern of efficiency for an aggregation of capital assets is used, it is assumed that the useful life of all those assets are the same and that the efficiency decay of each asset is One Hoss Shay. Both assumptions are implausible.

Therefore, Concentric used the geometric decay approach to estimate capital cost and capital price, based on the following considerations:

(a) The geometric decay approach has been studied extensively in the literature and applied empirically in academic studies, including studies of utility regulation.

(b) The geometric approach is (relatively) straightforward.

(c) The Geometric Decay approach is consistent with the theoretical framework for determining capital cost. In capital theory, the price of an asset in a competitive market must be equal to the present discounted value of the expected annual rental rates of that asset over its entire service life with each expected rental rate being weighted by the corresponding annual productive efficiency.[111] The capital quantity and capital price obtained in the geometric decay model satisfies this fundamental equation.

2. Capital Quantity

Capital Quantity is a measure of a utility's distribution capital stock in any year. Capital Quantity reflects the value of the plant that is available to be used in a year, accounting for the value of plant additions in each earlier year and the remaining useful portion of that vintage of plant additions and plant retirements. Ideally Capital Quantity would be measured by compiling the annual additions and retirements, measured in real dollars, starting at a company's inception. However, because published plant data of this nature is

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109 OECD (2001), "Measuring Capital," OECD Manual.

110 Unless the real interest rate is zero, in which case the depreciation function is of the straight line pattern.

111 The theoretical framework is developed in Fuss (2012), Hall and Jorgenson (1967), Hulten (1990) as well as others.

not available for the companies in the Industry Study Group, Concentric estimated the Capital Quantity for a "baseline" year. For the industry study group analysis, the baseline year was 1995;[112] the baseline Capital Quantity was estimated by dividing (1) 1995 book Net Utility Plant, excluding production plant[113] by (2) a composite plant deflator that Concentric developed to reflect the vintages of plant that were in service in 1995. The composite plant deflator is based on the regional Handy-Whitman Index of Cost Trends of Gas Utility Construction ("Handy-Whitman Index"). The formula for calculating the 1995 capital quantity is shown below:

$$K_{1995} = \frac{Net\ Plant_{1995}}{\sum_{i=1}^{30}\left\{\left[\frac{i}{\sum_{j=1}^{30} j}\right] * HandyWhitmanIndex_{1965+i}\right\}}$$

A similar methodology was used for the EGD capital quantity, except that: 1) the baseline year was 2000, and 2) the composite plant deflator was based on the implicit price index for natural gas distribution investments in Canada obtained from StatsCan.[114]

For each company, the Capital Quantity for each year after the baseline year was calculated by summing, for each year, (a) real plant additions; (b) minus real plant retirements; and (c) Capital Quantity in the prior year. Plant additions were obtained from the Company for the EGD analysis, and from the Annual LDC Filings for each utility in the industry study group analysis. Plant additions were converted to real dollar terms using the appropriate utility plant deflator in that year. Because annual retirement data was not readily available, annual retirements for each company were calculated by applying a common depreciation rate to the Capital Quantity in the prior year for consistency. Enbridge's depreciation rate of 4.14% was used for all companies. The formula for calculating capital quantities after the start year is shown below:

$$K_t = K_{t-1} + \frac{Plant\ Additions_t}{UtilityPlantDeflator_t} - [Depreciation\ Rate * K_{t-1}]$$

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[112] The earliest year for which plant data was available for the U.S. natural gas utilities was 1995.

[113] Concentric calculated Book net plant for 1995 by summing 1995 gross plant for all categories of natural gas plant, excluding production, minus 1995 accumulated depreciation for the same categories of natural gas plant.

[114] Source: Statistics Canada, Table 031-0002, Flows and stocks of fixed non-residential capital, by North American Industry Classification System (NAICS) and asset, annual (dollars x 1,000,000); Canada; Current Prices and 2007 Constant Prices; Natural Gas Distribution; Investments; Total Assets; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 6, 2012.

3. *Capital Price*

As discussed previously, the geometric decay capital price represents the price of employing a unit of capital for one year and is based on the relationship between the price of new capital and the present value of future services of current capital. The price of capital is based on the cost of capital, depreciation, and capital gains.[115] The cost of debt for EGD is the cost of debt reflected in EGD's base rates, and the cost of debt for the industry study group is taken from the Moody's A Utility Bond Index for each applicable year, representing year-to-year fluctuations in utility debt costs. The annual cost of equity for EGD is the Board-approved ROE, and the cost of equity for the industry study group is determined from the average allowed return for all US natural gas utilities in each year, as reported by SNL Financial. In order to determine the annual weighted cost of capital, EGD's equity weighting is set at the Board-authorized average equity share for each year and the equity weighting for the industry study group is the average equity weighting for all US natural gas utilities in each year, obtained from SNL Financial. Annual construction costs for EGD are based on a Canadian implicit price index for natural gas distribution investments,[116] and the Handy-Whitman index for the US industry study group.[117] Capital price for all companies is also adjusted for depreciation, based on Enbridge's depreciation rate of 4.14%. The summation of the cost of capital and depreciation applied to the applicable annual construction cost, and reductions for applicable capital gains determine the capital price for each year. Resulting capital prices are smoothed by calculating a four-year rolling average to reduce volatility, prior to application in the capital cost calculation.

4. *Capital Cost*

Annual capital cost is calculated as annual capital quantity multiplied by capital price for both EGD and the industry study group.

E. Input Sub-Index Calculation and Results

Industry input quantity index growth rates for each sub-index is determined by calculating cost weighted averages across the companies in the 25 company industry study group and

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[115] Based on the calculations in Christensen, L, R, and Jorgenson, D.W. (1969), "The Measurement of U.S. Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, No. 4, December, pp. 293-320.

[116] Source: Statistics Canada, Table 031-0002, Flows and stocks of fixed non-residential capital, by North American Industry Classification System (NAICS) and asset, annual (dollars x 1,000,000); Canada; Current Prices and 2007 Constant Prices; Natural Gas Distribution; Investments; Total Assets; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 6, 2012.

[117] Region-specific Handy-Whitman indices are applied to each company in the US industry sample group.

seven company sub-group. Input sub-index results for the 25 company industry study group, the seven company sub-group and EGD for labour, materials and capital are shown in the following figures.

Figure B-3: Labour Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[118] (2000-2011)

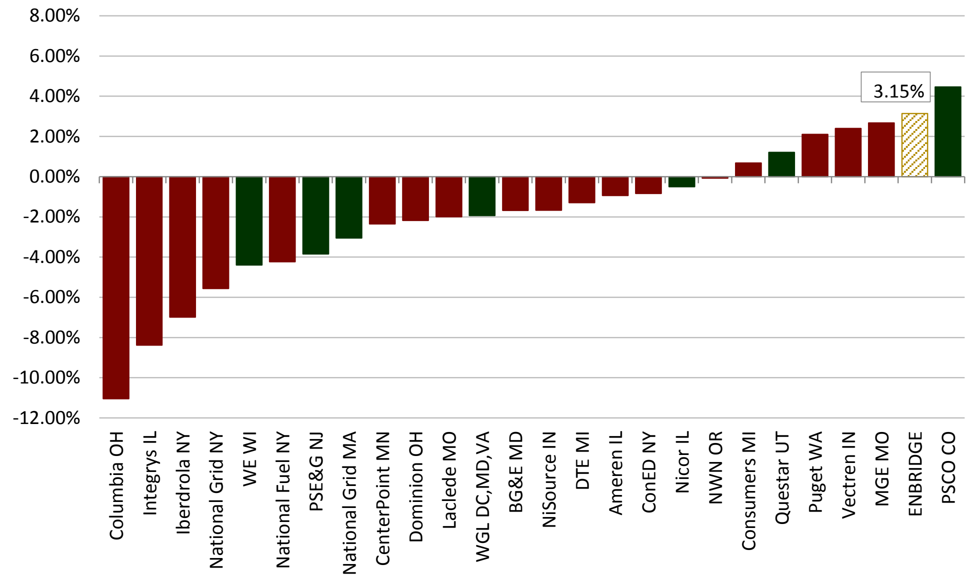
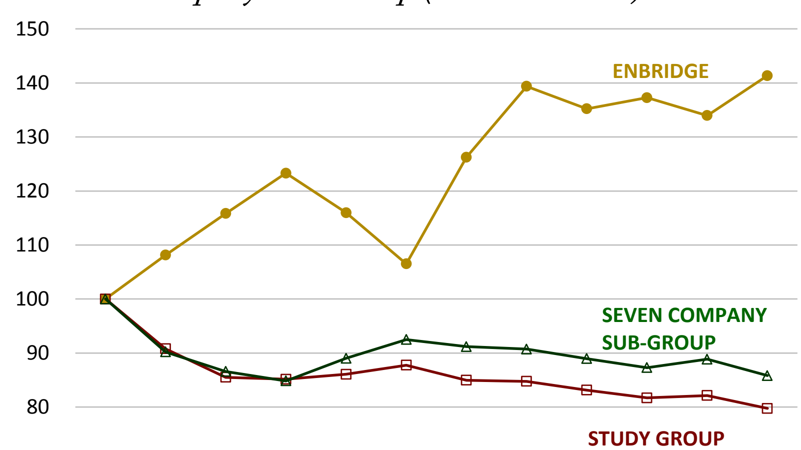


Figure B-4: Labour Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000=100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
EGD	100	108	116	123	116	107	126	139	135	137	134	141
Industry Study Group	100	91	86	85	86	88	85	85	83	82	82	80
7 Company Sub-Group	100	90	87	85	89	93	91	91	89	87	89	86

118 The companies in the seven company sub-group are indicated by green shading.

Figure B-5: Labour Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		7 Company Sub-Group		EGD	
		Labour Quantity Growth Rate	Labour Quantity Index	Labour Quantity Growth Rate	Labour Quantity Index	Labour Quantity Growth Rate	Labour Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	-9.65%	90.80	-10.30%	90.22	7.82%	108.13
	2002	-6.00%	85.51	-4.09%	86.60	6.88%	115.83
	2003	-0.40%	85.17	-2.03%	84.85	6.24%	123.29
	2004	1.07%	86.08	4.80%	89.03	-6.11%	115.99
	2005	1.93%	87.76	3.83%	92.51	-8.52%	106.51
	2006	-3.22%	84.98	-1.42%	91.20	17.00%	126.25
	2007	-0.25%	84.77	-0.51%	90.74	9.88%	139.36
During IR	2008	-1.94%	83.14	-1.96%	88.98	-3.03%	135.21
	2009	-1.73%	81.72	-1.89%	87.31	1.51%	137.26
	2010	0.52%	82.15	1.78%	88.87	-2.43%	133.96
	2011	-2.96%	79.76	-3.48%	85.83	5.37%	141.35
Average Annual Growth Rates							
Whole Period	2000-2011	-2.06%		-1.39%		3.15%	
Pre-IR	2000-2007	-2.36%		-1.39%		4.74%	
During IR	2007-2011	-1.53%		-1.39%		0.35%	

The industry study group and seven company sub-group's labour quantity sub-indices both fell over the study period, while EGD's labour quantity sub-index grew. EGD's labour quantity sub-index grew at an average annual rate of 3.15%, which was the second-highest of the industry study group. However, EGD decreased their labour quantity sub-index growth rate over the more recent 2007 to 2011 period, compared to the earlier 2000 to 2007 period. In contrast, the industry study group's labour quantity sub-index increased in the more recent 2007 to 2011 time period compared to the earlier 2000 to 2007 time period and the seven company sub-group's labour quantity index remained constant.

Figure B-6: Materials Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[119] (2000-2011)

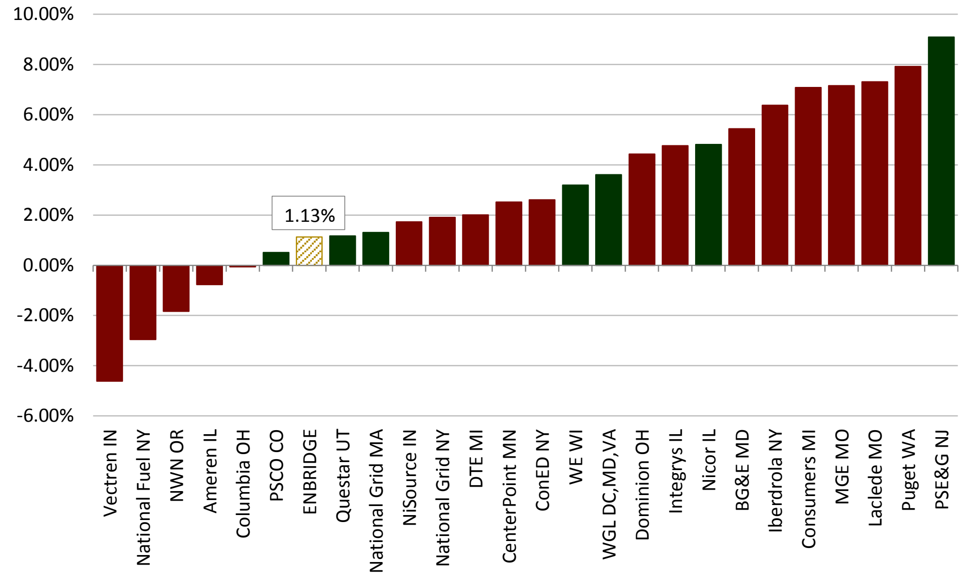
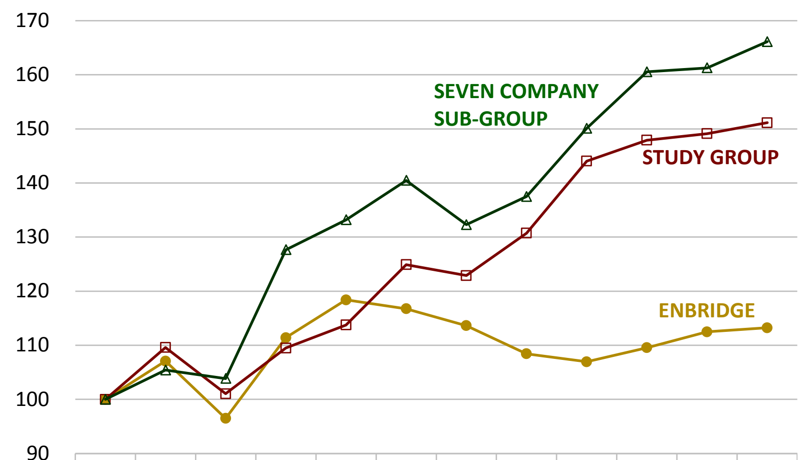


Figure B-7: Materials Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000=100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
EGD	100	107	97	111	118	117	114	108	107	110	112	113
Industry Study Group	100	110	101	109	114	125	123	131	144	148	149	151
7 Company Sub-Group	100	105	104	128	133	140	132	137	150	161	161	166

119 The companies in the seven company sub-group are indicated by green shading.

Figure B-8: Materials Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		7 Company Sub-Group		EGD	
		Materials Quantity Growth Rate	Materials Quantity Index	Materials Quantity Growth Rate	Materials Quantity Index	Materials Quantity Growth Rate	Materials Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	9.17%	109.60	5.27%	105.41	6.84%	107.07
	2002	-8.13%	101.05	-1.48%	103.86	-10.40%	96.50
	2003	8.03%	109.50	20.63%	127.65	14.36%	111.41
	2004	3.81%	113.75	4.24%	133.18	6.09%	118.40
	2005	9.36%	124.92	5.32%	140.47	-1.40%	116.75
	2006	-1.64%	122.89	-6.00%	132.29	-2.72%	113.63
	2007	6.19%	130.74	3.86%	137.49	-4.67%	108.45
During IR	2008	9.69%	144.05	8.78%	150.11	-1.39%	106.95
	2009	2.65%	147.92	6.72%	160.55	2.41%	109.56
	2010	0.82%	149.13	0.45%	161.27	2.64%	112.49
	2011	1.34%	151.15	2.96%	166.12	0.67%	113.24
Average Annual Growth Rates							
Whole Period	2000-2011	3.76%		4.61%		1.13%	
Pre-IR	2000-2007	3.83%		4.55%		1.16%	
During IR	2007-2011	3.63%		4.73%		1.08%	

EGD's materials quantity sub-index grew at an average rate of 1.13%, which was lower than both the industry study group and seven company sub-group averages of 3.76% and 4.73%, respectively. EGD's materials quantity sub-index was in the second lowest quartile of the industry study group. EGD and the industry study group decreased their materials quantity sub-index growth rate over the more recent 2007to 2011 period, compared to the earlier 2000 to 2007 period. In contrast, seven company sub-group's materials quantity sub-index increased in the more recent 2007 to 2011 time period compared to the earlier 2000 to 2007 time period.

