Compendium

Board Staff Cross-Examination Materials

Witness Panel 1 and Panel 1A

Enbridge 2014-2018 Customized IR Application

EB-2012-0459

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Lawrence Kaufmann

Resume

February 2014

Address:	Office: 22 E. Mifflin St., Suite 302 Madison, WI 53703 (608) 257-1522	Home: 3730 Hammersley Ave. Madison, WI 53705 (608) 443-9813 (cell)

Education:	Ph.D.:	Economics, University of Wisconsin-Madison, 1993
	BA & MA:	Economics, University of Missouri-Columbia, 1984
	High School:	St. Louis University High, St. Louis, MO, 1980

Relevant Work Experience, Primary Positions:

December 2008 – present: President, Kaufmann Consulting and Senior Advisor, Pacific Economics Group and Navigant Consulting

Advise companies and public agencies, particularly energy utilities and regulators, on various regulatory and industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

January 2001 – December 2008: Partner, Pacific Economics Group, Madison, WI
November 1998 – December 2000: Vice President, Pacific Economics Group, Madison, WI

Advise energy utilities and regulators on various industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

August 1993 – October 1998: Senior Economist, Christensen Associates, Madison, WI

Assisted in the development and evaluation of PBR plans for energy utilities and other regulated enterprises. Duties included theoretical and empirical research (including the estimation of total factor productivity trends), written reports, client contact and briefings, public presentations, and monitoring regulatory trends in the United States and overseas.

January 1993 - July 1993: Research Assistant to Dr. Robert Baldwin, Department of Economics, University of Wisconsin-Madison

Project investigated whether dumping penalties imposed by the United States have led to a diversion of imports from the nations on which the duties were assessed to other exporters.

January 1991 - May 1993: Dissertation research on the impact of foreign investment on Mexican firms.

Dissertation examined whether there has been any spillover of advanced multinational technologies to competing Mexican firms. Research included development of a theoretical model of spillovers through Mexican recruitment of multinational personnel, interviews and data collection in Mexico, and empirical tests of theoretical conclusions. Dissertation research was funded through a fellowship from the Mellon Foundation.

June 1989 - December 1990: Research Associate, Credit Union National Association, Madison, WI

Initiated and assisted on several long-term research projects, including the assessment of capital positions at Corporate credit unions, comparing the asset portfolios of credit unions and banks, and analysis concerning the development of credit union industries in Poland and Costa Rica.

January 1988 - August 1988: Investment Banking Officer and Associate Economist, Centerre Bank, St. Louis, MO
April 1985 - December 1987: Assistant Economist, Centerre Bank, St. Louis, MO

As Assistant Economist, the primary duty was to prepare country risk reports on nations to which the bank was lending. As Associate Economist and Investment Banking Officer, duties expanded to include writing a twice-weekly column on interest rate trends and preparing special reports on regional, national and international economic trends for senior management.

August 1983 - December 1984 and four semesters during the period September 1988 - May 1993:

Teaching assistant for classes in introductory microeconomics, introductory macroeconomics, international economics and the history of economic thought.

Professional Memberships: American Economic Association
National Association of Business Economists

Foreign Language Proficiency: Spanish

Major Consulting Projects:

1. Survey and analysis of implementation issues associated with customer-specific reliability metrics. Ontario Energy Board, 2013-14.
2. Empirical analysis and recommendation of appropriate reliability benchmarks. Ontario Energy Board, 2013-14
3. Cost of service review (transmission and distribution operations) Israel Electric Corporation. Public Utility Authority of Israel, 2013-14.
4. Value of reliability improvements from undergrounding power lines. Wisconsin Public Service, 2013.
5. Advise on and assess gas distribution incentive regulation plans. Ontario Energy Board, 2013-14.

6. Advise on price control application. UK Power Networks, 2013.
7. Advise on electricity distribution incentive regulation plans and other aspects of renewed regulatory framework for electricity. Ontario Energy Board, 2012-13.
8. Response to Productivity Commission Report on Energy Network Regulatory Frameworks. Energy Safe Victoria, 2012.
9. Statement on appropriate opt-out policies for smart meters to Wisconsin Public Service Commission. SMART Water, 2012.
10. Submission to Australia's Productivity Commission on the role of benchmarking in utility regulation. Energy Safe Victoria, 2012.
11. Assist Staff on review of cost of service applications for Enbridge Gas Distribution and Union Gas. Ontario Energy Board, 2012.
12. Assist with responses on data requests in testimony on alternative regulation plan. Potomac Electric Power, 2011-12.
13. Assess incentive regulation plans for Union Gas and Enbridge Gas Distribution in Ontario. Ontario Energy Board, 2011.
14. Advise on demand-side management and decoupling plans, and utility involvement in conservation and renewable energy businesses. ATCO Gas, 2011.
15. Advise on defining and measuring utility performance and the use of performance measures and standards in electric utility regulation. Ontario Energy Board, 2011-12.
16. Advise on rate mitigation strategies. Ontario Energy Board, 2011.
17. Advise on PBR strategy in Alberta. EDTI, 2011-12.
18. Estimate total factor productivity trend for gas distributors in New Zealand. Powerco, on behalf of industry, 2011.
19. Evaluation of reliability standards and alternative regulatory approaches for maintaining the reliability of electricity supplies. Ontario Energy Board, 2010-12
20. Prepare submission on rule change application and respond to consultant reports on TFP spreadsheet simulations and the impact of the regulatory framework on energy safety. Energy Safe Victoria, 2010.
21. Research on operating productivity and input price changes and testimony in support of an incentive-based formula to recover changes in gas distribution operating expenses. National Grid, 2010.
22. Prepare submission on rule change application and respond to consultant reports on TFP methodology. Essential Services Commission, 2010.
23. Advise on submission on rule change application. Victoria Department of Primary Industries, 2010.
24. Productivity research Victoria gas distribution industry, Essential Services Commission, 2010.
25. Productivity research Victorian power distribution industry, Essential Services Commission, 2010.