Figure B-9: Capital Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[120] (2000-2011)

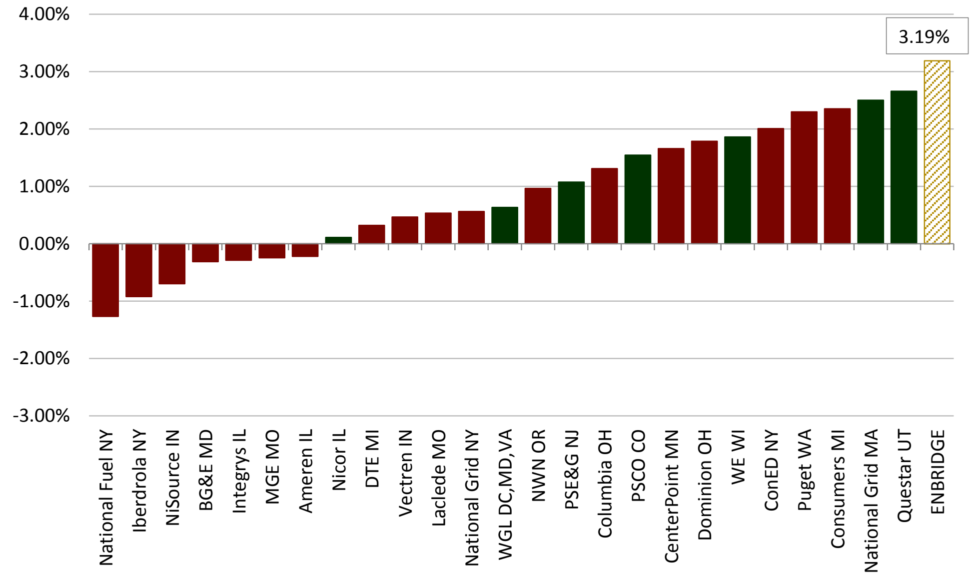
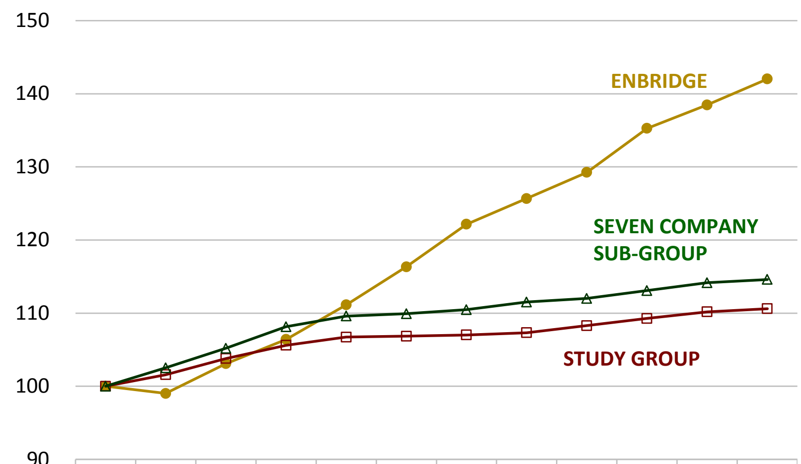


Figure B-10: Capital Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000=100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
EGD	100	99	103	106	111	116	122	126	129	135	138	142
Industry Study Group	100	102	104	106	107	107	107	107	108	109	110	111
7 Company Sub-Group	100	103	105	108	110	110	110	112	112	113	114	115

[120] The companies in the seven company sub-group are indicated by green shading.

Figure B-11: Capital Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		7 Company Sub-Group		EGD	
		Capital Quantity Growth Rate	Capital Quantity Index	Capital Quantity Growth Rate	Capital Quantity Index	Capital Quantity Growth Rate	Capital Quantity Index
	2000		100.00		100.00		100.00
	2001	1.57%	101.59	2.49%	102.52	-0.99%	99.02
	2002	2.15%	103.79	2.58%	105.19	4.04%	103.10
	2003	1.73%	105.60	2.76%	108.14	3.16%	106.41
	2004	1.06%	106.72	1.34%	109.60	4.35%	111.14
	2005	0.12%	106.85	0.29%	109.92	4.57%	116.33
	2006	0.16%	107.02	0.50%	110.47	4.89%	122.16
Pre-IR	2007	0.29%	107.33	0.94%	111.52	2.83%	125.67
	2008	0.90%	108.30	0.44%	112.01	2.80%	129.25
	2009	0.90%	109.28	0.96%	113.09	4.56%	135.27
	2010	0.82%	110.19	0.94%	114.16	2.34%	138.48
During IR	2011	0.39%	110.61	0.38%	114.60	2.53%	142.03
Average Annual Growth Rates							
Whole Period	2000-2011	0.92%		1.24%		3.19%	
Pre-IR	2000-2007	1.01%		1.56%		3.26%	
During IR	2007-2011	0.75%		0.68%		3.06%	

EGD's capital quantity sub-index grew at an average annual rate of 3.19%, which was higher than all other companies in the industry study group. EGD, the industry study group, and the seven company sub-group all decreased their capital quantity sub-index growth rate over the more recent 2007 to 2011 period, compared to the earlier 2000 to 2007 period.

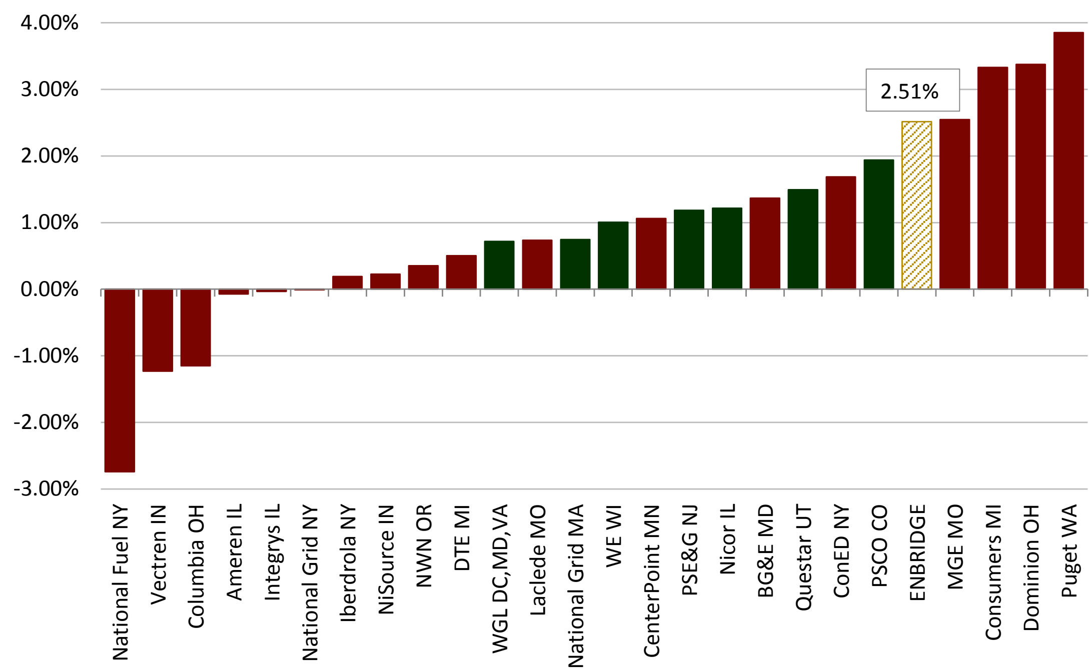
For the 25 company industry study group, the materials quantity sub-index grew at the fastest rate, 3.76%, followed by the capital quantity sub-index, which grew at an average rate of 0.92%, and the labour quantity sub-index, which decreased (declined) at an average annual rate of 2.06%. The sub-index growth rates were similar for the seven company sub-group; the materials quantity sub-index grew at the fastest rate, 4.61%, followed by the capital quantity sub-index, which grew at an average rate of 1.24%, and the labour quantity sub-index, which decreased (declined) at an average annual rate of 1.39%. In contrast, for Enbridge, the capital quantity sub-index grew at the fastest rate, 3.19%, followed by the labour quantity sub-index, which grew at an average rate of 3.15%, and the materials quantity sub-index, which grew at an average rate of 1.13%. As noted in the Output Index

Methodology section, Enbridge's faster output growth helps explain its greater utilization of capital and labour inputs.

F. TFP Input Index Calculation and Results

TFP input quantity indexes and annual growth rates are determined for each company by calculating a cost-weighted average of the input quantity growth rates of the sub-indexes (labour, materials, capital) for each year. Cost weights for each sub-index are developed for each year based on the share labour, materials and capital costs relative to the total costs. Annual input quantity growth rates for each year are calculated as the average growth in the input quantity sub-indexes weighted by the input sub-index cost weights using the Tornqvist-Theil methodology.[121] The industry input quantity index is determined by calculating a cost weighted average input quantity growth rate across all companies in the industry study group for each year. The TFP input quantity index and growth rates for EGD, the industry study group, and the seven company sub-group are shown in the following figures.

Figure B-12: TFP Input Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-group[122] (2000-2011)



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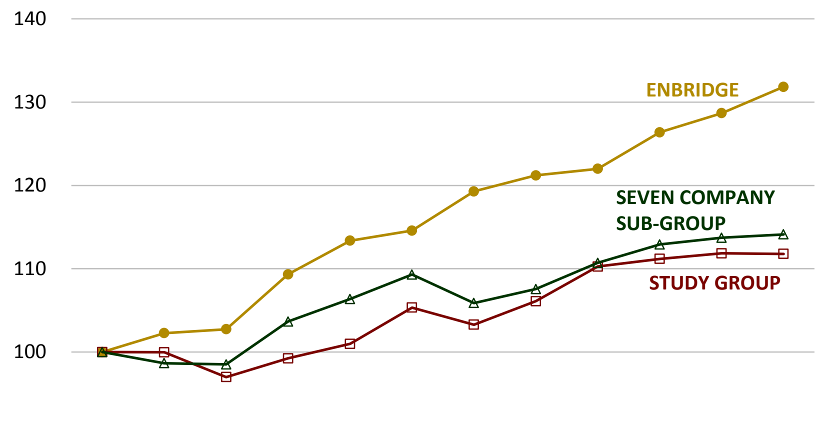
[121] In a Tornqvist-Theil index, the growth rates are calculated as the difference in natural logarithms of successive observations of the components.

[122] The companies in the seven company sub-group are indicated by green shading.

As shown by Figure B-12, 20 of the 26 companies (including EGD) experienced positive TFP input index growth rates over the 2000 to 2011 study period. Between 2000 and 2011, EGD's input index grew at a faster rate than all but four companies in the industry study group, and at a faster rate than all the companies in the seven company sub-group. EGD's higher TFP input index growth rate is due to EGD's comparatively greater capital and labour sub-index growth rates. As will be discussed in the Output Index Methodology section, EGD has experienced more rapid customer growth than most of the companies in the industry study group, which helps explain EGD's higher capital and labour growth relative to the industry study group.

Figure B-13: TFP Input Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	102	103	109	113	115	119	121	122	126	129	132
Study Group	100	100	97	99	101	105	103	106	110	111	112	112
7 Co. Sub-Group	100	99	99	104	106	109	106	108	111	113	114	114

Figure B-14: TFP Input Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	-0.03%	99.97	-1.35%	98.66	2.25%	102.27
	2002	-3.02%	97.00	-0.14%	98.52	0.46%	102.74
	2003	2.28%	99.24	5.09%	103.66	6.21%	109.33
	2004	1.75%	100.99	2.57%	106.36	3.63%	113.37
	2005	4.22%	105.34	2.73%	109.30	1.05%	114.57
	2006	-1.97%	103.29	-3.17%	105.89	4.03%	119.29
	2007	2.68%	106.10	1.56%	107.56	1.59%	121.20
During IR	2008	3.85%	110.26	2.88%	110.71	0.66%	122.00
	2009	0.84%	111.19	1.97%	112.91	3.52%	126.37
	2010	0.59%	111.85	0.72%	113.72	1.81%	128.68
	2011	-0.06%	111.79	0.35%	114.13	2.42%	131.83
Average Annual Growth Rate							
Whole Period	2000-2011	1.01%		1.20%		2.51%	
Pre-IR	2000-2007	0.85%		1.04%		2.75%	
During IR	2007-2011	1.31%		1.48%		2.10%	

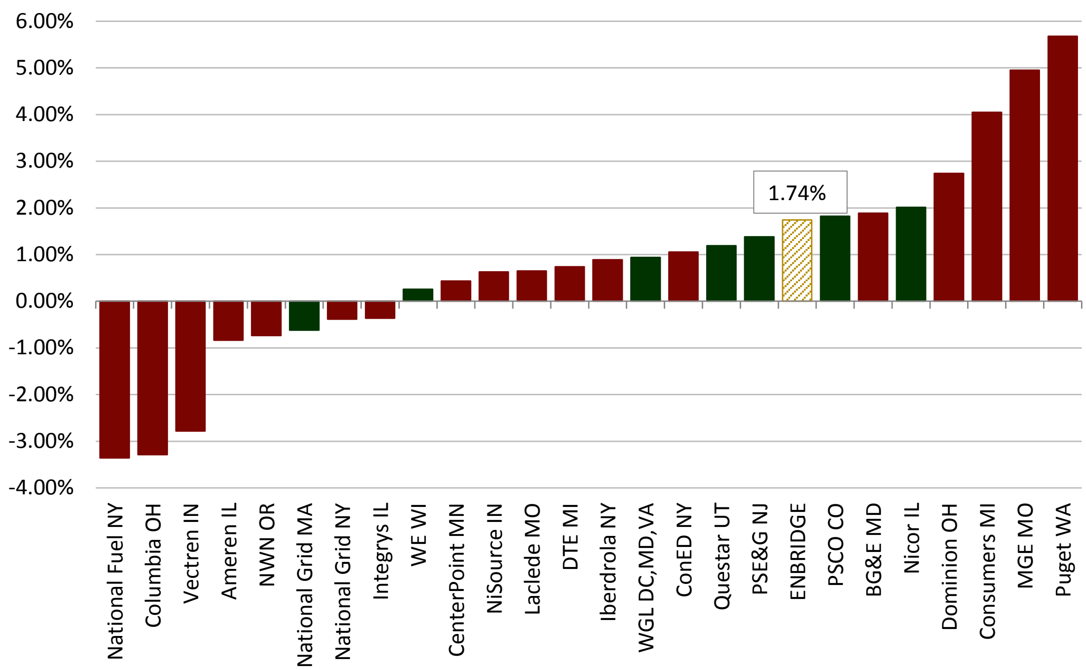
Although EGD's overall TFP input index growth rate has been higher than the industry study group and the seven company sub-group, EGD's TFP input index growth rate was lower during the IR period (2007-2011) compared to the pre-IR period (2000-2007).[123] In contrast, the industry study group's TFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 1.31%, which was an increase of 0.46% over the industry study group's TFP input quantity growth rate from 2000 to 2007. In addition, the seven company sub-group's TFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 1.48%, which was an increase of 0.44% over the seven company sub-group's TFP input quantity growth rate from 2000 to 2007.

[123] EGD's pre-IR Input Index grew by an average annual rate of 2.75%; the Input Index growth rate averaged 2.10% during the IR period.

G. PFP Input Index Methodology and Results

The PFP input quantity index is an aggregation of labour and materials quantity sub-indexes and differs from the TFP input quantity index in that the PFP input quantity index excludes capital quantities. PFP input quantity indexes and annual growth rates are determined for each company by calculating a cost-weighted average of the input quantity growth rates of the sub-indexes (labour, materials) for each year. Cost weights for each sub-index are developed for each year based on the share labour and materials costs relative to the total costs. Annual input quantity growth rates for each year are calculated as the average growth in the input quantity sub-indexes weighted by the input sub-index cost weights using the Tornqvist-Theil methodology.[124] The industry input quantity index is determined by calculating a cost weighted average input quantity growth rate across all companies in the industry study group for each year. The PFP input quantity index and growth rates for EGD, the industry study group, and the seven company sub-group are shown in the following figures.

Figure B-15: PFP Input Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-group[125] (2000-2011)



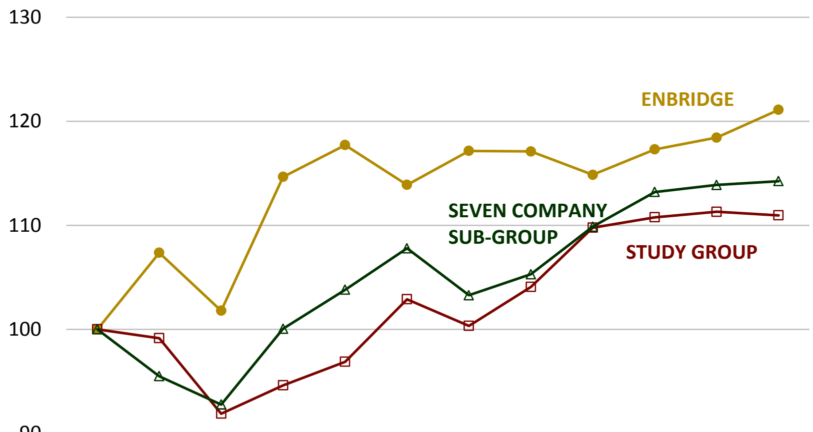
124 In a Tornqvist-Theil index, the growth rates are calculated as the difference in natural logarithms of successive observations of the components.

125 The companies in the seven company sub-group are indicated by green shading.

As shown by Figure B-15, 18 of the 26 companies (including EGD) experienced positive PFP input index growth rates over the 2000 to 2011 study period.

Figure B-16: PFP Input Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	107	102	115	118	114	117	117	115	117	118	121
Study Group	100	99	92	95	97	103	100	104	110	111	111	111
7 Co. Sub-Group	100	95	93	100	104	108	103	105	110	113	114	114

Figure B-17: PFP Input Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	-0.85%	99.16	-4.61%	95.50	7.10%	107.36
	2002	-7.61%	91.89	-2.90%	92.77	-5.32%	101.80
	2003	2.92%	94.62	7.56%	100.06	11.90%	114.66
	2004	2.37%	96.88	3.68%	103.81	2.63%	117.71
	2005	6.02%	102.89	3.77%	107.79	-3.30%	113.90
	2006	-2.51%	100.34	-4.28%	103.28	2.82%	117.16
	2007	3.66%	104.08	1.93%	105.29	-0.04%	117.11
During IR	2008	5.33%	109.77	4.25%	109.87	-1.94%	114.86
	2009	0.91%	110.78	2.99%	113.21	2.11%	117.30
	2010	0.48%	111.31	0.60%	113.89	0.96%	118.44
	2011	-0.31%	110.97	0.31%	114.24	2.23%	121.11
Average Annual Growth Rates							
Whole Period	2000-2011	0.95%		1.21%		1.74%	
Pre-IR	2000-2007	0.57%		0.74%		2.26%	
During IR	2007-2011	1.60%		2.04%		0.84%	

Although EGD's overall PFP input index growth rate has been higher than the industry study group and the seven company sub-group, EGD's PFP input index growth rate was lower during the IR period (2007-2011) compared to the pre-IR period (2000-2007).[126] In contrast, the industry study group's PFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 1.60%, which was an increase of 1.03% over the industry study group's PFP input quantity growth rate from 2000 to 2007. In addition, the seven company sub-group's PFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 2.04%, which was an increase of 1.30% over the seven company sub-group's TFP input quantity growth rate from 2000 to 2007.

[126] EGD's pre-IR Input Index grew by an average annual rate of 2.26%; the Input Index growth rate averaged 0.84% during the IR period.

III. OUTPUT INDEX METHODOLOGY

A. Introduction

In economic terms, output is the "quantity of goods or services produced in a given time period, by a firm, industry, or country,"[127] whether consumed or used for further production. An output index measures trends in the goods and services produced by the company, industry, or economy. Applied to a natural gas distribution company, outputs are generally considered to include metrics such as number of customers, quantities of gas delivered to customers, and deliveries at peak demand conditions. In this case it is appropriate that the Output Index is based on the number of customers served.

The gas distribution output index that Concentric developed for this study is derived from sub-indexes of the number of residential and non-residential customers served, for EGD and each of the industry study group companies. The output index for EGD and each industry study group company is determined by weighting the output sub-indexes by annual company-specific distribution revenue shares (excluding gas cost). To determine the overall industry Study Group output index across all industry study group companies, the relative share of each company's annual distribution revenues are used to weight the output index by company and year.

B. Output Quantity

The output quantity index measures trends in the amount of output produced by EGD and the companies in our industry study group. The measures of output included in the output index are: (1) Residential customer counts, and (2) Non-Residential customer counts.[128]

The two customer count sub-indexes of the output index measure the growth rates in the annual number of customers for the Residential and Non-Residential customer segments. The customer count sub-index for EGD is based on customer data by rate class as reported by the Company. The customer count sub-index for the industry study group is based on annual data, by customer class from Form EIA-176, supplemented with data obtained from the Annual LDC Reports.[129]

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127 Alan Deardorff, Deardorff's Glossary of International Economics.

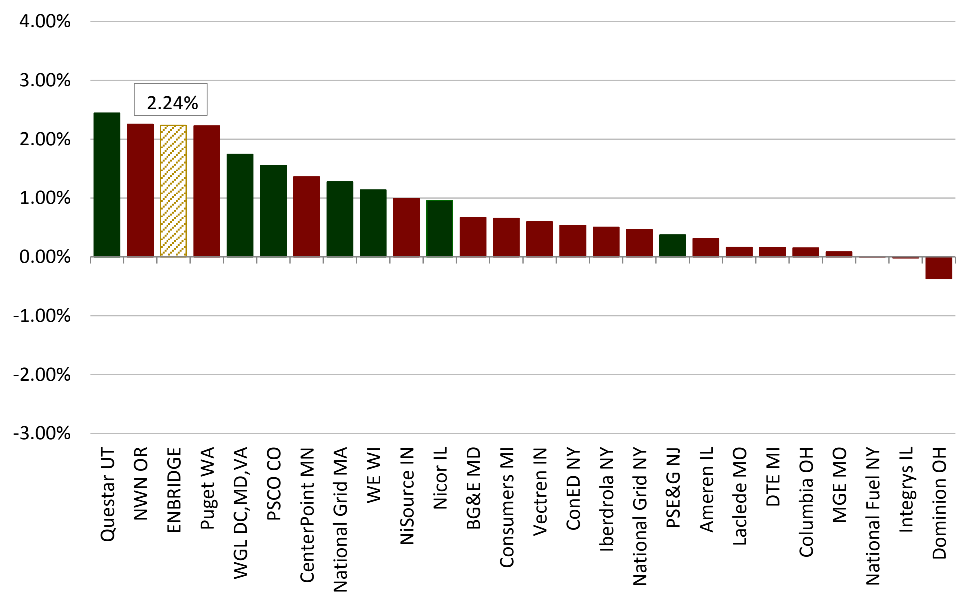
128 The Residential customer segment for EGD includes Rate 1. Non-Residential includes all other EGD firm tariffed rates. For the 25 industry study group companies Residential and Non-Residential (i.e., Commercial/Industrial/Other) is as reported in the Form EIA-176.

129 The measures of output for each customer segment combine data from customers that receive (a) bundled sales and delivery service, and (b) unbundled delivery service from the gas distribution company.

C. Output Index Calculation and Results

To develop the output index for each company, the Residential and Non-Residential customer segment growth rates are weighted by the annual relative shares of company-specific distribution revenues.[130,131] Once output indices are developed for each company in the industry study group, a weighted average is calculated based on each company's total distribution revenues for each year of the study. The EGD, industry study group, and seven company sub-group output quantity indices and growth rates are shown in Figures B-18, B-19, and B-20.

Figure B-18: Output Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[132] (2000-2011)



As shown in Figure B-18, almost all study group companies (23 out of 25) experienced an increase in output quantities (i.e., number of customers) over the 2000 to 2011 study period. EGD's output quantities grew at a faster rate over this period than all except two companies

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130 Distribution revenue is the component of total revenues that is associated with unbundled delivery service. Supply revenue, which is associated with bundled gas supply service, is the other major component of total revenues.

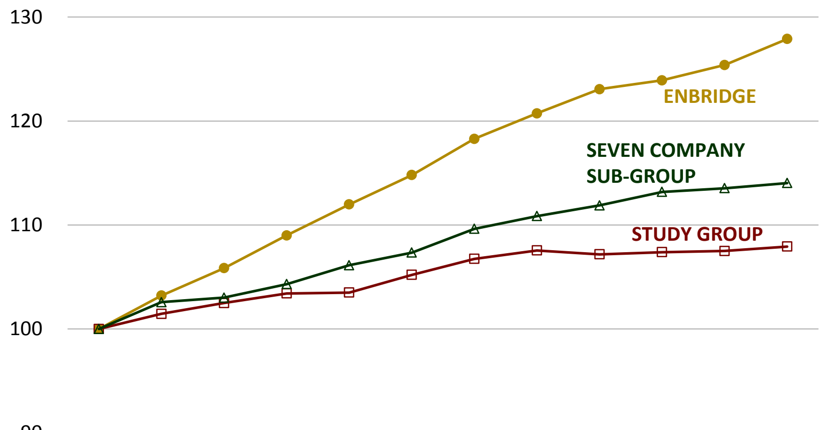
131 Most gas distribution companies, including EGD, offer a choice of either bundled sales service or unbundled distribution service to some or all of its customers. Those customers who elect the unbundled distribution service must obtain gas supply services from competitive suppliers; customers who elect the bundled sales service receive both distribution and gas supply services from the (regulated) distribution company.

132 The companies in the seven company sub-group are indicated by green shading.

in the industry study group, and faster than all except one company in the seven company sub-group. Enbridge's relatively high customer count growth is consistent with the rapid population growth in the Toronto area relative to other metropolitan areas in North America.

Figure B-19: Output Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	103	106	109	112	115	118	121	123	124	125	128
Study Group	100	101	102	103	104	105	107	108	107	107	108	108
7 Co. Sub-Group	100	103	103	104	106	107	110	111	112	113	114	114

Figure B-20: Output Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		Output Quantity Growth Rate	Output Quantity Index	Output Quantity Growth Rate	Output Quantity Index	Output Quantity Growth Rate	Output Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	1.45%	101.46	2.55%	102.58	3.16%	103.21
	2002	1.01%	102.50	0.42%	103.01	2.52%	105.85
	2003	0.90%	103.42	1.25%	104.31	2.93%	108.99
	2004	0.08%	103.51	1.73%	106.13	2.70%	111.97
	2005	1.63%	105.21	1.14%	107.34	2.49%	114.80
	2006	1.45%	106.75	2.11%	109.63	2.99%	118.28
	2007	0.75%	107.55	1.12%	110.86	2.05%	120.73
During IR	2008	-0.34%	107.18	0.92%	111.89	1.91%	123.06
	2009	0.20%	107.39	1.15%	113.18	0.68%	123.91
	2010	0.10%	107.50	0.32%	113.54	1.19%	125.39
	2011	0.40%	107.93	0.43%	114.03	1.98%	127.89
Average Annual Growth Rates							
Whole Period	2000-2011	0.69%		1.19%		2.24%	
Pre-IR	2000-2007	1.04%		1.47%		2.69%	
During IR	2007-2011	0.09%		0.70%		1.44%	

Figure B-20 demonstrates that the industry group, the seven company sub-group and EGD all experienced decreases in output quantity growth rates during 2007 to 2011, compared to 2000 to 2007. The industry study group output growth rate decreased from 1.04% to 0.09%, the seven company sub-group output growth rate decreased from 1.47% to 0.70%, and EGD's output growth rate decreased from 2.69% to 1.44%. The decrease in output growth rates is due to slowing customer growth in recent years, likely due to the impact of the recent economic downturn on the housing industry generally and especially on housing starts.

APPENDIX C: EXECUTIVE BIOGRAPHIES

James M. Coyne, Senior Vice President, is an industry expert who provides financial, regulatory, strategic, and litigation support services to clients in the power and gas utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, cross-border trade, rate and regulatory policy, capital cost determinations, valuations, fuels and power markets. He is a frequent speaker and author of numerous articles on the energy industry and regularly provides expert testimony before federal, state and provincial jurisdictions in the U.S. and Canada. He testifies on matters pertaining to the cost of capital, capital structure, business risk, alternative ratemaking mechanisms and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

James D. Simpson, Senior Vice President, has over 30 years of experience with regulatory relations, regulated pricing and business strategy; he has held senior executive positions at a natural gas utility and an entrepreneurial company providing a proprietary service to generating companies. As Chief Operating Officer for a major New England gas company, Mr. Simpson was responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning. His responsibilities in other positions have included business development, pricing strategy, regulatory affairs, analysis and planning. Mr. Simpson also held staff and director level positions at the Wisconsin Public Service Commission and the Massachusetts Department of Public Utilities; he has an M.S. in Economics from the University of Wisconsin and a B.A. in Economics from the University of Minnesota.

Melissa F. Bartos, Assistant Vice President, is a financial and economic consultant with more than fifteen years of experience in the energy industry. She has conducted comprehensive demand forecast analyses including data collection and validation; model building using various statistical and econometric approaches, and developing presentations, reports and testimony to communicate results. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos has also provided expert testimony regarding natural gas demand forecasting issues. Ms. Bartos previously consulted with Reed Consulting Group and Navigant Consulting, Inc.; she has an M.S. in Mathematics (Statistics) from the University of Massachusetts at Lowell, a B.A. from the College of the Holy Cross in Worcester, MA, and is a member of the American Statistical Association.

The building blocks approach to incentive regulation

Prepared for Enbridge Gas Distribution ("Enbridge") by London Economics International LLC ("LEI")

June 26, 2013

Enbridge Gas Distribution ("Enbridge") has completed its first generation Incentive Ratemaking ("1GIR") plan, where a revenue per customer cap was applied under an I-X escalation mechanism. Enbridge is now preparing an application for a Customized Incentive Regulation ("IR") plan for a period of five years (2014 to 2018). Enbridge has noted in its application that a key driver for the requested Customized IR plan is its projected large and extraordinary capital expenditure profile for the next three years.

At a high level, a customized ratemaking approach is conceptually straightforward, with the idea that a utility will still have strong performance incentives but greater flexibility in managing non-steady state capital expenditure profiles. Some guidance on how this approach can be applied can be taken from the Ontario Energy Board's ("OEB") Custom IR approach designed for electricity distributors in similar circumstances to Enbridge. However, there is limited detail on the practical implementation and no examples of its actual application.

Therefore, to complement Enbridge's consideration of the design of a Customized IR plan, LEI was requested to provide an analysis of building block incentive ratemaking approaches used in other jurisdictions, and how they would apply to Enbridge's circumstances in Ontario.

LEI found that Australia and the UK provide good examples of how IR can be applied to utilities. The frameworks applied in these jurisdictions provide strong efficiency incentives as well as greater flexibility for companies to manage their capital expenditure. These frameworks are clearly not cost-of-service given their rigorous benchmarking and other built in efficiency incentive mechanisms to reduce operating and capital expenditure for the benefit of consumers.

The success of other jurisdictions in applying building blocks IR frameworks for regulation of gas distribution utilities lies in three core areas. Firstly, building blocks motivates productivity, while allowing an opportunity for the regulated utility to earn a commercially reasonable return. Furthermore, building blocks can accommodate both steady state and fast changing capital investment trends, regardless of the drivers for that capital investment. Lastly, building blocks by virtue of the design provides against sudden true-ups in rates.

Enbridge is proposing to adjust its rates annually based on an allowed revenue amount determined through rigorous budget development processes incorporating management directives that limit operating expenditure budget increases to a level at or near inflation and impose an effective labor freeze. Capital expenditure has also been subject to rigorous assessment through the capital budgeting process, which prioritizes projects. Enbridge's approach is consistent with the building blocks form of IR. This approach will both meet the objectives of the OEB as well as the future operating challenges of Enbridge for ensuring that it can attract sufficient capital to fund investments over the medium and longer term. Enbridge's proposed Customized IR plan has commitments for productivity improvements, and other assurances for customers (like the earnings sharing mechanism as well as a Sustainable Efficiency Incentive Mechanism, or "SEIM") to encourage long term efficiency gains.

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1 Executive Summary

The key overarching principles which apply to ratemaking (and are built into the OEB's objectives) are the need to protect consumers, particularly with regards to price, quality and reliability of supply, while providing for a financially viable gas distribution industry. In practice, this may translate into focusing on incentives that provide for sustainable efficiency (productivity) improvements.[1] These principles are commonly applied in IR in other jurisdictions, although the practical approach to achieving particular objectives may differ. For example, Australia and the UK apply a building blocks IR approach which is very much focused on productivity and seeks to achieve similar objectives as enunciated by the OEB. LEI understands that Enbridge in preparing its Customized IR plan has looked to jurisdictions, which apply building blocks, for guidance as to how these could be applied as part of a Customized IR framework.

LEI has extensive experience in advising regulators and utilities on IR frameworks in Ontario, Alberta and across North America. This experience is complemented by LEI's work in Asia, Europe and the Middle East on IR frameworks as well as partnership relationships with IR experts in Australia and the United Kingdom. This puts LEI in a strong position to advise on the spectrum of IR frameworks applied globally and specifically the experience of jurisdictions that have applied the building blocks approach, which is similar to the Customized IR plan that Enbridge is proposing. A summary of LEI's experience can be found in Section 6.

Based on LEI's expertise and experience and in the context of Enbridge's proposed Customized IR plan, LEI has been asked to address several questions:

1. What are the key characteristics of a building blocks approach to incentive ratemaking?

2. How has building blocks been applied in other jurisdictions? Particularly, how have they accommodated regulatory goals and met the needs of utilities' facing situations that are similar to Enbridge - high capital spending requirements and growing depreciation costs? What lessons can be learned from the regimes in other jurisdictions that use building blocks?

3. How does Enbridge's Customized IR plan compare to the successful building blocks model of incentive regulation adopted in other jurisdictions?

The building blocks approach has been successfully applied in the UK for over 20 years and in Australia for almost the same length of time. These approaches have gone through extensive reviews and have remained in place with some adjustments to underlying parameters but not the overarching framework. The building blocks incentive mechanisms have generally proven to be resilient and adaptable to changing circumstances.

[1] See OEB (2005) *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* Report on the Ontario Energy Board Natural Gas Forum

As a next step, LEI evaluated Enbridge's proposed Customized IR plan in the context of its experiences with building blocks regimes and familiarity with the OEB's objectives and OEB's recent guidance on the Custom IR plan for electricity distributors.

In our professional opinion, Enbridge and its ratepayers are well served with the proposed allowed revenue amount arrangement. This has strong productivity incentives and protective elements for the benefit of consumers and is not a cost of service plan.

LEI finds that Enbridge's proposed Customized IR plan is compelling and in particular is designed to deliver successful results against the following objectives:

- ***protecting consumers in respect of price and reliability*** – by design of allowed revenue amounts with strong built-in productivity measures directed by Enbridge's Executive Management Team, customers will not be exposed to any higher rates than dictated by the allowed revenue amounts and ongoing historical approach to adjusting revenue for changes in volumes. The method for establishing the allowed revenue amounts is also better suited for smoothing the rate impact of capital investments between rebasing reviews. In consideration of Enbridge's application, this "bill impact" protection will be critical to support rate stability in light of expected large scale investments in projects to improve gas network reliability (notably GTA and Ottawa projects).[2] Furthermore, the earnings sharing mechanism ("ESM") will provide additional protections for customers to ensure that Enbridge is delivering on the efficient capital spending included in the forecast fixed revenue amounts. The allowed revenue amounts will also support Enbridge's investment in strengthening network integrity and safety for the benefit of customers;

- ***encouraging efficient utilities*** – the embedded productivity measures will provide strong incentives for Enbridge to manage total costs of operation. Furthermore, Enbridge is accepting the risks in more than $160 million of variable capex costs which creates additional strong incentives for Enbridge to manage its cost performance within the term of the plan as it will need to fund any over-expenditure within its allowed revenue amount. Enbridge's supporting evidence, see Exhibit D1, Tab 3, Schedule 1, clearly demonstrates that Enbridge has embedded strong productivity improvements within forecasted Other O&M costs, the subject of the Customized IR plan, as these will continue to decline in real terms over the ratemaking period even while customer numbers increase;

- ***quality of service*** – the performance measures that Enbridge is proposing under the Customized IR plan provide clear service benchmarks which Enbridge must achieve; and

[2] It should also be noted, based on Enbridge's ongoing application for the GTA, there will be bill impact protection from projected reduction in gas costs once the GTA project is completed, as well as the return of part of the site restoration to the cost reserve.

- ***industry financial viability*** – as part of the allowed revenue amount under the Customized IR plan, Enbridge has included a forecast of the allowed rate of return, alongside other critical assumptions such as the schedule of capital investments, customer and volume forecast, productivity improvements in operations, and general inflation. This implies that Enbridge will have an opportunity to earn a fair return on its investments and appropriately recover capex, but only if it indeed can deliver on the productivity and operating cost budgets it has forecast alongside the capital investment requirements. The theory of applying a traditional price cap using a generic Total Factor Productivity ("TFP") based X factor falls apart under such non-steady state conditions, as the Board has recognized in its regulatory guidelines for electricity distribution utilities and Ontario Power Generation. Enbridge's proposal for a Customized IR plan combats this shortcoming of the TFP approach.

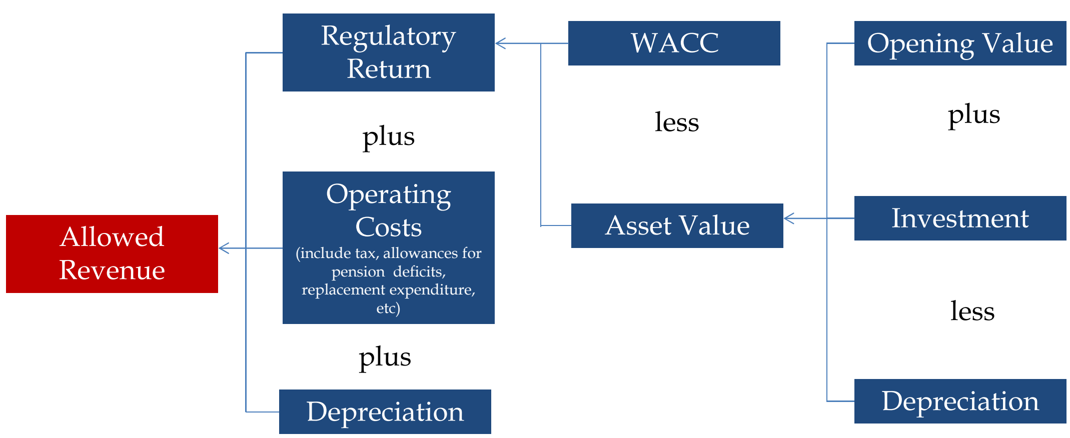
2 What is the building blocks approach to incentive regulation?