26. Advise on revenue decoupling and alternative regulatory strategies in context of upcoming gas distribution rate case. Northwest Natural Gas, 2009-2010.
27. Advise on revenue decoupling. Ontario Energy Board, 2009-2010.
28. Develop a "top down," econometrically-based measure of reductions in gas consumption resulting from utility DSM programs, and evaluate the merits of this approach compared to the existing "bottom up" methodology. Ontario Energy Board, 2009-2010.
29. Respond to proposals to amend National Energy Regulatory Framework to allow alternative approaches to incentive regulation. Essential Services Commission, 2009-2010.
30. Evaluate consultant reports and prepare submission on the update of price control formulas. New Zealand Energy Network Association, 2009.
31. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.
32. Estimate TFP trend for New Zealand electricity distributors. New Zealand Energy Network Association 2009.
33. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.
34. Submission on the application of total factor productivity in utility network regulation. Essential Services Commission, 2008-09.
35. Estimate total factor productivity trends, benchmark gas distribution cost performance, and testify in support of research. Bay State Gas, 2008-09.
36. Advise on appropriate regulatory treatment of early termination fees in retail energy markets. Essential Services Commission, 2008.
37. Advise on appropriate regulation of gas connection charges. Essential Services Commission, 2008.
38. Advise on appropriate cost of capital. Jamaica Public Service, 2008.
39. Estimate total factor productivity trends and benchmark bundled power cost performance for use in a productivity based regulation plan. Jamaica Public Service, 2008.
40. Estimate gas distribution total factor productivity trends. Essential Services Commission, 2008.
41. Update estimate total factor productivity trends electricity distributors. Essential Services Commission, 2008.
42. Respond to productivity and benchmarking studies. New Zealand Electricity Networks Association, 2008.
43. Response to comments on appropriate productivity and input price measures to be used to update gas distributors' operating expenses. Essential Services Commission, 2007-08.
44. Advise on update of performance based regulatory plan for power distributors, including recommendations for total-factor productivity based X factors. Ontario Energy Board, 2007-08.
45. Estimate lost wage and health damages. Wolfgram and Associates, 2007.

46. Response to critique of X factor recommendations. Ontario Energy Board, 2007.
47. Review of benchmarking methods and proposed benchmarking for the pricing of unbundled copper local loop. Telecom NZ, 2007.
48. Report on the relationship between revenue decoupling and performance-based regulatory mechanisms. Massachusetts energy distribution companies, 2007.
49. Research on revenue decoupling experience in California. National Grid, 2007.
50. Report on regulatory reforms needed to facilitate demand response, advanced metering infrastructure and energy efficiency objectives. Essential Services Commission, 2007.
51. Estimate lost wage and health damages. Wolfrgram and Associates, 2007.
52. Evaluation of gas distribution construction cost trends. Essential Services Commission, 2007.
53. Appropriate productivity trends and labor inflation rates to be used to adjust operating expenses in incentive-based ratemaking. Essential Services Commission, 2007.
54. Testify in support of rate adjustment under a performance based regulation plan. Bay State Gas, 2007.
55. Report on service quality regulation and benchmarking, submitted as expert witness testimony. Detroit Edison, 2007.
56. Develop and testify in support of alternative regulation plan for gas distribution services. Client confidential at this time, 2007.
57. Evolution of energy asset management companies and outsourcing relationships. Davidson Kempner Advisers, 2007.
58. O&M partial factor productivity trends for gas distribution services. Essential Services Commission, 2006-07.
59. Principles for designing gas supply PBR plans and assessing the impact of retail gas costs. DLA Piper Rudnick, 2006-07.
60. Framework for analyzing appropriate early termination fees in competitive retail electricity markets. Essential Services Commission, 2006-07.
61. Testify in support of exogenous factor recovery of revenues lost due to declining natural gas usage. Bay State Gas, 2006.
62. Service quality benchmarking. Canadian Electricity Association, 2006.
63. Analyze natural resource and recreational damage calculations for environmental damage to trout stream. Michael, Best and Friedrich, 2006.
64. Evaluate outsourcing contract and report benchmarking Envestra's gas distribution operations and maintenance expenses. ESCOSA, 2006.
65. Report on the use of partial factor productivity trends in the updated gas access arrangement. Essential Services Commission, 2006.
66. Advise on approved X factors and total factor productivity trends in approved alternative regulation plans for electric utilities. Central Maine Power, 2006.

67. Estimate total factor productivity and input price trends power distribution industries in all Australian States and territories, Essential Services Commission, 2006.

68. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

69. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

70. Testimony on treatment of outsourcing contract costs and labor-nonlabor cost allocations. Essential Services Commission, 2005-06.