2.1 What is building blocks?

The building blocks approach to IR sets a utility's required revenue amounts for each year of the regulatory control period (i.e., IR term) in order to determine the ultimate rate to be charged to customers. The building blocks approach is the effective method for setting of the revenue cap or price cap and the trajectory or annual adjustment thereof. The name building blocks comes from the approach taken to calculate the required revenue amount. To "build up" the revenue requirement, a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each "block" of the revenue requirement for each year of the IR term (see Figure 1). The projected required revenue amount for each "block" can be at a granular level of detail and focus on the firm's past performance and often peer group analysis.

The building blocks approach has been the cornerstone of IR in the UK for over 20 years and in Australia since the late 1990s. The building blocks approach was developed in the UK to derive the components of the price cap regime (RPI-X) that the regulator wanted to apply to newly privatized, monopoly industries, commencing with telecommunications, and then expanding to other network industries in gas and electricity.

Figure 1. "Building up" allowed revenues under the building blocks model



Source: Ofgem (2009) *History of Energy Network Regulation*

The NZ Commerce Commission has also recently adopted building blocks as the model for its customized price quality path for regulation of gas distribution utilities. One of the reasons cited in support of a customized building block arrangement is that "a business may need to invest more in its network than provided for under the default price-quality path [I-X regulation]."[3]

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[3] NZ Commerce Commission (2012) *Customized Price Quality Regulation Fact Sheet* Path http://www.comcom.govt.nz/cpp-fact-sheet/, Given the application of building blocks in NZ is a new

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2.2 Where does the productivity target reside in the building blocks?

In setting the allowed revenue amounts, a utility must demonstrate how productivity improvements have been incorporated, such as by benchmarking projected costs against a firm's historical costs and/or other firms in the industry. These can then also be tested against industry wide TFP studies or other benchmarks.

The individual cost categories illustrated in Figure 1 may be adjusted for inflation, recognizing that a utility needs to be able to appropriately recover its costs. Therefore, if a firm can lower its costs below industry inflation trends, it can further increase its efficiency on top of that which is already built into its allowed revenue amount forecasts. Cost categories may also be adjusted for volume growth. To the extent any costs – opex or capex – are variable with throughput or billing units (number of customers), then they would need to be reflected in the forecast. If the budgeted amounts grow at less than the rate of volumetric growth, that implies economies of scale-driven productivity gains.

In Australia, when building up the investment component, independent engineering reports will be prepared. In the UK, the approach is to look at historical and peer benchmarking as well as industry productivity. Where there are concerns about the past performance of a particular firm, the UK regulator can choose to take a more intensive review of that particular firm. Alternatively, firms can be fast tracked through the regulatory process if they have good historical performance. This allows the regulator to focus resources in areas of need.

Other factors may also be taken into account, in recognition that the operating business environment is dynamic and the future is not always a reflection of the past. In the UK, benchmarking of forecast total costs between utilities may also occur recognizing "the potential for historical costs to bear less relevance to future plans."[4] In addition, the UK under is now also focusing increasingly on output performance rather than input measures and is providing new incentives to assist gas distributors in transitioning to a low carbon energy sector. For instance, Ofgem provides incentives for gas distributors to reduce gas transport losses, to ensure that firms consider the environmental value of carbon abatement, and to fund innovative projects to facilitate the connection of bio-methane.[5]

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development, it is not further discussed in detail in this report as there is no practical evidence of how it has been applied to date. However, the regulator's decision to transition to building blocks is nevertheless enlightening.

[4] Ofgem (2011) *Decision on strategy for the next gas distribution price control – RIIO-GD1 Tools for cost assessment*, March 31, 2011, Supplementary Annex (RIIO-GD1 Overview paper), p.20

[5] Ofgem (2011) *Decision on strategy for the next gas distribution price control – RIIO-GD1 Tools for cost assessment*, March 31, 2011, Supplementary Annex (RIIO-GD1 Overview paper), p. 5

2.3 How is the building blocks method applied to formulate rates under an IR regime?

Once the allowed revenue amount is forecast, it is then translated into a starting revenue requirement referred to as the P_0 and an annual real rate of change, which is referred to as the "X factor," is estimated over the term of the IR plan to provide for the required adjustments in revenue (Figure 2).

The annual adjustment is referred to as I-X in Australia and RPI-X in the UK. In Australia and the UK, the "I factor" or RPI factor is the inflation adjustment. While, the estimated X factor reflects both the productivity target and the real price change required to support a utility's allowed revenue amount on an annual basis. This reference to an X factor can be confusing in a North American context as it is not solely a measure of productivity but reflects an aggregated view of efficiency trends across total costs and the need for efficient capital investment and (potentially) rate smoothing.

Figure 2. Allowed revenue amounts and X factors (2008 to 2013) from UK's gas distribution price control review

	2008/09 P0	2009/10 X1	2010/11 X2	2011/12 X3	2012/13 X4
Total ($ million)	$2,409.46	$2,462.78	$2,463.89	$2,496.43	$2,519.37
X factor		2.2%	0.0%	1.3%	0.9%

Source: Ofgem (2007) 2008-13 *Gas distribution price control review – financial model for final proposals*

Building blocks provides incentives to encourage firms to accurately project capital expenditure requirements with a variety of mechanisms for dealing with differences between forecast and actual capital expenditure including the application of ESM (see Section 4.4 for a detailed discussion) and the adjustment of rates at the next reset to address any differences in capital expenditure.

In the UK, Ofgem uses the Information Quality Incentive ("IQI")[6,7] scheme to further encourage gas distribution utilities to reveal their efficient costs and discourage inflated capital expenditure forecasts through a reward and penalty framework.[8] This mechanism has two components – (i) a component whereby 60% to 65% of any cost outperformance can be retained and (ii) an additional reward of between 0% and 1.5% of total expenditure.

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[6] Also referred to as the "sliding scale incentive" in previous regulatory periods.

[7] As will be discussed later, the IQI scheme was intended to mitigate the information asymmetry between Ofgem, the regulator, and the distributors in capex forecasting and provide incentives to distributors to provide the most efficient level of capex for the requirements of the network over the regulatory period. It aims to reduce the risk of under-investment, reduce the opportunity for distributors with high capex allowances to make high returns for underspend and reward distributors with low capex allowances for delivering against this.

[8] The Information Quality Incentive Mechanism is determined by the following formula:

(Allowed Expenditure – Actual Expenditure)*Efficiency Incentive + Additional Income

Such mechanisms provide incentives for a utility to not only propose efficient and prudent costs as part of its regulatory review, but also to realize timely investment when needed (rather than to game the system so as to time investment with IR terms). The IQI, which has become a key feature of the UK approach, specifically also addresses the information asymmetries problem that regulators have historically been concerned with under cost of service and also, to some degree, under the building blocks approach.

The IQI provides incentives by giving additional income to distributors whose forecast spend is close to Ofgem's assessment. This incentive is realized by providing distributors with a higher incentive rate than those distributors with higher capex forecasts, thereby increasing their reward for outperformance. In designing the revised IQI mechanism, Ofgem notes that "…those that did respond [to Ofgem's proposals] were supportive of retaining the IQI and suggested that this would facilitate accurate information provision, with one respondent also explicitly welcoming extending the IQI to all energy network sectors."[9]

In Australia, the gas utility building blocks framework provides for the incorporation of incentive mechanisms to encourage efficiency in the provision of services. Under expenditure is not specifically addressed in the rule making framework. However, as historical expenditure will be used to inform future ratemaking plans, this provides a disincentive for gas utilities to under-spend. For example, the Australian Energy Regulator ("AER") did make downward adjustments to Jemena Gas Network's ("Jemena") opening capital base for the current (July 2010 – June 2015) regulatory period following a final reconciliation of actual and forecast capital expenditure for 2004-05 which showed capital expenditure A$20.3 million lower than projected.[10] This information was not available at the time of the 2005-2010 determination as the review took place during 2004-05. The AER also adjusted the opening capital base to remove the benefits Jemena had received from applying the rate of return and inflation to this under spend over the period July 2005 – June 2010.

[9] Ofgem (2010) *RIIO: A new way to regulate energy networks*, Final Decision, October 2010, p.32

[10] AER (2010) *Final decision: Jemena Gas Networks: Access arrangement proposal for the NSW gas networks, 1 July 2010-30 June 2015*, see Section 3.5.1.1

3 What has been the practical experience of building blocks?

The building blocks methodology has been well examined in Australia and the UK, and directly compared to TFP-based approaches more common in North American IR regimes.[11] The building blocks approach has been effective in lowering prices in the UK and a recent Australian gas industry productivity study suggests that it has been effective in supporting ongoing industry productivity growth.

3.1 Case study examples of application of building blocks and PTY in other jurisdictions

LEI examined regulatory decisions from Australia and the UK to demonstrate the outcomes of building blocks application in practice (see Figure 3).

Figure 3. Case study analysis of building blocks style incentive regulation approaches

Ratemaking component	JGN, Australia	National Grid, UK
About	835,000 customers in Sydney area (1.1 million across State)	Over 10.8 million consumers
Framework	Price cap with building blocks	Revenue cap with building blocks
Regulatory period	July 2010 to June 2015 (base year 2010)	1 April 2013 to 31 March 2021 (base year 2013)
Earnings sharing mechanism	No formal incentive mechanism	Sharing of efficiency savings from the year these are made, generally on a 50:50 basis. This works the opposite way if the company overspends but only for certain projects.
Treatment of CAPEX	Capex proposals must conform to criteria such as prudent, efficient and good industry practice (See NGR 79 for specific details). JGN submitted expert report on TFP and independent engineering report.	No distinction between opex and capex when calculating the revenue requirements. Benchmarked against past performance and industry plus additional scrutiny if 'poor' performer.
Performance standards	Performance indicators submitted to regulator to support regulatory period expenditure.	Accountable for delivering outputs and system of rewards and penalties. At the end of the regulatory period an over/under delivery of outputs and associated benefits/costs are expected to be carried-over to the next regulatory period.
Other performance incentive mechanisms	Overspending will be reviewed in next reset to determine if reasonable. May carry-over increments for efficiency gains/losses into next regulatory period subject to meeting criteria as discussed above.	There is a detailed reward penalty system, often related to the revenue requirement, to ensure performance (see Ofgem (2010) *RIIO: A new way to regulate energy networks*, Final Decision, October 2010 p.37-38)

[11] See AEMC's *Review of the Use of Total Factor Productivity for the Determination of Prices and Revenues* and Ofgem's *RPI-X@20 Review* at http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

As can be seen in Figure 3, the regulatory outcomes are remarkably similar to those in Ontario. that is: there is a determined rate cap (e.g. a price cap or revenue cap); fixed regulatory periods to incent a utility to operate within the pre-set revenue amounts (see Section 4.3 for a detailed discussion); the application of performance standards and additional incentives (e.g the IQI); and the application of benchmarking and often peer group productivity studies and TFP for evaluating proposed capital expenditures. That is these jurisdictions still prioritize incorporating regulatory objectives such as efficiency improvements and performance standards but provide flexibility for a utility with variable revenue requirements and/or recognize changing circumstances.

3.2 Lessons learned – the experiences of building blocks

3.2.1 UK

The building blocks model in the UK has been successfully implemented and adapted to meet changing circumstances. A recent review by Ofgem[12] has found that the building blocks framework has "…served consumers well, delivering lower prices, better quality of service and more than £36bn in network investment since privatization twenty years ago."[13] This is of particular relevance to Enbridge, which like the UK companies, is also a privately owned gas distribution company operating with the same shareholder pressures and demands from its debt holders. One of the key success factors of the building blocks approach in the UK is its ability to provide incentives to distributors to encourage cost efficiency and quality service while at the same time, ensure that they achieve their fair rate of return. Through the building blocks approach, Ofgem has put in place incentives on distributors to innovate and encourage efficient ways to provide an appropriate level of network capacity, security, reliability, and quality of service. Some of these incentives include a low carbon networks fund, distributed generation incentive, customer satisfaction incentive, customer reward scheme, and innovative funding incentive, and the IQI (as already discussed).

Another key success factor of the building blocks approach in the UK is its ability to adapt to the changing environment. The overarching building blocks framework for gas distribution price control has remained unchanged but has been adapted to allow for new objectives and incentives, for example, to deal with demand side management, energy efficiency and increasing focus on measuring output performance. In the past, the incentives in UK were focused on improvements in cost efficiency. Over time, additional objectives have been introduced such as quality of service and environmental or social-related targets.

In 2010, Ofgem issued its vision for the next generation of building blocks price control, referred to as the RIIO model or the "Revenue set to deliver strong Incentives, Innovation, and Outputs." Under this model, distributors will be able to keep some of the benefits if the business is able to operate at a lower cost or exceed target levels of the performance standards or customer service at the same cost.

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[12] Office of Gas and Electricity Markets, the regulator of gas and electricity markets in Great Britain.

[13] Ofgem (2010) *RIIO: A new way to regulate energy networks*, Final Decision, October 2010, p.2. NB/RIIO = Revenue set to deliver strong Incentives, Innovation and Outputs.

According to Ofgem, the RIIO model has "taken components from the RPI-X framework that work well, incorporated other elements to ensure focus on delivery of a sustainable energy sector, and added elements to promote innovation and smarter gas and electricity networks."[14] Essentially, under the RIIO, Ofgem has maintained the overarching building blocks framework but has adapted it to strengthen the financial performance incentives, encourage innovation and strengthen the focus on outputs. [15]

Under this model, base revenues and incentives are linked to the delivery of the outputs and target levels for performance, which are set for the duration of the eight-year price control period.[16] Gas distributors will then determine the best way to deliver outputs within the revenue constraint. They will be incentivized through rewards for delivery and penalized for non-delivery. The RIIO model, commencing 2013, will also continue with some of the incentives currently provided to the gas distributors[17] and will include new incentives.[18]

3.2.2 Australia

In Australia, the general confidence that the regulator and the regulated utilities put in the overall framework of the current regime suggests that the building blocks framework has also been successful. There has been evidence that the building blocks regime has supported gas distribution network industry productivity as reflected in productivity analysis.[19] A recent study has found that over the period from 1999 to 2009 productivity trends across the Australian gas distribution networks have remained positive, although productivity growth has slowed in recent years. [20] For the Victorian based gas networks the average annual growth rate was 1.7%, while Jemena (New South Wales) and Envestra (South Australia) have had TFP growth rates of 1.9% and 1.4%.

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[14] Ofgem (2010) *Handbook for Implementing the RIIO Model*. October 4, 2010, p. 2

[15] A target is set *ex ante* and the distributors are rewarded (or penalized) if they outperform (or underperform) the goals set during the price review. Distributors will be rewarded or penalized according to the following parameters: (i) customer interruptions, (ii) customer satisfaction, (iii) percentage of units that are lost in distributing electricity to customers, and (iv) efficiency of connection of distributed generation.

[16] The price control review (or the regulatory period/term will be extended to eight years (previously five) with a 'mid-term' review mechanism which is expected to drive greater productivity.

[17] These incentives include risk sharing through the efficiency incentive rate, IQI, and provision of uncertainty mechanisms.

[18] Ofgem offers the following incentives under the RIIO: (i) *Discretionary reward scheme* - rewards firms that can demonstrate that they have delivered additional outputs that contribute to environmental (or social) objectives beyond those funded at the price review. Ofgem proposes an award that will be issued in three tranches of £4 million; (ii) *Shrinkage allowance* – provides an incentive for gas utilities to outperform the allowed volume of gas shrinkage. If reported shrinkage is below the allowed volume, the gas utility retains the cost savings. If shrinkage is above the allowed volume, it will incur the cost of purchasing the additional gas; (iii) *Environmental Emissions Incentive* – provides incentives to utilities to manage gas leakage to the environment using an incentive rate based on the social value of carbon. If gas utilities reduce leakage below their baseline, they will earn a financial reward equal to the environmental benefit associated with the reduction in carbon emissions. The reverse will apply if the volume of leakage is higher than the baseline.

[19] This is only the pipeline component. Retail services are separate businesses in Australia.

[20] Lawrence, Denis and Kain, John (2012) *The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*

Building blocks has also supported large increases in investment for some networks over the current and previous 5 year ratemaking period – 162% increase for Envestra (SA) 71% increase for Envestra (Qld) and 59% for Jemena.[21] Investment drivers are similar to Enbridge in that they will support increasing customer growth, replacement of ageing assets (e.g. replacement of cast iron and unprotected mains) and maintenance of capacity to meet customer demand. This has occurred with increases in retail prices only a few percentage points above the inflation rate.

Network businesses have strong incentives to make the required investments, as any under expenditure will be taken into account in future rate periods. A network business is at risk of rejection of its future capital proposals, including asset replacement programs, where there is a history of underspend.[22]

The Australian Energy Market Commission ("AEMC")[23] has reviewed whether or not to apply a TFP-based method for escalating rates (via an "I-X" framework) or to retain the building blocks approach. Utilities raised concerns about the ability of the TFP-based approach to cope with a "non-steady state" environment. The AEMC noted that the TFP model was reasonably flexible so long as there are regular price resets or equivalent safeguard mechanisms in place (such as the ability to opt in to a building blocks approach if required, and/or off ramps and capital modules). The study found that both the TFP and building blocks approaches provide broadly similar incentives, for a similar length of price control period; and the extent to which efficiency benefits are shared with consumers was also similar (with the observation being that greater required sharing with consumers leads to smaller incentives for implementing cost controls). [24] At the same time, the AEMC noted that there were practical challenges to the TFP-approach, in that it relied exclusively on historical, industry-wide TFP studies, which had not been done to date on such a comprehensive basis. There was concern that data problems could prevent such studies from being sufficiently robust for purposes of ratemaking and that most importantly the lack of data "prevents proper testing of the conditions need for TFP methodology;" therefore the AEMC concluded that it is better to retain the building blocks approach.[25]

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[21] AER (2012) *State of the Energy Market 2012*, Chapter 4 Gas pipelines

[22] AER (2013) *AER issues final decision on the Victorian gas price reviews*, news release, 15 March 2013

[23] The AEMC is the rule maker for the Australian energy markets, in the case of gas network regulation this applies equally to all jurisdictions, except Western Australia, under the *National Gas Law* and *National Gas Rules*.

[24] Brown, Dr Toby and Moselle, Dr Boaz (2009) *Incentives Under Total Factor Productivity Based and Building-Blocks Type Price Controls*, report prepared for the Australian Energy Market Commission by the Brattle Group, see Executive Summary. Highly stylized modeling was also undertaken to assess the differences between the incentive structures of the two models (see Lawrence, Denis and Kain, John (2010) *A Model of Building Blocks and Total Factor Productivity-based Regulatory Approaches and Outcomes*, report prepared by Economic Insights Pty Ltd for the Australian Energy Market Commission). The model assumed a steady state environment and found that for one-off reductions in opex and capex building blocks and I-X are broadly similar but that for ongoing capex reductions (10% per year) TFP has stronger incentives.

[25] AEMC (2011) *Review into the use of total factor productivity for the determination of prices and revenues*

4 Evaluation of Enbridge's Customized IR plan in the context of a building blocks framework

Enbridge's Customized IR plan has the same overarching characteristics of IR plans in jurisdictions using a building blocks approach that is a multi year fixed term, built in productivity measures and other incentive features. The application of an ESM complements the incentives built into the plan, providing an incentive for a utility to improve its efficiency but also to allow customers to share in the benefits, and furthermore safeguard consumers if there is actual under-spending of allocated capital investment in the allowed revenue amounts during the term of the plan. The Sustainable Efficiency Incentive Mechanism ("SEIM") will provide further incentives to encourage long term efficiency gains.

4.1 Summary of Enbridge's Customized IR plan

Enbridge's Customized IR plan (see Figure 4) has the same elements as those used by the OEB to describe the custom ratemaking approach in the *Renewed Regulatory Framework for Electricity Distributors*[26] and illustrates how Enbridge will meet each of those elements.

Figure 4. Key features of Enbridge's Customized IR plan

Form	Customized IR plan (2014-2018)
"Going in" rates	Determined in single forward test-year cost of service review
Cap index	Allowed revenue amount under a revenue cap
Coverage	Comprehensive (capital and O&M)
Annual adjustment mechanism	Allowed revenue amount
Inflation	Inflation within O&M budgets
Productivity	Built into allowed revenue amounts including Executive Management directed O&M costs limited to level or near inflation plus staff freeze Sustainable Efficiency Incentive Mechanism to encourage long term efficiency improvements
Role of Benchmarking	Benchmarking been undertaken to assess the reasonableness of Enbridge's performance against its peers
Sharing of Benefits	To share earnings (50:50) more than 100 basis points above allowed annual ROE
Term	5 years
Off-Ramp	Review of IR plan if earnings are ± 300 basis points off ROE Calculated using OEB ROE formula
Treatment of unforeseen events (Z factor)	To protect against unexpected costs/savings outside of management control that have a revenue requirement impact of >$1.5M.
Deferral and variance	Exhibit D1, Tab 8, Schedule 1
Performance reporting and monitoring	Exhibit A2, Tab 11, Schedule 2

[26] See p.13

The key productivity measures include:

- freezing the number of employees at a full time equivalent ("FTE") level;
- accommodating variable costs within the existing annual revenue amount thereby encouraging Enbridge to prioritize expenditure and seek further efficiencies; and
- Executive Management Team requirement that Other O&M expenditure increases are limited to a level at or near inflation despite ongoing growth in customer numbers and an expectation that some costs will exceed this cap, for example benefits are forecast to increase above 6% annually from 2014 onwards. This will be achieved by identifying efficiency initiatives to accommodate increasing future O&M demands and business requirements.

4.2 Approach to embedding productivity in the allowed revenue amounts

Enbridge, in preparing its allowed revenue amounts, has embedded productivity at a granular level and through Executive Management Team directives that costs must be capped at certain levels and employee levels frozen. This approach imposes strong productivity incentives on the firm and reflects that management is looking closely at containing total operating costs.

The detailed analysis undertaken by Enbridge is highlighted in Exhibit B2, Tab 1, Schedule 1 for the capital budget and Exhibit D1, Tab 3, Schedule 1 for the O&M budget. LEI finds that the approach taken by Enbridge is consistent with that applied in jurisdictions using building blocks as evidenced by the following attributes:

- the setting of overall budget objectives by management;
- detailed review and analysis of proposed costs to prioritize and determine their reasonableness. This has been particularly important for prioritizing expenditure on capital projects;
- comparison of O&M costs with past performance at a high level to determine reasonableness; and
- preparation of benchmarking and TFP analysis to also gauge the reasonableness of Enbridge's Customized IR plan and forecast of allowed revenue amounts.

It would appear from Enbridge's pre-filed evidence that it is well aware of the challenges that imposing an annual revenue amount will have on its ability to meet the needs of its operations while containing costs. Enbridge has acknowledged that its staff will have to work hard to achieve the required productivity targets in the face of the unprecedented capital expenditures and also challenging operating conditions.

4.3 IR Term/Regulatory Period

A key feature of the Customized IR plan that Enbridge is proposing is the automatic cost performance incentive built in by having a multi-year ratemaking period. Enbridge is proposing a five year term consistent with the OEB pre-set five year term for electricity distributors applying under the Custom IR mechanism. Specifically, Enbridge is proposing a five year term with an update in 2016 to set the aspects of the 2017 and 2018 allowed revenue amounts associated with capital expenditure; such an update is necessary given the inherent forecasting uncertainty of Enbridge's specific capital investment plan. A five year plan that is coupled with an update will allow Enbridge to address the cost uncertainties thereby protecting customers from any rate shock due to the mismatch between actual and forecast revenue and also ensuring Enbridge can maintain a financially viable business and fund necessary capital investment over the entire term of IR.

The length of the regulatory period needs to balance competing pressures. A longer period can increase the motivation for the utility to make cost reductions as it will be able to retain increased profits over the term (subject to the terms of an ESM if one is applied). However, frequent resets may also negatively affect utilities' investment planning. Conversely, longer periods between resets potentially increase the risk of rate shock because of the increased likelihood of discrepancies between actual and forecast expenditure increases – a disadvantage to both consumers and utilities.

In a longer IR regime, there is a greater risk the circumstances may not turn out as forecast and the targeted productivities cannot be achieved. The relative preference for term may also be affected by the form of rate cap and annual adjustment mechanism relative to a utility's capital investment plans: if there is significant uncertainty, especially as it relates to capital investment, a utility may prefer a shorter term in order to be able to reflect updated capital investment expectations in rates on a timely basis. This is also to the benefit of consumers as capital expenditure can be monitored and rates adjusted as required, including downwards if capital is not spent.

Based on industry precedent and the form of revenue cap that Enbridge has proposed, an IR term of five years will provide sufficient certainty regarding regulatory treatment. Furthermore a five year timeframe with a mid-term review for the most uncertain element of the annual revenue amount (e.g., capital expenditure) is not so long as to concern regulators and utilities that capital investment plans are inaccurate. There is no ideal term for an IR regime and it will depend on the circumstances faced by each firm and the other components of IRM. Even in the UK, which has recently extended its ratemaking period to eight years, there is recognition that there is "potential for increased uncertainty under a longer control period."[27] In fact, Ofgem specifically provided for a mid-period review, where prices could be re-set or modified, if a material change has occurred. Although regulators and utilities (as well as other stakeholders) would like to minimize the regulatory burden of frequent ratemaking reviews, in a dynamic environment with rapidly changing operation environment and/or significant incremental capital investment needs, a regulated firm may not be able to wait five years to revisit prices.

[27] Ofgem (2010) *RIIO: A new way to regulate energy networks: Final Decision*, October 2010

Similarly, regulators recognize that waiting may not be in the benefit of consumers, who seek rate stability, as the likelihood of a more significant rate shock increases as the term increase.

A five year term is actually longer than the building blocks approach in the UK and Australia, after adjusting for the fact that these other jurisdictions do the re-basing as part of the first year of their term and taking into account that in the UK, there is now also a mid-term review. This longer term will build in stronger efficiency incentives. Enbridge's approach compared with the UK and Australia differs as follows:

- two years longer overall than the UK with the review proposed for capital expenditure the same length as the UK's midterm review (rate rebasing plus three years); and

- one year more than the schedule applied in Australia if the rate rebasing is considered as the first year of the Australian building blocks approach.

For Enbridge, with its large capital expenditure profile for the coming years and associated uncertainties regarding total costs, it is reasonable to have an update mechanism. The forecast error of any projections for capital investment will increase geometrically (if not exponentially) with the period of forecast. The increasingly level of variable costs from $25.1 million in 2014 to $75.9 million in 2016 illustrates how rapidly forecast uncertainties can increase. Projecting long term costs in an environment of such large capital expenditures and variable cost uncertainties would be a highly forecast error-prone process leading to potential under (over) recovery of capital expenditure and consequent rebasing and rate impacts for customers.

4.4 Earnings Sharing Mechanism

> **Enbridge's Proposed ESM**
>
> To provide customers with benefits should there be too wide a divergence between revenues and costs.
>
> Specifically Enbridge is proposing sharing earnings on a 50/50 basis between shareholders and customers when 100 bps above allowed ROE.

One of the objectives of IR is to motivate management to improve efficiency by weakening the connection between incurred costs and allowed prices. Nonetheless, regulated prices should not get too far out of line with actual costs. Therefore, many jurisdictions have employed additional mechanisms to balance such concerns. One type of mechanism is known as an Earnings Sharing Mechanism or "ESM".[28] If the formulaic or fixed revenue requirement adjustments result in a too wide divergence between prices and costs, the extra-normal earnings (or losses) are shared between the company and its customers rather than retained (or absorbed) entirely by the company. Enbridge is proposing specifically a single direction or asymmetric ESM. This will contribute significantly to what would be deemed customer benefits ensuring that if indeed the annual revenue amounts are higher than otherwise needed (because, for example, the forecast for capex was higher than actual capital investment spending), this would not yield supra-profits for the utility over the IR term.

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[28] In UK, cost savings and overruns (and not earnings) are shared with the customers through the IQI scheme.

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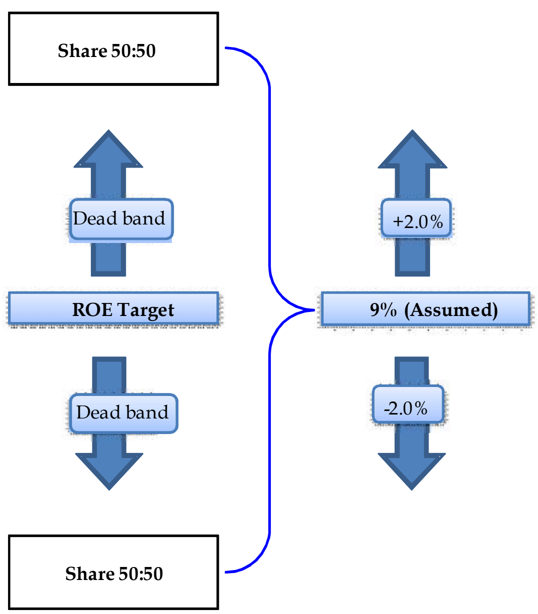
The concept of the ESM is not novel in its application in the building blocks regulatory regimes. In UK, cost savings and overruns (but not earnings) are shared with the customers through the IQI scheme. In Australia, as previously mentioned, the sharing occurs ex post - cost savings will be returned to customers at the next ratemaking period and a firm may also be required to compensate any ROE for forecast capital expenditure that was not actually spent.

It should be noted that there is some opposition to ESMs as a basic construct, because it complicates administration of a IR system; and in theory, it weakens the productivity incentives created by moving to IR. Some critics have even argued that ESM is not technically essential for successful IR implementation. However, by allowing customers to share in benefits which arguably would not have occurred in absence of incentives, the overall political acceptability of an IR plan is increased with an ESM. Furthermore, Enbridge is proposing a one-sided or asymmetric ESM, which is a significant advantage to consumers.

Moreover, true-ups under an asymmetrical ESM mechanism can smooth out the perceived impact of rate increases during the re-basing or review stage. Furthermore, an ESM helps avoid the possibility of unscheduled regulatory interventions, such as windfall profits taxes, which distort patterns of investment and returns. ESMs generally consist of three elements: a target ROE, a dead band around that ROE in which no sharing takes place, and sharing of gains or losses which are outside of the dead band as shown in Figure 5.

Figure 5. ESM design elements



Source: LEI (2011) *Performance based rate making in Canada: best practice, key principles and lessons learned in forming a regulatory regime*

Dead bands and sharing percentages can either be symmetrical or asymmetrical. "Symmetrical" means that customers share equally or proportionally both upside and downside risks, while "asymmetrical" means that either customers or the regulated utility are taking on a disproportionate portion of the risk. In addition, sharing percentages may be gradated, where customers or the firms achieving a greater proportion of savings or bearing a greater proportion of costs as profits increase or decrease. The decision of whether to incorporate gradate sharing is based on whether the added complexity in the formula outweighs the incentive gained in doing so. Some believe that as efficiencies become harder and harder to achieve, firms should be permitted to retain a greater proportion of the resulting savings; others on the other hand, argue that higher levels of savings can result in supernormal returns for the firms if not disproportionately shared with customers.

ESM can vary in the implementation details but broadly encourage firms to operate efficiently and provide customers with an opportunity to benefit where cost savings and/or outperformance are shared with customers. There is a fine balance between encouraging firms to operate efficiently and sharing benefits with customers. Where a utility does not have a sufficient opportunity to benefit from investments to reduce costs, then there may be no action to improve efficiency which is detrimental to everyone.

Enbridge's proposal to continue its conservative, customer-favoring ESM is consistent with all the principles discussed above and will provide a strong incentive to implement efficiency measures, as Enbridge will receive the initial benefits, while customers will also share in the gains above the threshold. Furthermore, the ESM under a building blocks approach discourages cutbacks in investment to boost profitability as these ultimately will be returned to customers.

4.5 Sustainable Efficiency Incentive Mechanism ("SEIM")

The proposed SEIM provides a long term incentive to encourage implementation of efficiency measures by providing Enbridge with an incentive payment of 20% of the net present value of projected productivity gains from a qualifying project for the life of the project. The net present value of the estimated benefits will be adjusted downwards by 10% for any potential forecast error recognizing this is based on projected gains. Enbridge will make an application for each SEIM payment in conjunction with the ESM and the application will be subject to a high level of scrutiny with stakeholders having the opportunity to seek clarity on and question the assumptions behind the proposals.

Regulators are increasingly recognizing the limitations imposed by allowing a utility to benefit from efficiencies achieved only during the term of the IR plan. While mechanisms may vary in the detail, they have a number of common features – a fixed term, limits on the amount a utility can retain, ex post awarding of the benefits and a review or application mechanism to demonstrate that savings have occurred. They all also recognize that unlike rate periods which are finite, utility operations operate over longer and more dynamic timeframes.

The Alberta Utilities Commission ("AUC") has approved an efficiency carry-over mechanism ("ECM") for ATCO Gas, ATCO Electricity and EPCOR which provides for an upper limit on the earnings that can be carried over between regulatory periods of 0.5% of ROE to apply for two years after the end of the previous IR plan.[29] Any other gas or electric utility wishing to apply an

[29] EPCOR also proposed carrying over earnings deficiencies but this was not supported by the AUC. A mechanism proposed by ATCO Electric for carrying over K factor efficiency savings was also not approved.

ECM may also do so in their annual filings. In its decision on IR, the AUC noted "that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR [IR] term and may discourage gaming regarding the timing of capital projects. The Commission [AUC] finds that the incentive properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term."[30]

In Australia, an efficiency sharing mechanism, the Efficiency Benefit Sharing Scheme ("EBSS"), for sharing gains and losses is applied under the building blocks approach for electricity distributors. The EBSS allows electricity distributors to roll over the benefits gained from efficiency measures between rate periods for a period of an additional five years. Under the EBSS, a utility can implicitly retain 30% of the efficiency savings ensuring that both the customer and the utility can benefit from efficiency measures. The regulator, the AER, considers this provides sufficient incentives for an electricity utility to make efficiency improvements. Performance is currently based on benchmarking actual against a utility's historical expenditure but may change in the future to compare with an external benchmark such as an industry based benchmark.[31]

In the UK, the overarching principle is that utilities can carry-over, over or under, delivery of outputs between rate periods with the gas network incurring the costs or benefits of the under or over delivery. This includes maintaining incentive payments and penalties for meeting reductions in gas leakage rates for a period of eight years. The incentive payment is 2.5% of the additional costs associated with a material over-delivery if it is justifiable in the consumer interest. Conversely, a penalty of 2.5% of the avoided costs associated with the under-delivery will be applied.[32]

LEI finds that Enbridge's proposed mechanism is consistent with the overarching principles applied in other jurisdictions for allowing 'roll over' mechanisms for efficiency savings. There are underlying similarities in that the SEIM seeks to encourage ongoing productivity improvements over a time period longer than the ratemaking plan. The SEIM mechanism recognizes two factors. Firstly, gas industry investment cycles are not governed by the artificially imposed timeframes set by regulators but are determined by the much longer term nature of the investment cycles in a capital intensive industry. Secondly, by carrying over efficiency savings between regulatory periods, a gas utility has the incentive to continuously implement efficiency measures as it will receive a return on its investment over a longer period therefore making the investment more attractive.

At the same time, Enbridge's proposed SEIM is focused on specific projects and is subject to public scrutiny. This element of Enbridge's proposed SEIM makes it much more directed than the ECM schemes and carryovers applied in other jurisdictions. However, the key difference in Enbridge's proposal from the above schemes is that it is based on estimated rather than actual, verifiable efficiency benefits or output gains with the forecasting error adjustment a way of

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[30] AUC (2012) *Rate Regulation Initiative: Distribution Performance-Based Regulation*, September 12, 2012, p.169

[31] AER (2013) *Expenditure incentive guidelines for electricity network service providers*, Issues paper (March 2013)

[32] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p.69

addressing the uncertainty in the estimates of the benefits. In summary, the proposed SEIM arrangement provides a positive incentive for Enbridge to implement efficiency measures towards the end of a regulatory period or over longer timeframes, where they might otherwise be discouraged from doing so as the timeframes may be too short for them to recover their costs.