71. Incorporate lessons from incentive regulation and benchmarking overseas into newly-established regulatory framework for nation's electric utilities. Bundesnetzagentur (BNA), Bonn Germany, 2005-2006.

72. Submission to Ministerial Council on Energy related to Regulatory Rulemaking. Essential Services Commission, 2005.

73. Evaluation of early termination fee policies for energy retailers. Essential Services Commission, 2005.

74. Advise on alternative regulation strategies for gas distribution services. Client wishes to remain confidential at this time, 2005-2006.

75. Report on comprehensive framework for using performance indicators to evaluate market power abuses, efficiency gains, and the distribution of benefits to stakeholders. Essential Services Commission, 2005.

76. Evaluation of regulatory options and estimation of total factor productivity for Port of Melbourne Corporation. Essential Services Commission, 2005.

77. Evaluation of regulatory options for taxi services in Melbourne, Australia. Essential Services Commission, 2005.

78. White Paper advising government agency on regulatory reform of State's electric power industry. Department of Natural Resources Newfoundland and Labrador, 2005.

79. Review report on CAPM and differences in beta between rural and urban power distributors. Essential Services Commission, 2005.

80. Develop "incentive power" model and apply towards evaluation of regulatory options in Victoria, Australia. Essential Services Commission, 2004-2005.

81. Review report on labor price forecasts for Victoria, Australia. Essential Services Commission, 2004-2005.

82. Develop and testify in support of performance-based regulation plan. Bay State Gas, 2004-2005.

83. Review of gas regulatory framework in Ontario, Canada. Ontario Energy Board, 2004-2005.

84. Benchmarking gas distribution operations. Powerco, Vector, NGC (New Zealand), 2004.

85. Report on methodologies for updating CPI-X price controls and assemble US gas transmission pipeline data, to be used in update of price controls for gas transmission services. Comision Reguladora de Energia (Mexico), 2004-2005.

86. Benchmark comprehensive power and water utility operations. Aqualectra (Curacao, Netherlands Antilles), 2004-2005.
87. Benchmarking power distribution operations. Energex and Ergon Energy, 2004.
88. Regulatory treatment of hub and storage facilities. NICOR Gas, 2004.
89. Review and comment on proposed service quality regulation. Essential Services Commission, 2004.
90. Review and contribute to report on ring fencing policies. Essential Services Commission, Victoria Australia, 2004.
91. Estimate lost earnings in litigation case. Wolfgram and Gherardini, 2004.
92. Respond to Productivity Commission report on Gas Access Arrangements. Essential Services Commission, Victoria Australia, 2004.
93. Analysis of PBR plans for rates and service quality worldwide. Jamaica Public Service, 2004.
94. Undertake benchmarking and total factor productivity studies in support of an X factor in a performance-based regulatory plan. Jamaica Public Service, 2003-2004.
95. Evaluate incentive regulation options. Questar Gas, 2003-2004.
96. Project evaluating implementation of total factor productivity in energy utility regulation. Essential Services Commission, Victoria Australia, 2003-2005.
97. Evaluate incentive regulation reports commissioned by Australian Competition and Consumer Commission. Essential Services Commission, Victoria Australia, 2003.
98. Evaluate proposed regulatory thresholds regime. Powerco New Zealand, 2003.
99. Evaluate benchmarking methods and regulatory reform proposals. Jamaica Public Service, 2003.
100. Evaluate proposals for service quality regulation in province of Ontario. Hydro One, 2003.
101. Evaluate benchmarking methods and regulatory reform proposals. Overseas New Zealand client wishes to remain confidential at this time, 2003.
102. US-Japan power transmission benchmarking. Central Research Institute of Electric Power Industry (Japan), 2003.
103. Benchmarking power distribution operations and maintenance (O&M) costs benchmarking and O&M productivity growth. Superintendente de Electricidad (Bolivia), 2003.
104. Benchmarking gas distribution operations and maintenance expenses. ACTEW (Australia), 2003.
105. Estimate lost earnings in wrongful death case. Wolfgram and Gherardini, 2003.
106. Advise on updating incentive plan for demand-side management. Hawaiian Electric, 2003.
107. Estimate and testify in support of damages in patent infringement case, Trombetta, LLC vs. Dana Corporation and AEC. Ryan, Kromholz and Mannion, 2003.
108. Analyze service quality proposals for a natural gas distributor, recommend modifications and testify in support of recommendations. New England Gas, 2002-2003.

109. Develop a service quality incentive plan for power distributors in Queensland, Australia; the plan is to be developed through a consultative process between the companies, major customer groups, and the regulator. Queensland Competition Authority, 2002-2003.

110. Consultation on developments regarding Wisconsin Electric's "Power the Future" initiative. Fidelity Investments, 2002.

111. Confidential report on US experience with benchmarking and alternative regulation. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

112. Confidential report on capital cost measurement. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

113. Report on merits and feasibility of benchmarking New Zealand power distributors. United Networks, 2002.

114. Impact of gas marketing expenditures on residential gas consumption. Envestra, 2002.

115. Advise on index-based performance-based regulation plan for a power distribution utility. Client wishes to remain confidential at this time, 2002.

116. Estimate productivity trend gas distribution industry and testify in support of trend. Boston Gas, 2002-2003.

117. Gas distribution benchmarking study. TXU Australia, Envestra and Multinet, 2002.

118. Benchmarking power transmission cost. Transend, 2002.

119. Advise on the development of an incentive regulation proposal for a North American power transmission utility. Hydro One Networks, 2001-2002.

120. Application of productivity and econometric benchmarking in an update of an incentive regulation plan. Ameren UE, 2001-2002.

121. Litigation regarding violations of Unfair Trade Practices Act for Tamoxifen, Taxol, and Buspar prescription drugs. Miner, Barnhill, and Galland, P.C., 2001-2002.

122. Recommend reforms of Western Australia power market, including reforms of wholesale markets, retail markets, structure of the incumbent utility, and regulatory arrangements; work was summarized in a report to the Electricity Reform Task Force. Western Power, 2001.

123. Faculty member of Regulatory Training Seminar in Bolivia. Seminar organized by the Public Utility Research Center and sponsored by SIRESE, 2001.

124. White Paper on implementing total factor productivity measures in regulation for the Utility Distributor's Forum. CitiPower, 2001.

125. Electronic forum on service quality incentives and research topics. Edison Electric Institute, 2001.

126. Economies of scale and scope in power services. Western Power, 2001.

127. Report evaluating the merits of alternative benchmarking methods and their application to energy distributors. Electricity Supply Association of Australia, 2001.

128. Response to report on benchmarking and incentive regulation. Client confidential at this time, 2000-2001.

129. Report on consistency of Price Determination with legislative mandates. TXU Australia, 2000-2001.

130. Develop methodology for service quality benchmarking and construction of appropriate deadbands. Massachusetts Gas and Electric Distribution Companies, 2000.

131. Advise on Performance-Based Regulation strategy, including development of a service quality incentive. BCGas, 2000.

132. Power distribution benchmarking. Queensland Competition Authority, 2000.

133. Develop and testify in support of service quality incentive. Western Resources, 2000.

134. Response to regulatory proposals for "ring fencing" operations. CitiPower, 2000.

135. Benchmarking evaluation of power distribution costs. Client name withheld, 2000.

136. Updated White Paper on Metering and Billing Competition in California. Edison Electric Institute, 2000.

137. Economies of scale and scope in power delivery and metering services. Massachusetts Utility Distribution Companies, 2000.

138. Evaluation of merger benefits. Client wishes to remain anonymous at this time, 2000.

139. Response to study on benchmarking capital spending. CitiPower, 2000.

140. Response to incentive regulation proposals of Pareto Economics in Victorian distribution price review. CitiPower, 2000.

141. Estimate scale economies in power generation, scope economies between power transmission and power generation, and implications for public policy in Western Australia. Western Power, 2000.

142. White Paper on "best practice" regulation and evaluation of price and non-price regulation of energy and water utilities in Australia, the US, and the UK. Electricity Association of New South Wales, 2000.

143. Power transmission benchmarking. Client confidential at this time, 2000.

144. Development of performance-based regulation plan for power distribution services. Texas Utilities, 2000.

145. Response to UMS benchmarking study on O&M costs. Victorian power distributors, 2000.

146. Response to Consultation Paper on Detailed Proposal for Form of the Price Control. CitiPower, 1999-2000.

147. White Paper on cost structure of power distribution. Australian power distributors (coalition contact: the Electricity Supply Association of Australia), 1999-2000.

148. White Paper on benchmarking principles and applications. Victorian power distributors, 1999-2000.

149. Service quality testimony. Hawaiian Electric, Maui Electric, and Hawaii Electric Light, 1999.

150. Faculty member of Regulatory Training Seminar in Argentina. Seminar organized by the Public Utility Research Center and sponsored by Enargas, 1999.

151. Service quality benchmarking study. Southern California Edison, 1999.

152. US-Australia performance benchmarking study. Victorian Distribution Businesses, Victoria, Australia, 1999.

153. Cost benchmarking for power delivery and customer services. Southern California Edison, 1999.

154. Development of Service Quality Incentive and Testimony in Support of Plan. Oklahoma Gas and Electric, 1999.

155. Evaluation of Intervenor Assessments of Customer Benefits in Proposed Merger. Western Resources, 1999.

156. Response to Regulator Proposals for Regulatory Methodology, Efficiency Measurement and Benefit-Sharing, and Form of Distribution Price Controls. CitiPower, Australia, 1999.

157. Response to Incentive Regulation Proposal of Australian Competition and Consumer Commission. CitiPower, Australia, 1998.

158. Report on Metering and Billing Competition in California. Edison Electric Institute, 1998-99.

159. Evaluation of Economies of Vertical Integration for Electric Utilities in Illinois. Edison Electric Institute, 1998.

160. Assessment of Cost Performance of Power Distributors in the United States and Australian state of Victoria. Victorian Power Distributors, 1998.

161. Formal Response to Regulatory Proposals for Price Cap Regulation/Development of Regulatory Options. Victorian Power Distributors, 1998.

162. Development of Service Quality Incentive and Testimony in Support of Plan. Louisville Gas and Electric/Kentucky Utilities, 1998.

163. Regulatory Support for Overall PBR Strategy. Louisville Gas and Electric/Kentucky Utilities, 1998.

164. Testimony on Impact of Brand Name Restrictions in Maine’s Retail Energy Markets. Edison Electric Institute, 1998.

165. Development of Service Quality Incentive. Hawaiian Electric, 1998.

166. Regulatory Support for Comprehensive PBR Strategy and Feasibility of Retail Competition in Power Supply Services. Hawaiian Electric, 1997-98.