4.6 Overall findings

Having reviewed the Customized IR plan proposed by Enbridge in the context of the Board's objectives and the experience of other jurisdictions with a similar building blocks approach, LEI finds that Enbridge's Customized IR plan meets the objectives of the OEB and will provide benefits to consumers. In short, Enbridge's Customized IR plan:

- builds in strong productivity measures by virtue of the limits it puts on the rates that Enbridge can charge its customers. The forward-looking determination of a set allowed revenue amount for each year of the term of the Customized IR plan commits Enbridge to safely and effectively operating its utility business under a very specific and firm "cost envelope," as described in Enbridge in its own application. The Customized IR plan also embeds a forward looking commitment on Enbridge to meet its own cost and productivity goals, as the actual expenditures made during the term of the Customized IR plan will be open for review when Enbridge prepares its next IR plan. Most impressively this process has resulted in other real O&M costs per customer (just over 50% of the O&M budget and excluding costs already reviewed by the OEB) continuing to decline over the regulatory period. This is occurring at a time when customer numbers are projected to further increase, demonstrating that Enbridge has embedded not only commitments for overall productivity improvements but also economies of scale efficiency gains; Enbridge is taking on real risks and challenges to contain costs over the term of the Customized IR plan. If, for example, variable capital costs come to be realized during the term of the Customized IR plan, Enbridge will need to fund those during the term through its pre-set allowed revenue amounts;

- provides customers with the opportunity to share in the benefits of efficiency improvements through the ESM;

- encourages Enbridge to undertake efficiency measures at the end of the regulatory term through the SEIM. This is also to the long term benefit of customers; and

- allows Enbridge the opportunity to earn a fair return at a time when capital expenditure is significantly outside the range of historical norms that would have otherwise been difficult to accommodate on a conventional TFP-based I-X regime.

The flexibility of a Customized IR plan allows Enbridge to meet the challenges of balancing the OEB's objectives of protecting customers with regards to price and reliability and meet the needs of its shareholders. This is no easy task in the context of the very large investment projects that Enbridge plans to implement over the next few years.

5 Appendix A – References

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Ofgem (2007) 2008-13 *Gas distribution price control review – financial model for final proposals*

Ofgem (no date) *RPI-X@20 Review*, the Review's website and all supporting materials can be found at http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

National Gas Law (Australia)

National Gas Rules (Australia)

6 Appendix B – LEI relevant experience

6.1 About LEI

London Economics International LLC is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as natural gas distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

The firm also has in-depth expertise in economic and financial issues related to the electricity, gas, and water sectors, such as asset valuation, procurement, regulatory economics, and market design and analysis. LEI has worked extensively in North America, Europe, Asia, Latin America, Africa, and the Middle East, and has a comprehensive understanding of the issues faced by the utilities and regulators alike.

The following attributes make LEI unique:

- *clear, readable deliverables* grounded in substantial topical and quantitative evidence;
- *internally developed proprietary models* for electricity price forecasting incorporating game theory, real options valuation, Monte Carlo simulation, and sophisticated statistical techniques;
- *balance of private sector and governmental clients* enables LEI to effectively advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions;
- *ability to estimate relative efficiency levels* and efficiency frontiers provides expertise to advise on network tariffs and design rates under performance-based ratemaking; and
- *worldwide experience* backed by multilingual and multicultural staff.

6.2 Relevant PBR and regulatory experience in Ontario

LEI has been involved in the regulatory proceedings at the Ontario Energy Board since PBR inception. LEI has advised and provided testimony of behalf of multiple stakeholders in all of the major PBR proceedings at the OEB, including on behalf of the OEB itself on second generation PBR design, cost of capital for regulated generation assets, conservation and demand management under PBR framework, etc. LEI has also advised the Coalition of Large Distributors (third generation of electricity IRM), Ontario Power Generation (applicability of PBR to generation assets), among others, on PBR in Ontario.

6.3 PBR experience worldwide

LEI has been involved with precedent-setting PBR proceedings in Alberta (consulted ENMAX on its first formula-based ratemaking application for distribution and transmission services and FortisAlberta on its first PBR application), Middle East (development of regulatory framework for electricity, water and wastewater businesses that are not currently regulated by the national regulator in Saudi Arabia; advisory services on optimal capital structure and cost of capital for a Jordanian regulator; advisory services to distribution companies in Jordan on PBR incentives for operating costs), Europe (review of regulatory regimes in multiple jurisdictions in Europe), the Caribbean and Latin America (advised a power utility on PBR implications, advised Argentine regulator on tariff review), and Asia (advised Hong Kong regulator on regulatory regime best practices).

LEI has also been involved with a number of stakeholders (industry association, investors and operating companies) in reviewing PBR practices worldwide and their implications for the clients' operations and profitability (assisting investor to develop consensus approaches by a Romanian regulator to PBR applications, review of lease transactions involving utilities in Belgium and potential impact of PBR framework, review of PBR practices for the Canadian Electricity Association, valuation of potential acquisition targets in the US).

6.4 Gas experience

LEI has worked on a number of engagements analyzing gas transmission and distribution networks in Europe (contract review for gas transport network in the Netherlands, analysis of swap contracts involving gas transport assets in Austria) and in North America (retained by Central Research Institute of Electric Power Industry to investigate the status of deregulation in the US, reviewed barriers to entry for foreign investor looking to acquire natural gas assets in the US).

LEI has also: reviewed LNG import and export project economics over multiple projects; performed in-depth analysis of the impact of the Section 29 tax credit for non-conventional fuels production on supply and price response in US southwestern gas markets; modeled the impact of changes in the direct customer charge in Ontario on existing natural gas supply contracts with the Ontario Electricity Financial Corporation; analyzed the growing natural gas storage business in the US in the context of greater pricing flexibility, changes in storage methods and shorter-term market fluctuations; and reviewed the US gas transmission sector focusing on its regulatory structure: and on US Federal Energy Regulatory Commission ("FERC") regulatory proceedings, as well as state commission findings, related to allowed returns, capital investment requirements, and treatment of capacity.

SERVICE QUALITY REQUIREMENTS

1. The Ontario Energy Board's ("Board") Gas Distribution Access Rule ("GDAR") establishes provisions for Service Quality Requirements Performance and Measurement. The purpose of this evidence is to review the Company's filed results for the Service Quality Requirements ("SQR's") in 2011 and 2012 and discuss what action has been taken to remediate any identified gaps between certain SQRs and the Company's performance.

2. Table 1, set out below, identifies the Board's SQR targets and the Company's performance in 2011 and 2012. The paragraphs that follow address those SQRs for which the Company has not met the Board's target in 2012 and those where the Company has achieved improvements.

TABLE 1: SQR TARGETS vs ACTUALS

Service Quality Requirement	Target	2011	2012
Appointments Met Within the Designated Time Period	85.00%	95.30%	93.30%
Emergency Calls Responded within One Hour	90.00%	95.20%	96.90%
Time to Reschedule Missed Appointments	100.00%	92.80%	93.80%
Number of Days to Reconnect a Customer	85.00%	93.80%	94.10%
Call Answering Service Level	75.00%	75.20%	78.40%
Number of Calls Abandon Rate	10.00%	4.10%	2.40%
Meter Reading Performance	0.50%	0.70%	0.46%
Number of Days to provide a Written Response	80.00%	N/A	83.14%

Witnesses: L. Cowie
T. Ferguson
K. Lakatos-Hayward
M. Torriano

Appointments Met Within the Designated Time Period

3. Section 7.3.4.1 of GDAR establishes the standard for Appointments Met within the Designated Time Period (“AMWDTP”). Under Section 7.3.4.1, the distributor must track the percentage of appointments met within the scheduled time as arranged with the customer. The annual standard for AMWDTP is 85.0%. The Company’s result for 2011 was 95.3% and in 2012 was 93.3%. Scores decreased slightly over previous years as the Company introduced a process for early arrivals, which was fully implemented in 2012. The Company will drive towards improving the score now that this enhanced process is fully in place.

Time to Reschedule Missed Appointments

4. Section 7.3.4.2 of GDAR establishes the standard for Time to Reschedule Missed Appointments (“TRMA”). Under Section 7.3.4.2, the distributor must track the percentage of customers contacted to reschedule the work within two hours of the end of the original appointment time. The annual standard for TRMA is 100%. The Company’s result for 2012 was 93.8%.

5. The Company’s efforts towards meeting the TRMA target of 100% are on-going. A cross functional team meets weekly to review performance on this metric, to address issues and to re-enforce training where necessary. Regional management teams meet monthly to drive performance as well. It should be noted that the number of missed reschedules represent only 0.2% (102/46,319) of the total appointments for 2012.

6. While the Company acknowledges that promptly rescheduling missed appointments is an important part of achieving the SQR (and of customer service), attainment of a perfect 100% is not always possible. An example to demonstrate the difficulty in

Witnesses: L. Cowie
T. Ferguson
K. Lakatos-Hayward
M. Torriano

achieving 100% target would be when a technician starts running behind due to a large number of emergencies or inclement weather, there may not be sufficient time or resources, including back-office, for someone to identify that the two hour threshold is approaching and take the appropriate action to satisfy the metric. As a result, the Company recommends the TRMA target be reviewed, and set a more appropriate target of 90% to 95%. In any event, though, the Company will continue to place priority on this standard, striving to reach the current target of 100%.

7. At the same time, it should be noted that the Company has consistently exceeded the SQR targets for 2.1.9.D.1 Appointments Met within the Designated Time Period ("AMWDTP"), 2.1.9.E.1 Percentage of Emergency Calls Responded within One hour ("ECRWOH") and 2.1.9.F.1 Number of Days to Reconnect a Customer ("NDTRAC"). Exceeding these targets demonstrates the Company's commitment to and success with overall customer service. Also, by meeting more appointments, the Company reduces the absolute number of calls that require rescheduling, which promotes greater customer satisfaction.

Call Answering Service Level and Number of Calls Abandon Rate

8. Section 7.3.1.1 of GDAR establishes the standard for Call Answering Service Level ("CASL"). Under Section 7.3.1.1, the distributor must track the percentage of all calls answered within 30 seconds. The annual standard for CASL is 75%. The Company exceeded this standard in 2012 with a result of 78.4%.

9. Under Section 7.3.1.2, the distributor must track the percentage of callers who hang up while waiting for a live operator. The annual standard for NCAR is 10%. The Company exceeded this standard in 2012 with a result of 2.4%.

Witnesses: L. Cowie
T. Ferguson
K. Lakatos-Hayward
M. Torriano

Meter Reading Performance

10. Section 7.3.3.1 of GDAR establishes the standard for Meter Reading Performance (“MRP”). Under Section 7.3.3.1, the distributor must track the percentage of meters with no read for four consecutive months. The annual standard for MRP is 0.50%. The Company met this standard with a result 0.46% in 2012.

11. Gaining access to the meter is Enbridge’s single largest issue in obtaining meter readings. In winter months, it is extremely difficult to get meter reads for some of the premises in the Toronto area given the impact snow accumulation can have on the meter reader’s ability to access a meter. The Company also experiences issues in the summer in instances where a meter is installed in the backyard of a home where a gate is locked.

12. The 2011/2012 winter season was very mild in comparison to normal weather patterns with very little snow accumulation. As a result, meter readers did not have the difficulty experienced in previous years with gaining access to meters to obtain reads.

Number of Days to Provide a Written Response

13. Section 7.3.6.1 of GDAR establishes the standard for Number of Days to Provide a Written Response (“NDPWR”). Under Section 7.3.6.1, the distributor must track the percentage of customer complaints requiring a written response responded to within 10 days. The annual standard for NDPWR is 80%. The Company met this standard in 2012 with a result of 83.14%.

14. In September 2009, Enbridge implemented a new CIS. At such time, the ability to track and report on customer complaints was built within CIS so that it was visible to all customer service representatives. The reporting available in CIS, however, did

not track written responses separately. The Company was and continues to be focused on responding to all customer complaints in a timely manner. The Company implemented an enhancement to its CIS in January 2012 that has enabled it to report on the response time for written complaints.

Witnesses: L. Cowie
T. Ferguson
K. Lakatos-Hayward
M. Torriano

PERFORMANCE MEASUREMENT FRAMEWORK

Introduction

1. The purpose of this evidence is to present the Performance Measurement Framework that will be used by the Company in measuring, reporting and benchmarking performance during the Customized Incentive Regulation ("Customized IR"). The framework will provide visibility into the Company's efforts in implementing sustainable Productivity initiatives and an effective mechanism to communicate performance and outcomes over the IR term. This framework is comprised of two reporting mechanisms: (1) Productivity Initiatives Report, and (2) Performance Metrics Benchmarking Report.

Background

2. For more than 160 years, Enbridge Gas Distribution Inc. ("EGD") has been committed to delivering safe and reliable energy to customers at reasonable cost. The Company's vision is to become one of North America's leading energy distribution and services companies in delivering this commitment. To achieve its vision, the Company's strategic objectives for this year and the next three years are as follows:
    - Continued commitment to reliability and safety - the safety of Enbridge's customers, the public and its employees is Enbridge's top priority;
    - A focus on improving the customer experience - on the phone, on the web, and in the community; and
    - Improving productivity in all of Enbridge's operations.

3. Over the past decade the Company has benchmarked its performance with peer utilities across various aspects of the business. The results of these benchmarking activities have allowed the Company to understand its relative strengths and

weaknesses and incorporate this knowledge into future plans, to improve performance where possible and appropriate for our circumstances. Benchmarking results, such as the updated Benchmarking Study found within the Concentric Energy Advisors report at Exhibit A2, Tab 9, Schedule 1 and the macro-level productivity data provided in the Company's 2013 Rates Proceeding (EB-2011-0354, Exhibit JT 1.28), also give the regulator and other stakeholders a frame of reference in evaluating the Company's comparative effectiveness.

4. In the 2013 Test Year Settlement Agreement (EB-2011-0354, Exhibit N1, Tab 1, Schedule 1, p. 40), the Company acknowledged stakeholders' expectations for the tracking and reporting of productivity and efficiency gains on an initiative basis in addition to the benchmarking concept mentioned above over the next IR term. As a result, the Company is proposing a performance measurement framework to encompass both productivity initiatives reporting and benchmarking performance reporting mechanisms.

5. The proposed performance measurement framework will provide the OEB and stakeholders a reporting mechanism that demonstrates the Company's activities in pursuing productivity through operational and financial performance initiatives to maintain safety, system reliability and customer focused objectives. The Company proposes to file the Productivity Initiatives Report to the OEB annually as part of the annual Earnings Sharing Mechanism ("ESM") application**.** The Performance Metrics Benchmarking Report will be filed at end of the IR term**.**

6. The next two sections describe the objectives of the two reporting mechanisms: (1) Productivity Initiatives Report, and (2) Performance Metrics Benchmarking Report.

Witnesses: S. Kancharla
A. Mandyam
P. Squires

Productivity Initiatives Report

7. The Company proposes to track and report on productivity initiatives with an annual Productivity Initiatives Report. Included in this report will be narrative descriptions of (a) Capital Project Initiatives and (b) O&M Initiatives and the corresponding Productivity Initiatives Tracking and Reporting tables. The tables included in the report will illustrate the actual and/or avoided cost savings and efficiency gains, by initiative. The Productivity Initiatives Report will list out the challenges and pressures, where encountered, and provides a comprehensive summary into that year's results. A prototype of these tables is presented in Appendices 1 and 2 for illustrative purposes.

8. The Company proposes to file the Productivity Initiatives Report with the OEB annually as part of the annual ESM application**.** The Company is committed to providing stakeholders timely, and effective reporting and measurement by communicating the productivity performance and outcomes annually over the IR term well ahead of the subsequent rebasing application.

9. The objectives of the proposed Productivity Initiatives Report are as follows:
   (i) Establishment and maintenance of records of productivity and efficiency initiatives;
   (ii) Simplicity; and
   (iii) Visibility to linkages between initiatives and outcomes, i.e., the reports will focus on illustrating initiative's results[1] whether the results are successful or not.

[1] Measurable actual or avoided cost savings, i.e. savings that can be tracked quantitatively.

10. In terms of materiality, actual or avoided cost savings from the O&M and capital initiatives will only be tracked and reported when the cumulative cost of an initiative exceeds $1 million over the IR term.

11. Management acknowledges that the productivity initiatives pursued by the Company should not narrowly focus on generating short-term cost savings and should take into account safety and reliability risks which could lead to significant increases in costs (e.g., reducing the actual asset life span than expected). Initiatives must also avoid decreases in customer satisfaction (e.g., unplanned service outage, leakage) over the medium and long term. Therefore, in determining the productivity and efficiency initiatives that will be pursued over the incentive regulation term, Management has established the following guiding principles:
    i. Efficient and effective use of resources;
    ii. Doing things right (efficient) and doing the right things (effective);
    iii. Sustainable savings over multiple periods; and
    iv. Optimal balance between effort and outcomes that are valued by stakeholders, e.g. safe and reliable energy supply at a reasonable cost.

12. As stated in Exhibit A2, Tab 1, Schedule 2, the Company has made significant strides in pursuing productivity initiatives during the previous IR term. As a result, the opportunity for incremental productivity savings in coming years may be limited. That being said, the Company will have to find productivity savings to operate within its proposed O&M Budgets. Examples of expected or possible productivity initiatives are set out in the O&M and Capital Budget evidence.

13. At Exhibit A2, Tab 11, Schedule 3, Enbridge has proposed a Sustainable Efficiency Incentive Mechanism to apply during the customized IR term. This mechanism will

provide Enbridge with incentives to implement initiatives that will result in sustainable productivity gains beyond the rebuilding year. The reporting and evaluation of these initiatives will be done using the Productivity Initiatives Report.

Performance Metrics Benchmarking Report

14. The purpose of the Performance Metrics Benchmarking Report is to compare actual results of the Performance Metrics stated in Appendix 3, and described over the next several pages, with either the industry average or best practices from other gas utilities. The purpose of the benchmarking is to compare the metrics relative to comparable peer companies in terms of direction and trending. Results from the benchmarking comparison may be used as inputs to further inform improvements or adopt specific best practices from gas utilities that have similar operations to EGD's, as appropriate.

15. Included in this Benchmarking report will be narrative descriptions of the metrics, results, and the corresponding Benchmarking comparison table. The table included in the report will provide EGD's results, industry average results, and EGD's ranking relative to the industry based upon reputable external benchmarking publications, such as that produced by Concentric Energy Advisors Inc. or the American Gas Association. A prototype of this table is presented in Appendix 4 for illustrative purpose.

16. Appendix 3 presents the Performance Metrics that will be used to measure the outcomes of the Company's strategic objectives mentioned on page 1. These outcomes are organized in the following three categories or dimensions:
    (i) Customer Relationship

(ii) Operational Performance

(iii) Financial Performance

17. The metrics reported in Appendix 3 are measurable, relevant and attainable output indicators or result metrics which reflect the outcomes of the Company's strategic objectives. The corresponding implementation costs[2] would not outweigh the value of these metrics. In addition, they are currently the standard measures supported or published by reputable external benchmarking publications. Consequently, the Company is able to benchmark these metrics relative to comparable peer companies.

18. These outcome based metrics will help inform improvement at the operational and customer service level, and demonstrate that the Company is on track to reach strategic objectives. To the extent that the Company's strategic objectives are revised to reflect changing business conditions, the corresponding performance metrics may also be updated accordingly. For similar reasons, if the metrics are no longer supported by the benchmarking publications in the future, these metrics will be replaced with the next best available measures.

19. The objective in the Customer Relationship dimension is to be recognized by customers as the best utility service provider in North America. This objective can be achieved by ensuring that services are provided in a way that responds to customer preferences and achieves the established service quality requirements. As a result, the Company will continue to invest in improvements to the customer experience. Please refer to Exhibit D1, Tab 15, Schedule 1, regarding Business

[2] Examples of the implementation costs are hiring additional employees, developing new systems or applications, efforts and expenses in collecting and compiling data, membership or subscriptions fees, etc.

Development and Customer Strategy Department's mandate and responsibilities. In order to assess the Company's progress, the following metrics are monitored regularly:

(i) Customer Experience: Customer Satisfaction Index - The Index will be compared against comparative North American gas utilities.

(ii) Service Quality Requirements Performance and Measurement Metrics (SQR):

   (i) Telephone Answering Performance: Call Answering Service Level
   (ii) Gas Emergency Response: Percentage of Emergency Calls Responded to Within One Hour
   (iii) Meter Reading Performance: Meter Reading Performance Measurement
   (iv) Service Appointment Response Time: Appointments Met Within the Designated Time Period
   (v) Service Appointment Response Time: Time to Reschedule a Missed Appointment
   (vi) Reconnection Response Time: Number of Days to Reconnect a Customer
   (vii) Customer Complaint Written Response: Number of Days to Provide a Written Response
   (viii) Telephone Answering Performance: Abandon Rate

These metrics have been established by the OEB to track the gas utility's service quality performance. Please refer to Exhibit A2, Tab 11, Schedule 1, for further discussion on these SQR metrics' definitions. The OEB's annual publication, Yearbook of Natural Gas Distributors, presents the results filed by the three gas utilities in Ontario.

Witnesses: S. Kancharla
A. Mandyam
P. Squires

20. In the Operational Performance dimension, the Company is looking to enhance safety, system integrity, productivity, and operational excellence to achieve best in class work practices. As the safety of Enbridge's customers, the public and its employees is always Enbridge's top priority, the Company will continue to invest and operate in a manner that provides safe and reliable energy supply at a reasonable cost, and increases productivity (efficiency and effectiveness) in all of the operations. Please refer to Exhibit B2, Tab 1, Schedule 1, for specific initiatives and plans. In order to assist in the assessment of progress in this area, the following metrics will be tracked:
    (i) Integrity Management - Damage Prevention: Number of Excavation Damages per 1,000 Locates
    (ii) Integrity Management - Leak Management: Service Leaks Repaired per Mile of Service[3]
    (iii) Integrity Management - Leak Management: Total Number of Grade 1 (A) leaks[4] repaired during the year
    (iv) Operational Effectiveness: Number of all outages per 1,000 Customers[5]
    (v) Employees Health and Safety: Total Reportable Injury Frequency Rate

21. In the Financial Performance dimension, the Company's objective is to maintain an effective financial discipline to deliver customer and shareholder value. As demonstrated in the Benchmarking Report prepared by Concentric in this case. EGD has historically been an industry leader in terms of operating efficiently and managing its O&M costs. Further efforts will be pursued during the Customized IR

[3] EGD tracks service leaks repaired per km of service. In order to be consistent with the benchmarking publication, this metrics is converted to per mile of service using the standard conversion.
[4] A Grade 1 leak is a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.
[5] Outage is defined as any time there is an unplanned loss of gas service.

plan term to improve efficiency and effectiveness. The following metrics are the traditional ones used to provide a balanced view of the Company's financial performance:

(i) Financial Efficiency: Operating and Maintenance Cost per Customer

(ii) Return on Equity

(iii) Financial Obligations Met: Interest Coverage Ratio

Conclusion

22. In conclusion, the performance measurement framework presented in this evidence is comprised of two reporting mechanisms: (1) Productivity Initiatives Report, and (2) Performance Metrics Benchmarking Report. These mechanisms will provide visibility into the Company's efforts to operate the business cost-effectively. The combination of annual reporting via the Productivity initiatives report and the end of term Benchmarking Report is Management's commitment to demonstrating cost-effective operation of the business over the next incentive regulation term.

Witnesses: S. Kancharla
A. Mandyam
P. Squires

Appendix 1: Capital Project Initiatives – Productivity Initiatives Tracking and Reporting Table (Sample, for Illustrative Purpose)

Capital Cost Savings:

Initiatives ($ Millions)	2014	2015	2016	2017	2018	2014-2018 Total
Relocation of the Meter Shop to A Leased Property – Avoided Capital Savings in Future Leasehold Improvements	$0.1M*	$0.2M*	$0.3M*	$0.4M*	$0.5M*	$1.5M*
Initiative B, etc.						
Total	$0.1M*	$0.2M*	$0.3M*	$0.4M*	$0.5M*	$1.5M*

* These numbers are for illustrative purpose.

Witnesses: S. Kancharla
A. Mandyam
P. Squires

Appendix 2: O&M Initiatives – Productivity Initiatives Tracking and Reporting Table (Sample, for Illustrative Purpose)

O&M Cost Savings Table:

Initiatives ($ Millions)	2014	2015	2016	2017	2018	2014-2018 Total
Bill 8 Ontario One Call's Mandated Locate Requests – Future Savings of Reducing Third Party Excavation Damages	$0.1M*	$0.2M*	$0.3M*	$0.4M*	$0.5M*	$1.5M*
Initiative B, etc.						
Total	$0.1M*	$0.2M*	$0.3M*	$0.4M*	$0.5M*	$1.5M*

* These numbers are for illustrative purpose.

Appendix 3: Benchmarking Report - Performance Metrics

Customer Relationship	Operational Performance	Financial Performance
EGD will strive to be recognized by customers as the best provider of utility services in North America.	***Continuous improvement in safety, system integrity, productivity, and operational excellence. Achieve best-in-class work practices.***	***Effective financial discipline to deliver customer and shareholder value.***
• Customer Experience: Customer Satisfaction Index	• Damage Prevention: Number of Excavation Damages per 1,000 Locates	• Financial Efficiency: O&M cost per customer
• Call Answering Service Level (SQR)	• Leak Management: Service Leaks Repaired per Mile of Service	• Profitability: Return on Equity
• Percentage of Emergency Calls Responded to within One Hour (SQR)	• Leak Management: Total Number of Grade 1 (A) leaks eliminated or repaired during the year	• Financial Obligations Met: Interest Coverage Ratios (Legal Entity)
• Meter Reading Performance Measurement (SQR)	• Operational Effectiveness: All outages per 1,000 Customers	
• Appointments Met within the Designated Time Period (SQR)	• Employees Health and Safety: Total Reportable Injury Frequency Rate	
• Time to Reschedule a Missed Appointments (SQR)		
• Number of Days to Reconnect a Customer (SQR)		
• Number of Days to provide a Written Response (SQR)		
• Number of Calls Abandon Rate (SQR)		

Witnesses: S. Kancharla
A. Mandyam
P. Squires

Appendix 4: Benchmarking Comparison Table (Sample, for Illustrative Purpose)

Number of Excavation Damages per 1,000 Locates	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
EGD	3.0*	2.6*	2.2*	1.9*	1.9*	1.9*
AGA Industry Average	4.5*	4.4*	4.3*	4.3*	4.3*	4.3*
AGA Benchmarking Comparison	4th Quartile*	4th Quartile*	3rd Quartile*	3rd Quartile*	3rd Quartile*	3rd Quartile*

* These numbers and ranking comparison are for illustrative purpose.

UPDATED SUSTAINABLE EFFICIENCY INCENTIVE MECHANISM (SEIM)

1. This updated evidence modifies and replaces the Sustainable Efficiency Incentive Mechanism ("SEIM") as originally proposed. The modifications to the SEIM proposal respond to various criticisms from stakeholders of the originally proposed SEIM. The modified SEIM will directly incent the Company to find further opportunities for projects that result in sustainable efficiencies by applying an Efficiency Carryover Mechanism ("ECM"). Notwithstanding the changes to the form of the SEIM, the title of the mechanism remains appropriate, as this tool is intended to provide incentive to Enbridge to find and take advantage of sustainable efficiency and productivity opportunities throughout the IR term, with benefits that will extend beyond the term of the IR plan.

2. As explained herein, the updated SEIM that the Company is proposing balances the goal of incenting the utility to find and take advantage of sustainable efficiency initiatives with measures to protect customers by ensuring that Enbridge only receives a reward where its performance merits a reward. The SEIM reward will only be available where EGD can demonstrate that the value of the efficiency initiatives undertaken exceed the amount of the reward, and where EGD can demonstrate that it has maintained strong service and operations through the IR term. Additionally, the SEIM reward will not apply until after rebasing, and there will be a cap on the amount of the SEIM reward that is available.

Background

3. As explained in Exhibit A2, Tab 1, Schedule 2, the Company has incorporated productivity savings into its forecast capital and O&M costs that underlie the requested Allowed Revenue amounts. As a result, the Company will have to find

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

ways to achieve significant productivity savings in order to earn its Allowed ROE over the term of the plan. In addition, the Company is strongly incented to manage to the forecast cost levels in the face of many uncertainties and the cap on Allowed Revenue.

4. To further enhance the incentives within this Customized IR plan for Enbridge to find and achieve sustainable productivity gains (rather than short-term cost savings), the Company is proposing this updated SEIM. The updated SEIM adds an incentive for Enbridge to invest in productivity throughout the Customized IR term. This mechanism is well-aligned with the long-term nature of utility investments and programs.

5. By creating the right incentives, the SEIM is expected to produce benefits for both ratepayers and shareholders. Ratepayers will benefit from the fact that the Company's costs (and ultimately rates) will be lower than they otherwise would be beyond the rebasing year. The Company will benefit through an incentive payout in the years following the end of the Customized IR plan term. Similarly, the SEIM will remove a disincentive for the Company to continue to invest in productivity enhancements, should they exist, in the later years of the IR term.

<u>Context for Redesigned SEIM</u>

6. EGD discussed the SEIM at the October 11th Stakeholder Information Session. At that time, a number of questions and criticisms of the SEIM were presented to Enbridge. Some of these can also be seen in Interrogatory questions. Pacific Economics Group Research also provided commentary on the SEIM. The criticisms of the SEIM as originally proposed include the following items:

a) The amount of the SEIM payout is based on estimated and projected benefits forecast into the future with no way to validate the forecast benefits
b) The SEIM payout is an annual reward during the IR term
c) There is no cap to the SEIM payout

7. At the Stakeholder Information Session, EGD indicated that it was prepared to take away the comments received, and consider whether a different approach to the SEIM is appropriate. EGD has done so.

8. In re-formulating the design of the SEIM, the Company has further reflected on the intent of mechanism. To recap, the mechanism is intended to:
   - Create stronger incentives within the IR plan
   - To create the incentives in such a way that they relate directly to long-term, sustainable efficiencies that will provide benefit to customers
   - To provide a direct link to the OEB's objective for driving sustainable efficiencies during IR

9. In designing a mechanism to address these objectives, the Company has considered other mechanisms that have been either proposed or approved in other jurisdictions. Specifically, EGD looked at the Efficiency Carryover Mechanism ("ECM") proposal made by FortisBC in British Columbia and the ECM adopted by the Alberta Utilities Commission ("AUC") in Alberta. The Company received assistance from London Economics International ("LEI") in the development of the updated SEIM including ideas for what should be included in the mechanism and information about similar mechanisms in other countries, such as Australia and the U.K. Attached as Appendix A are brief comments from LEI about the modified SEIM proposal.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

10. EGD considered the information about similar mechanisms in other jurisdictions in conjunction with the intentions of the mechanism (as listed above) to develop its modified SEIM proposal.

11. The ECM that has been proposed in BC relates to FortisBC Energy Inc. That ECM would calculate net O&M and Net Plant savings by year of the IR plan term, which would then be shared equally between ratepayers and shareholders and summed over a rolling 5-year time horizon.[1] The application containing this request is ongoing, and there is no decision from the BC regulator.

12. The most relevant Canadian example that EGD reviewed is from Alberta. The Alberta Utilities Commission ("AUC") approved an ECM as proposed by ATCO Gas as part of the Rate Regulation Initiative.[2] Under that proposal, the ECM would be calculated as an add-on to the Approved ROE for up to two years following the term of the IR plan. The add-on would be equal to one half of the difference between the average ROE achieved over the term of the IR plan and the average approved ROE over the IR term. If the difference is positive, then that difference would be multiplied by 50%, and then the lessor of that result or 0.5% would apply as a premium to the Approved ROE for 2 years after the term of the IR plan.

13. In approving the ECM mechanism, the AUC commented as follows:

> 775. The Commission agrees that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects. The Commission finds that the incentive

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[1] FortisBC Energy Inc., Application for Approval of Multi-Year Performance Based Ratemaking Plans for 2014 through 2018: http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/130610_FEI_2012-2018_PBR_Application_Volume_1.pdf .

[2] Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance Based Regulation, September 12, 2012

Witnesses: R. Fischer
S. Kancharla
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P. Squires

> properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term. The Commission agrees with ATCO's proposal for an upper limit for earnings that can be carried over and finds the limit of 0.5 per cent to be reasonable. Accordingly, the Commission approves the ATCO companies' ROE ECM for inclusion in the ATCO companies' PBR plans. If any of the other companies wish to submit the same ECM in their PBR plans, they may do so in their compliance filings.[3]

14. The Company agrees with the intent of an ECM, as articulated by the AUC. EGD notes that the intent of the Alberta ECM is to strengthen incentives for utilities' IR plans. More specifically, this type of mechanism is intended to reduce the disincentive for a utility to invest in the latter years of an IR plan. That disincentive arises, ultimately, because the benefits to be derived by the productivity investment will be clawed back for the benefit of ratepayers at rebasing. As such, with a shorter duration for enjoyment of the benefits (i.e., in the latter years of the plan) the incentives for the utility to invest in productivity-enhancing initiatives is weakened. In some cases, this could lead to a situation where full recovery of the costs of the productivity-enhancing investment would not be achieved during the term of the IR plan.

15. The Company does note, however, that there may be some issues with the FortisBC and Alberta mechanisms that wouldn't necessarily correlate with the objectives for a SEIM as laid out above.

16. There are two main issues with the FortisBC proposal as EGD sees it. The first is that the mechanism doesn't directly incent long term efficiencies, and in fact, may strengthen the incentive to undertake short-term, temporary, cost cutting. That is, the utility would be able to simply defer costs until rebasing and still stand to gain an

[3] Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance Based Regulation, September 12, 2012, at para. 775.

ECM reward. A second issue arises in that the design of the mechanism may be seen to reward over-budgeting.

17. EGD also sees an issue with the ECM as it has been adopted by the AUC. The trigger for determining whether an ECM payout is due is not linked with achieved productivity gains. Both the amount of the Alberta ECM reward, and whether the award is merited, are based solely on historical earnings (a comparison of actual ROE to approved ROE) which may or may not have any bearing on long term, sustainable benefits. The fact that a utility has achieved an ROE in excess of the Board-approved level may or may not be related to productivity gains. That is to say that excess historical earnings may have arisen due to factors beyond the utilities' control, or that aren't related to long term ratepayer benefits. Again, this would contradict the Ontario objective of fostering sustainable efficiency gains.

18. EGD believes that an appropriately designed ECM/SEIM should contain measures that condition the receipt of the reward on actual performance and sustainable efficiency programs undertaken by the utility.

<u>The Modified SEIM: EGD's Proposal</u>

19. In the paragraphs that follow, EGD presents the concept of the updated SEIM proposal and describes how the process would work. EGD also addresses how this updated proposal addresses the criticisms of the originally filed SEIM, and how this proposal meets the Board's objective for incenting activities that produce long term, sustainable benefits.

20. The modified SEIM proposal will consist of the following:

i EGD may make a one-time application for a SEIM reward in the rebasing year.

ii Similar to the Alberta ECM, the amount of the available reward will be a function of the difference between EGD's actual and allowed ROE during the term of the plan, as follows:

- the form of the reward will be a premium on the ROE used for rates for up to two years beyond the term of the plan (i.e. rebasing year and the next); and
- there would be a cap of 0.5% ROE per year on the reward

iii However, the SEIM reward will only be available to EGD if it can justify that:

- the net present value (NPV) of the long term benefits to ratepayers from EGD's sustainable productivity initiatives undertaken during the IR term are greater than the available award, and
- the utility's quality of service during the IR period has stayed at or above the current level.

iv The SEIM process will contain three basic steps, to be undertaken within EGD's rebasing application (assumed to be in 2018 for 2019):

- Step 1: Determine the reward potential
- Step 2: Demonstrate that the reward is justified
- Step 3: Apply the reward, if applicable

21. These three steps are described further below.

Witnesses: R. Fischer
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M. Lister
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P. Squires

Step 1: Determining the Reward Potential

The amount of the SEIM reward that is available is based on a comparison of EGD's average actual ROE for each year of the IR term compared to the Board-Allowed ROE for each year. The actual ROE to be used will be calculated in the same way as actual ROE is determined for ESM purposes. This SEIM reward (which will operate as a premium on the ROE that applies to rates for the rebasing year and the following year) will be equal to one half of the difference between the average ROE achieved during the IR term and the average Allowed ROE over the term of the plan. If the difference is positive, then that difference would be multiplied by 50%, to create a SEIM reward. The SEIM reward for each of the two years will be capped at a maximum of 50 basis points above the Allowed ROE.