167. White Paper on Controlling Cross-Subsidization in Electric Utility Regulation. Edison Electric Institute, 1997-98.

168. White Paper on Cost Structure of Integrated Electric Utilities and Implications for Retail Competition. Edison Electric Institute, 1997-98.

169. Regulatory Support for a Price Cap Plan for Combination Utility. San Diego Gas and Electric, 1997-98.

170. White Paper on Price Cap Methodologies for Power Distributors in Victoria, Australia. Victorian Power Distributors, 1997.

171. Development of a Price Cap Plan for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.
172. White Paper on Price Cap Regulation for Power Distribution. Edison Electric Institute, 1997.
173. Comprehensive Report on Performance-Based Regulatory Options for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.
174. White Paper on Use of Electric Utility Brand Names in Competitive Markets. Edison Electric Institute, 1997.
175. Options for Price Cap Regulation for Power Distribution in Colombia. Comision Reguladora de Energía y Gas en Colombia, 1997.
176. Options for Performance-Based Regulation for Power Transmission and Stranded Cost Recovery for an Electric Utility. Client wishes to remain confidential at this time, 1997.
177. Regulatory Support for an Index-Based Incentive Plan of a Local Gas Distribution Utility. BCGas, 1997.
178. Recommendations for a service quality incentive plan. Hawaiian Electric, 1997.
179. Survey of Service Quality Incentive Plans and Assessment of Options. BCGas, 1996.
180. Regulatory Support for a Price Cap Plan. Southern California Gas, 1996.
181. Determination of service territories for newly-privatized gas distributors in Mexico. Comisión Reguladora de Energía, 1996.
182. Assessment of Regulatory Options for a Public Enterprise. United States Postal Service, 1996-97.
183. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Brooklyn Union Gas, 1996.
184. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Client wishes to remain confidential at this time, 1996.
185. Assessment of Options for Service Quality Incentives. Client wishes to remain confidential at this time, 1996.
186. Development of a Price Cap Plan for an Electric Utility. Client wishes to remain confidential at this time, 1996.
187. Assessment of Lessons from Natural Gas Restructuring for Electric Utilities. Client wishes to remain confidential at this time, 1996.
188. Advised on the Establishment of a Regulatory Framework for the Mexican Natural Gas Industry. Comision Reguladora de Energia, 1996.
189. White Paper on Unbundling Electric Utility Services. Edison Electric Institute, 1996.
190. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Boston Gas, 1995.
191. Development of a Price Cap Plan for a Local Gas Distribution Utility. Client wishes to remain confidential at this time, 1995.

192. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Client outside of the United States wishes to remain confidential at this time, 1995.

193. Organization of a Conference on Price Cap Regulation. Edison Electric Institute, 1995.

194. Development of Regulatory Strategies Regarding the Transition to Retail Competition in the Electric Power Industry. Niagara Mohawk Power, 1995.

195. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Alberta Power Limited, 1995.

196. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Public Service Electric and Gas, 1995.

197. Development of a Price Cap Plan for the Electric Operations of a Combination Utility. Public Service Electric and Gas, 1995.

198. White Paper on Incentive Regulation Theory and Its Application to Electric Utilities. Electric Power Research Institute, 1994-95.

199. Productivity Trends of U.S. Gas Distributors. Southern California Gas, 1994-95.

200. White Paper on Price Cap Regulation. Edison Electric Institute, 1994.

201. Regulatory Support for a Price Cap Plan. Central Maine Power, 1994.

202. Advanced Benchmarking Methods for U.S. Electric Utilities. Southern Electrical System, 1994.

203. Development of and Regulatory Support for a Price Cap Plan. Niagara Mohawk Power, 1994.

204. Competitive Price Scenarios for Power Markets in the Northeastern U.S. Niagara Mohawk Power, 1993-94.

205. Survey of Price Cap Plans in the U.S. and Abroad. Niagara Mohawk Power, 1993.

Expert Witness Testimony:

1. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: sur-surrebuttal testimony on the value of reliability improvements from undergrounding power lines.

2. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: rebuttal testimony on the value of reliability improvements from undergrounding power lines.

3. Before the Wisconsin Public Service Commission; evidence on behalf of SMART Water, 2012. Statement on appropriate opt-out policies for smart meters.

4. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: rebuttal testimony in support of a net inflation adjustment mechanism applied to operating and maintenance expenditures.

5. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: empirical support for a net inflation adjustment mechanism applied to operating and maintenance expenditures.

6. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2009. Subject: direct testimony on performance based regulation.

7. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2008. Subject: estimating partial factor productivity growth for O&M expenditures for natural gas distributors.

8. Before the Ontario Energy Board, 2008. Subject: appropriate values for total factor productivity-based productivity factor; benchmarking-based productivity "stretch factors;" and appropriate thresholds for capital investment modules; in an incentive regulation plan for electricity distributors in the Province.

9. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: direct testimony on performance based regulation.

10. Before the Circuit Court of the City of St. Louis, Missouri, Division 9, in Michele Thrash v. Freightliner *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and medical treatment.

11. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: panel testimony on revenue decoupling and performance based regulation.

12. Before the New Zealand Commerce Commission, evidence on behalf of Telecom New Zealand, 2007. Subject: principles for price benchmarking and the merits of alternative methods of benchmarking unbundled copper local loop prices.

13. Before the Circuit Court of the City of St. Louis, Missouri, Division 13, in Anastacia McNutt v. Globe Transport, Inc *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and past and future medical treatment.

14. Before the Michigan Public Service Commission; evidence on behalf of Detroit Edison, 2007. Subject: service quality regulation and benchmarking.

15. Before the Appeal Panel, South Australia, Australia; evidence on behalf of the Essential Services Commission of South Australia, 2006. Subject: the operating expenditures and outsourcing management fee of Envestra Ltd.

16. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: rebuttal testimony on exogenous recovery of revenues lost due to declining natural gas usage.

17. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: direct testimony on exogenous recovery of revenues lost due to declining natural gas usage.

18. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2006. Subject: regulatory treatment of an outsourcing contract to a related corporate party in a power distribution price determination.

19. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2005. Subject: labor and non-labor shares in operating expenditures.

20. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: rebuttal testimony on performance based regulation and benchmarking.

21. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: performance based regulation and benchmarking.

22. Before the New Zealand Commerce Commission, evidence on behalf of Vector and NGC, 2004. Benchmarking evidence for New Zealand gas distributors.

23. Before the New Zealand Commerce Commission, evidence on behalf of Powerco, 2003. Evaluation of total factor productivity and benchmarking evidence in studies undertaken for the Commission.

24. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: rebuttal testimony on performance based regulation, total factor productivity measurement and benchmarking

25. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: performance based regulation, total factor productivity measurement and benchmarking

26. Before the US District Court for the Western District of Wisconsin, Trombetta, LLC vs. Dana Corporation and AEC, 2003. Subject: estimate damages in solenoid patent infringement case.

27. Before the Rhode Island Public Utilities Commission: evidence on behalf of New England Gas, 2003. Subject: direct testimony on alternative service quality regulation proposals.

28. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2001. Subject: reply to surrebuttal testimony in support of service quality incentive plan.

29. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: rebuttal testimony in support of service quality incentive plan.

30. Before the Supreme Court of Victoria, Australia; evidence on behalf of TXU Australia, 2000. Subject: Whether the regulator’s price determination complied with legal mandates to use price-based incentive regulation.

31. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

32. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Massachusetts gas and electric distribution companies, 2000. Subject: Service quality benchmarking.

33. Before the Hawaii Public Service Commission; evidence on behalf of Hawaiian Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

34. Before the Oklahoma Corporation Commission; evidence on behalf of Oklahoma Gas and Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.
35. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Rebuttal testimony in support of service quality incentive plan and benefits of companies' regulatory proposal to low-income customers.
36. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.
37. Before the Maine Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1998. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.
38. Before the California Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1997. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

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1. *The Price Cap Designers Handbook* (with M. N. Lowry), Edison Electric Institute, 1995.
2. "The Treatment of Z Factors in Price Cap Plans" (with Mark Newton Lowry), *Applied Economics Letters*, 2: 1995.
3. "Forecasting Productivity Trends of Natural Gas Distributors" (with Mark Newton Lowry), *AGA Forecasting Review*, March 1996.
4. *Performance-Based Regulation for Electric Utilities: The State of the Art and Directions for Further Research* (with Mark Newton Lowry), Palo Alto: Electric Power Research Institute, 1996.
5. *Developing Unbundled Electric Power Service Offerings: Case Studies of Methods and Issues* (with Laurence Kirsch), Washington: Edison Electric Institute, 1996.
6. "A Theoretical Model of Spillovers Through Labor Recruitment", *International Economic Journal*, Autumn 1997.
7. *Branding Electric Utility Products: Analysis and Experience in Related Industries* (with Mark Newton Lowry and David Hovde), Washington: Edison Electric Institute, 1997.
8. "The Branding Benefit", *Electric Perspectives*, November 1997.
9. *Price Cap Regulation for Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1998.
10. *Controlling for Cross-Subsidization in Electric Utility Regulation* (with Mark Meitzen and Mark Netwon Lowry), Washington: Edison Electric Institute, 1998.
11. "Price Caps for Distribution Service: Do They Make Sense?", *Edison Times*, December 1998 (with Eric Ackerman and Mark Newton Lowry).

12. *Economies of Scale and Scope in Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1999.

13. *Competition for Metering, Billing and Information Services: The Experience in California So Far*, Edison Electric Institute, 1999.

14. *Third Party Metering, Billing and Information Services: Further Evidence from California*, Edison Electric Institute, 2000.

15. "Performance Based Regulation of Energy Utilities" (with Mark Newton Lowry), *Energy Law Journal*, 2002

16. "Performance Based Regulation and Business Strategy" (with Mark Newton Lowry), *Natural Gas*, 2003.

17. "Performance Based Regulation and Energy Utility Business Strategy" (with Mark Newton Lowry), *Natural Gas and Electric Power Industries Analysis 2003*, Financial Communications, Houston, 2003

18. "Price Control Regulation in North America: Role of Indexing and Benchmarking," (with M.N. Lowry and L. Getachew), *Proceedings of Market Design Conference*, Stockholm, Sweden, 2003.

19. "Performance Based Regulation Developments for Natural Gas Utilities" (with Mark Newton Lowry), *Natural Gas and Electricity*, 2004.