Mathematically, the Reward Potential could be presented as follows:

> SEIM Reward Potential (ROE Premium) for each of 2019 and 2020= [Average Actual ROE (2014-2018) – Average Allowed ROE (2014-2018)]*50%*50%
>
> ROE Premium=Min[Reward Potential, 0.5%] (the lesser of the Reward Potential or 0.5%)

As a final step for this stage, the ROE premium will be expressed as a dollar amount, based on the forecast rate base level for 2019. This dollar amount (multiplied by two) will be used for the purpose of justifying the reward in the next step.

Witnesses: R. Fischer
S. Kancharla
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P. Squires

Step 2: Demonstrating that the reward is justified

To qualify for the SEIM reward, EGD must show that the NPV of the long-term benefits generated by any productivity initiatives undertaken during the IR term are greater than the reward. The Company must also show that its service and performance have been maintained at or above the current level. The data and information used to make this determination would consist of the following items:

1. EGD will have to show that the NPV of the expected benefits from productivity initiatives undertaken during the IR term is greater than the dollar amount associated with the SEIM reward. The information to be used for this exercise will be included within the Productivity Initiatives Reports that are to be filed each year during the IR term (see Exhibit A2, Tab 11, Schedule 2). Within those reports, EGD will provide details of the projects, a description of how multi-year benefits accrue as a result of the projects, information about how the project costs were determined, and the details and assumptions used to estimate the long-term multi-year benefits anticipated from the projects. The NPV of the net benefits will be determined using the same financial parameters (capital structure, costs of capital, tax rates, etc.) as are used for customer additions feasibility analysis.

2. EGD will produce a Performance Metrics Benchmarking Report, as described at Exhibit A2, Tab 11, Schedule 2, which will set out the results of EGD and the industry average in relation to metrics around Customer Relationship and Operational Performance. To be permitted to recover the SEIM reward, EGD will need to establish that on average over the IR term, the Company has been able to maintain or improve its performance in these areas.

Witnesses: R. Fischer
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P. Squires

3. Included within the Performance Metrics Benchmarking Report will be a reporting of EGD's Service Quality Requirements (SQR) performance over all years of the IR plan. To be permitted to recover the SEIM reward, EGD will need to establish that its overall SQR performance is maintained at or above the 2013 level for at least three of the five years of the IR term.

In the event that EGD seeks a SEIM reward for 2019 and 2020, the Company will include all of the above information within its rebasing application. Stakeholders will be free to take any position challenging any of the information brought forward or any other information challenging EGD's entitlement to the SEIM reward.

i Step 3: Applying the Reward

If EGD is successful in establishing its entitlement to a SEIM reward (ROE premium), then the reward would be administered within the 2019 rebasing case and the 2020 rates case, as follows:

SEIM Reward = 2019 Utility Rate Base * Utility Equity Ratio * ROE Premium

This amount would be added to the Revenue Requirement in the rebasing year for collection in that year. The same amount would be applied in the 2020 rates proceeding.

22. To provide further illustration of EGD's updated SEIM proposal, examples are provided below.

Witnesses: R. Fischer
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P. Squires

Example 1:

- *Step 1*:

  Average Actual ROE = 9.5%

  Average Allowed ROE = 10.0%

  Reward Potential = (9.5% - 10.0%) = -0.5%

  EGD does not qualify for the reward.

Example 2:

- *Step 1*:

  Average Actual ROE = 10.5%

  Average Allowed ROE = 10.0%

  Reward Potential = (10.5% - 10.0%) = 0.5% * 50% * 50% = .125%

  ROE Premium = Min[0.125%, 0.5%] = 0.125%

  The ROE Premium would then be converted into a dollar amount.

  2019 Utility Rate Base * 2019 Utility Equity Ratio * 0.125%.

  Assume 2019 Utility Rate Base = $4 billion

  Assume 2019 Equity Ratio = 36%

  Therefore, the dollar value of the ROE premium for 2019 would be $1.8 million (4 billion * 36% * 0.125%).

  The same amount would be applied for 2020.

- *Step 2*:

  EGD will file information to establish entitlement to the SEIM reward.

Witnesses: R. Fischer
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The data from the Productivity Initiatives Reports will have to demonstrate that the net present value of benefits from sustainable efficiency gains undertaken during the IR term exceeds $3.6 million.

EGD will also have to establish, through the Performance Metrics Benchmarking Report, that it has at least maintained its current Customer Relationship and Operational Performance levels over the IR term and has not experienced material shortcomings in overall SQR performance over the IR term.

- *Step 3*:
  If EGD successfully meets all thresholds above, then a reward of $1.8 million would flow to EGD for each of 2019 and 2020.

Conclusion

23. EGD believes that the redesigned SEIM achieves the goals of the mechanism more effectively, and address concerns raised by stakeholders. The goal of the SEIM is to produce incentives for management to undertake long-term, sustainable efficiencies. In particular, through the “carrot” of the potential SEIM “reward” at re-basing, the SEIM will encourage management to pursue initiatives where benefits may accrue beyond the term of the IRM cycle, which would exclusively benefit customers

24. The redesigned SEIM addresses each of the criticisms from stakeholders that were noted above :
    a) The SEIM reward is no longer calculated based on future unverified benefits

Witnesses: R. Fischer
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i) The SEIM reward is now calculated based on Enbridge's financial performance during the IR term, however,

(1) EGD will still have to establish that the NPV of the benefits to be achieved from sustainable productivity initiatives will be greater than the amount of the SEIM reward

(2) The reward will also be contingent on other demonstrated performance factors (i.e. ROE performance, Benchmarking performance, SQR performance)

b) The SEIM payout will no longer be an annual reward during the IR term

i) The modified SEIM is a one-time reward (if applicable) to be assessed for the rebasing year and the next year

c) There will be a cap on the amount of the SEIM reward payout

i) The modified SEIM sets out a maximum of a 0.5% ROE adder, but only if the long term ratepayer benefits exceed the reward sought.

25. Enbridge acknowledges that, at least in part, the modified SEIM will still be premised in part upon a quantification of future benefits from sustainable efficiency initiatives. The Company believes that this is the only viable way to implement the SEIM in a straightforward manner. It is not feasible to expect that projections of future financial benefits from efficiency gains will be validated at a future date in order to make adjustments to SEIM reward payments. The fact is that some productivity initiatives may have benefits that are forecast to run for three, five, ten or more years into the future. If the validation of such benefits is a requirement, then the SEIM for 2014 to 2018 would not be finalized until all the benefits have run their full course, which may be upwards of 10 years. This is clearly not feasible. Another option for validation would be to hire a 3rd party to conduct the validation, as occurs in the Demand Side Management evaluations. However, in the

Company's opinion, this creates layers of bureaucracy and administration that outweigh the benefit. That said, there will be an opportunity for the Board and stakeholders to review and comment on the Company's evidence around the productivity initiatives undertaken during the IR term and the associated NPV.

26. The Company believes that the updated SEIM proposal creates the right incentives, but conditions the reward on the justification of long term benefits to ratepayers, as opposed to mere reliance on historical earnings, which may or may not have any bearing on long term sustainable efficiencies. This proposal starts by adopting the ESM mechanism that was approved in Alberta (and characterized as "an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects"), and then evolves and improves the mechanism for use in an Ontario context.

27. EGD believes that the modified SEIM laid out in this proposal meets the objectives of the OEB:
    - Ties SEIM reward to ROE performance and provides the utility with an ongoing incentive to operate efficiently throughout the entire IR term
    - Includes stronger incentives for creating sustainable efficiencies, by removing a disincentive for productivity investment in later years of the IR plan
    - Creates the incentives in such a way that they relate directly to long-term, sustainable efficiencies that will provide benefit to customers
    - Provides a direct link to the OEB's objective for driving sustainable efficiencies during IR.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

Evaluation of Enbridge Gas Distribution's updated Sustainable Efficiency Incentive Mechanism

Prepared by London Economics International ("LEI") for Enbridge Gas Distribution Inc. ("EGD")

December 11th, 2013

Enbridge Gas Distribution Inc. ("EGD") updated its proposed Sustainable Efficiency Incentive Mechanism ("SEIM") in response to the suggestions and comments from stakeholders on the originally proposed SEIM. LEI reviewed the updated SEIM and finds that the updated SEIM meets the objectives of the Ontario Energy Board ("OEB" or the "Board") and is consistent with the principles of an efficiency carryover mechanism ("ECM"). Furthermore, the updated SEIM addresses concerns raised by Stakeholders and incorporates features that would strengthen the utility's incentives to seek out and implement sustainable longer term incentives, even at the end of the Incentive Regulation ("IR") term.

1. Updated SEIM addresses concerns raised by Stakeholders

As described in the updated SEIM filed by EGD under Exhibit A2, Tab 11, Schedule 3, EGD modified its proposed SEIM to respond to various criticisms from stakeholders of its original SEIM, including yearly reward of the SEIM payout during the IR term, no cap on the SEIM payout, and SEIM payout based on forecasted or estimated benefits rather than actual benefits.

To address these concerns, EGD is incorporating the following new features in its updated SEIM:

- the SEIM is now calculated **based on EGD's performance during the IR term** and not on future undertakings;
- EGD has the **burden of proof** to show that it deserves the reward by demonstrating that the benefits of the initiatives to customers outweigh the costs to customers of the SEIM reward. In addition, the SEIM has safeguards against short-term cost reductions that may undermine service quality. In the request for SEIM award, the utility will demonstrate that service quality was not degraded and that it has at least met or exceeded performance targets; and
- there is a **cap** on the SEIM reward which mitigates some of the cost increase exposure to customers at re-setting and is consistent with goal of managing rate volatility.

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2. Updated SEIM meets the OEB objectives

Given the concerns raised by stakeholders, LEI evaluated how the updated SEIM meets the Board's objectives. LEI finds EGD's updated SEIM consistent with the objectives of the OEB as discussed below.

- ***Protect consumers in respect of price and reliability:*** consumers are protected because EGD will only receive an SEIM reward if it can demonstrate that the net present value ("NPV") of the benefits to consumers of the programs or initiatives undertaken are greater than the amount of the reward. In addition, EGD has to prove that it had performed over the term of the IR plan consistent with its overall Service Quality Requirements ("SQR"). This ensures that any reductions in costs are not made at the expense of service quality. Furthermore, there is a cap to the amount of reward that EGD can receive under the SEIM. The two-year payout window of the reward also protects consumers from rate volatility.

- ***Encourage efficient utility***: the goal of the updated SEIM, similar to the goal of the original SEIM, is to produce incentives for management to undertake long-term sustainable efficiencies, and to reduce the potential motivations for management to otherwise delay efficiency-enhancing projects at the end of the IR term. In particular, through the "carrot" of the potential "reward" on the next term, the SEIM will encourage management to pursue initiatives where benefits may accrue beyond the term of the current IR plan.

- ***Quality of service***: SEIM ensures that EGD maintains or exceeds its current service performance as EGD will only receive the reward if it can demonstrate that it was able to do this for at least three of the five years of the IR term.

- ***Industry financial viability***: SEIM will not undermine EGD's viability. The rewards to the updated SEIM are in line with the risks that EGD is taking in the other elements of the IR Plan. For example, EGD's IR plan has an asymmetric earnings sharing mechanism ("ESM") which will not shift any risk of under-delivery of productivity gains to customers. Moreover, as a complement to the risks that EGD takes on, the SEIM reward would not be paid if the average actual return on equity ("ROE") is below the average allowed ROE for the IR term.

3. Updated SEIM is consistent with the common characteristics of an ECM

LEI had reviewed the experiences of other jurisdictions that rely on building blocks approach to incentive ratemaking. The updated SEIM is in line with ECMs used in other jurisdictions. LEI reviewed the ECMs currently being implemented in Alberta, and the ECMs that have been used

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in Australia and the UK. Please see the Appendix (on page 4) for the comparative table of the differences and similarities of these other jurisdictions' ECMs and EGD's updated SEIM.

Based on our knowledge of other implemented ECMs and the Customized IR plan that EGD has proposed, it is our opinion that the updated SEIM possesses all the core features of a generic ECM:

First, an ECM should provide the utility with an **ongoing incentive to operate efficiently throughout the entire regulatory period**. This is to address the issue that the utility will target efficiency gains in the early years of a regulatory period only. The SEIM award provides the incentive to management, as it will be a material payment, if it is approved by the Board on review of the SEIM application. At the same time, the SEIM award would only be paid if the utility can demonstrate that it has taken initiatives that have produced and will produce a stream of benefits to ratepayers that exceed the SEIM award. Therefore, the SEIM award is tied directly to productivity undertakings by the utility.

Second, the ECM should **allow a utility to carryover the incremental earnings from efficiency gains into the next regulatory period**. Under the updated SEIM, the reward will be carried over in the first two years of the next term (or 2019 and 2020). This is similar to the payout system of the Alberta's ECM.

Third, an ECM should **only target efficiency gains** and not apply to windfall gains or other unexpected cost savings. To ensure that the SEIM reward is not based on cost reductions due to factors external to the business like lower interest rates, EGD's updated SEIM requires that the utility demonstrate that the reward is justified. This is done by showing that the NPV of the expected benefits from the initiatives performed during the IR term is greater than the payment of the SEIM reward. In addition, EGD has to show that, on average over the 5-year period, it has been able to maintain or exceed its performance listed in the Performance Metrics Benchmarking Report. Lastly, EGD has to prove that it has maintained SQR performance at or above the 2013 level for at least three of the five years of the IR term.

Lastly, an ECM should **reward utilities after they have achieved efficiency gains**. With the updated SEIM, EGD will be rewarded only after efficiency initiatives have been implemented. Although the benefits of those efficiency initiatives may flow to customers for some time, the Board and stakeholders will have the benefit of knowing specific initiatives that have led to those benefits.

Overall, the updated SEIM generates sustainable, multi-year incentives and is consistent with well-designed ECMs.

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4. Appendix: Comparative review of SEIM with carryover mechanisms in other jurisdictions

Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
Alberta *(ROE ECM)*	**Amount of Reward**: Difference between average approved ROEs and average actual ROEs for the prior) regulatory period. **Calculated Features of the Reward**: - partial true up (50%); - only positive differences in ROEs; and - reward cap of 0.5%. **Timing of Payment and Payment Period of Reward**: The SEIM Reward will be paid out over a two year timeframe after the end of the IR term, such that the payout can effectively motivate management to continue to carry out efficiency-enhancing projects at the end of the IR term.	**Basis for Reward:** EGD is proposing to base the reward on an analysis of benefits to consumers from achieved and future efficiency gains, therefore such benefits need to exceed the reward amount. In Alberta, the ECM was triggered on the basis of ROE overearnings, without the need for substantiating the productivity achieved and without the review of specific initiatives that improved productivity.	- AUC Decision 2012-237 (September 12, 2012)
Australia *(Opex Efficiency*	**Basis for Reward:** EGD is proposing to document	**Calculation of Reward**: EBSS calculates the carryover rewards based	- AER (November 2013) *Better Regulation: Efficiency*

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Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
Benefit Sharing Scheme for Electricity Network Service Providers mechanism)	achieved productivity gains. Likewise, EBSS is also awarded if there is improvement in operating expenditure ("opex") performance. **Timing of Payment of Reward**: Rewards will be awarded on the next regulatory period. **Risk/Reward:** EBSS has both rewards and penalties; rewards are shared with customers at a ratio of about 30% for utilities to 70% for customers. Likewise, EGD's SEIM reward is consistent with the risks that EGD is taking in the other elements of the IR plan. EGD is already taking the risks in its proposed asymmetric ESM, where under-performance is solely the financial responsibility of utility management and shareholders. In addition, the SEIM reward is authorized only if EGD's financial	on difference between forecasted and actual opex, while EGD (for simplicity) is using the difference in actual and allowed ROEs. **Payment Period of Rewards**: EGD is proposing a two-year payout for the next term while EBSS involves rolling where the carryover period is currently set as five years.[1]	*Benefit Sharing Scheme for Electricity Network Service Providers.*

[1] If IR term is not equal to 5 years, AER may decide to change the carryover period.

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Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
	performance exceeds expectations (in other words, if average actual ROE exceeds allowed ROE).		
UK (*Carry-over mechanism for network output measures ("NOM")*)	**Basis of Reward (period):** Performance ***over the whole IR term*** is used to determine carry-over/catch-up for the next IR term. **Timing of Payment d of Reward**: Rewards will be awarded on the next regulatory period. **Risk/Reward:** NOM Carryover has reward of 2.5% of additional costs of material over-delivery, and penalty of 2.5% of avoided costs of material under-delivery. Similarly, EGD's SEIM reward is consistent with the risks that EGD is taking in the other elements of the IR plan. EGD is already taking on risks of under-performance in its proposed	**Calculation of Amount of Return:** While SEIM uses actual and approved ROEs, UK's NOM Carryover is based on achievement of target "Outputs" based on what is set by Ofgem at the start of the regulatory period. (Note: "Outputs" include performance metrics in such areas as asset health, asset load/capacity utilisation, secondary deliverables, as well as safety). **Calculation of Reward**: UK compares target and actual NOMs; carry-overs (awards) or catch-ups (charges) are estimated if actual NOMs are not on target. The payout under the NOM Carryover is based on the "estimate [of] the costs associated with the under or over delivery against the NOMs target… based on the	- Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation.*

Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
	asymmetric ESM. Furthermore, the SEIM reward would be approved only if the average actual ROE exceeded the average allowed ROE for the term of the IR plan.	underlying asset volume and relevant unit costs."[2] **Payment Period of Reward**: While SEIM's reward is proposed to be paid out in two years for the next term, the carryover for NOM is paid out for entire next term (which is currently set as 8 years).	

[2] Ofgem. *RIIO-GD1: Final Proposals - Supporting Document – Outputs, incentives and innovation*. December 2012, pp. 68-70. Available online at https://www.ofgem.gov.uk/ofgem-publications/48155/2riiogd1fpoutputsincentivesdec12.pdf.