20. "Incentive Power and the Design of Regulatory Regimes," *Network*, December 2005.

21. "Alternative Regulation for Electric Utilities" (with Mark Newton Lowry), *Electricity Journal*, June 2006.

22. "Performance Indicators and Price Monitoring: Assessing Market Power," *Network*, March 2007.

23. "Incentive Regulation in North American Energy Markets" *Energy Law and Policy*, Carswell Publishing, Toronto, Canada, 2009.

24. "Regulatory Reform in Ontario: Successes, Shortcomings and Unfinished Business" *Public Utilities Fortnightly*, November 2009

Presentations at Seminars and Professional Meetings:

1. Department of Energy/NARUC, Orlando, FL, 1995.
2. Illinois Commerce Commission and the Center for Regulatory Studies, St. Charles, IL, 1995.
3. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 1995.
4. Marketing Conference, Edison Electric Institute, Chicago, IL, 1997.
5. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 1997.
6. Code of Conduct Conference, Denver, CO, 1997.
7. Code of Conduct Conference, Denver, CO, 1998.
8. Forum on Price Cap Regulation for Power Distribution. Melbourne, Australia, 1998.
9. Conference on Competition and Regulatory Reform in Hawaii. Honolulu, HI, 1998
10. Alternative Approaches Towards Price Cap Regulation. Melbourne, Australia, 1998.
11. Economics Meetings, Edison Electric Institute. Charlotte, NC, 1998.
12. Metering, Billing and Information Services Policy Convention, EEI, Chicago, IL, 1999.

13. Electricity Deregulation Conference. Vail, CO, 1999.
14. PURC Regulatory Training Seminar for Natural Gas Policy, Buenos Aires, Argentina, 1999.
15. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2000.
16. Seminar on Theory and Practice of Economic Regulation, Sydney, Australia, 2000.
17. Power Delivery Reliability Conference. Denver, CO, 2000.
18. Performance-Based Regulation Conference. Chicago, IL, 2000.
19. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 2000.
20. Performance-Based Ratemaking Conference, Denver, CO 2000.
21. Energy Forum, Institute of Public Affairs, Melbourne, Australia, 2000.
22. Chamber of Commerce and Industry, Perth, Australia, 2001.
23. Energy Regulation Conference, Melbourne, Australia, 2001.
24. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2001.
25. PURC Regulatory Training Seminar, La Paz, Bolivia, 2001.
26. Performance-Based Regulation Conference, Denver, CO, 2001.
27. Cost Structure of Energy Networks, Sydney, Australia, 2002.
28. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2002.
29. Performance-Based Ratemaking Conference, Denver, CO 2002.
30. How to Regulate Electricity Lines Companies?, New Zealand Institute for the Study of Competition and Regulation, Wellington, New Zealand, 2003
31. Public Utility Regulation Seminar: Tariff Design and Incentives, Acapulco, Mexico, 2003
32. Rates and Regulation Meeting: Southeastern Electric Exchange, Williamsburg, VA, 2003.
33. Workshop on Service Quality Regulation in Ontario, Toronto, ON 2003.
34. Joint Canadian Electricity Association Distribution Council and Customer Council Meeting, Halifax, Nova Scotia, 2004.
35. Asia-Pacific Productivity Conference, Brisbane, Australia, 2004. [invitation, paper submitted]
36. Workshop on Productivity Measurement, Melbourne Australia, 2005.
37. Utility Regulators Forum, Canberra Australia, 2005.
38. CAMPUT Energy Regulation Course, Kingston Canada, 2006.
39. Performance Based Regulation Seminar, Toronto Canada, 2006.
40. Performance Benchmarking for Energy Utilities, Arlington, Virginia, 2006.
41. Performance Benchmarking for Energy Utilities, Seattle, Washington, 2007.
42. Alternative Regulation Seminar, Boston, Massachusetts, 2007.
43. CAMPUT Energy Regulation Course, Kingston Canada, 2007.
44. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
45. Performance Benchmarking for Energy Utilities, Denver, Colorado, 2008.
46. Alternative Regulation Seminar, Toronto, Canada, 2008.
47. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
48. CAMPUT Energy Regulation Course, Kingston Canada, 2008.
49. Performance Benchmarking for Energy Utilities, Chicago, IL, 2008.
50. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2009.
51. Alternative Regulation Seminar, Boston, MA, 2009.
52. CAMPUT Energy Regulation Course, Kingston Canada, 2009.
53. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
54. Alternative Regulation Seminar, Boston, MA, 2010.
55. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
56. CAMPUT Energy Regulation Course, Kingston Canada, 2010.
57. Alternative Regulation Seminar, Toronto Canada 2010.

58. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2011.
59. Alternative Regulation Seminar, Philadelphia PA, 2011.
60. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2012.
61. Alternative Regulation Seminar, Chicago, IL, 2012.
62. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
63. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
64. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.

<u>BOARD STAFF RESPONSE TO UNDERTAKING OF ENBRIDGE</u>

<u>UNDERTAKING TCU1.4</u>

REF: Tr.1 p22

TO PROVIDE THE INSTRUCTIONS PROVIDED TO DR. KAUFMANN IN CONNECTION WITH THIS PROCEEDING

<u>RESPONSE</u>

The contract with Pacific Economics Research LLC lists the following scope and deliverables:

1. Review the Union and Enbridge 2012-2013 IR applications;
2. Assist Board staff in developing information requests related to the IR application, and review responses by Union and Enbridge;
3. Undertake relevant analyses to assess and evaluate the proposed IR plans filed in the Union and Enbridge IR applications such as: 1) review proposed IR plans for appropriateness (e.g. are the elements of each plan appropriate), 2) identify any concerns and information gaps, and 3) conduct other analysis as required, which may include responding to the benchmarking reports previously filed in Enbridge's recent CoS application by Concentric Energy Advisors (CEA) and Power System Engineering (PSE);
4. Review stakeholder input and provide comment as to relevancy; and
5. Testify on its research, analysis and findings before the Board.

Witness: Dr. Lawrence Kaufmann, PEG

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Ontario

BY E-MAIL

October 3, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli:

**Re: Enbridge Gas Distribution Inc. 2014-2018 Rates EB-2012-0459
Description of Pacific Economics Group Research LLC's Written Assessment**

In light of intervenor inquiries, Board staff is providing further details on the scope of Pacific Economics Group Research LLC's ("PEG") written assessment of Enbridge Gas Distribution Inc.'s ("Enbridge") proposed Customized Incentive Regulation (IR) Plan.

PEG will review the Customized IR Plan proposal put forward by Enbridge as well as the empirical and analytical support for the proposal from Concentric Energy Advisors ("CEA") and London Economics International ("LEI"). There are two main components of PEG's analysis: 1) an analysis of the regulatory design issues; and 2) an analysis of the empirical work provided in support of the plan. For both components, PEG's analysis will be guided by the principles of sound incentive regulation, the Board's objectives and policies, and the methods for undertaking rigorous empirical research necessary to calibrate incentive regulation plans.

PEG's analysis of the regulatory design issues will examine the following topics: 1) the "Customized IR"/"Building Block" form of the incentive regulation proposal; 2) LEI's analysis of the UK building experience; 3) Enbridge's proposed changes in the Z factor; 4) the interaction between the earnings sharing mechanism and the form of the IR proposal; 5) Enbridge's proposed sustainable efficiency incentive mechanism; 6) the relationship between Enbridge's proposed plan term and sustainable efficiency incentives; 7) the AU factor; and 8) variance/deferral accounts associated with Enbridge's capital projects.

Furthermore, PEG's analysis of the empirical work provided in support of Enbridge's proposal will examine: 1) the basic approach of how this research is used to assess regulatory alternatives; 2) CEA's recommended inflation factor; 3) CEA's benchmarking evidence; 4) CEA's productivity evidence; and 5) Enbridge's capital and operating expenditure forecasts in relation to productivity.

Yours truly,

Original Signed By

Pascale Duguay
Manager, Natural Gas Applications

UNDERTAKING TCU1.11

UNDERTAKING

TR Technical Conference, page 99

EGDI [Concentric] to provide the sum of capital costs plus OM&A costs for each company in the sample and for the industry as a whole (the twenty five companies) and for Enbridge, and divide by total customers for 2010 and 2011.

RESPONSE

Preliminary comments:

Using TFP-based costs[1] per customer for a single year (e.g., 2010 or 2011) to benchmark the performance of individual distributors or groups of distributors is inappropriate for the same reasons that using the growth in TFP indexes for a single year to measure the productivity of individual distributors or groups of distributors is inappropriate. To account for year-to-year volatility in the components of a TFP index, it is widely accepted that TFP results must be evaluated over a sufficiently long period, such as ten years, to identify long term trends in productivity.

In addition, it is common practice to benchmark distributors according to measures of costs per customer and costs per volume of gas delivered to customers. In fact, measures of costs per volume may be the better approach to benchmark distributors because costs per volume provides a broader view of aggregate costs in relation to total sales and transport volumes not captured on a per customer basis.

Lastly, TFP-based costs for any distributor in any year are not the same as the revenue requirement for that distributor in that year[2], mainly because TFP-based capital costs

[1] As used in this response, "TFP-based costs" are the costs that were calculated for Concentric's TFP analysis, Exhibit A2, Tab 9, Schedule 1, Pages 95 – 123.

[2] TFP-based total costs is calculated as the sum of TFP capital costs, labour, and materials. TFP-based capital costs are a calculated value; capital costs are not reported in a distributor's annual regulatory filing. TFP-based capital costs are the product of TFP-based price of capital and capital quantity. The price of capital is a calculation that includes terms for the cost of capital, depreciation, and capital gains. The capital quantity is also a calculation, based on estimates of the value in constant (real) dollars of each vintage of in-service plant. For Concentric's TFP analysis, TFP-based labour and materials costs for a year are the O&M expenses as reported in a distributor's annual regulatory filing; the sum of TFP-based labour and materials costs is distribution, transmission, and storage O&M expenses, net of pensions and benefits expense. However,

account for economic costs, such as capital gains, that are not reflected in regulatory accounting revenue requirement calculations. Annual bond yields and ROEs that serve as proxies for the cost of capital also vary from those allowed in rates for individual companies.

Total Factor Productivity is measured with an index designed to capture the trends in inputs and outputs for a given company or industry. The assumptions required to estimate total costs, especially for capital, are not designed to determine an absolute measure of cost in a given year. The overall level of TFP-based costs and year-to-year differences in TFP-based costs are significantly impacted by all of these factors. These data must therefore be considered in light of these limitations.

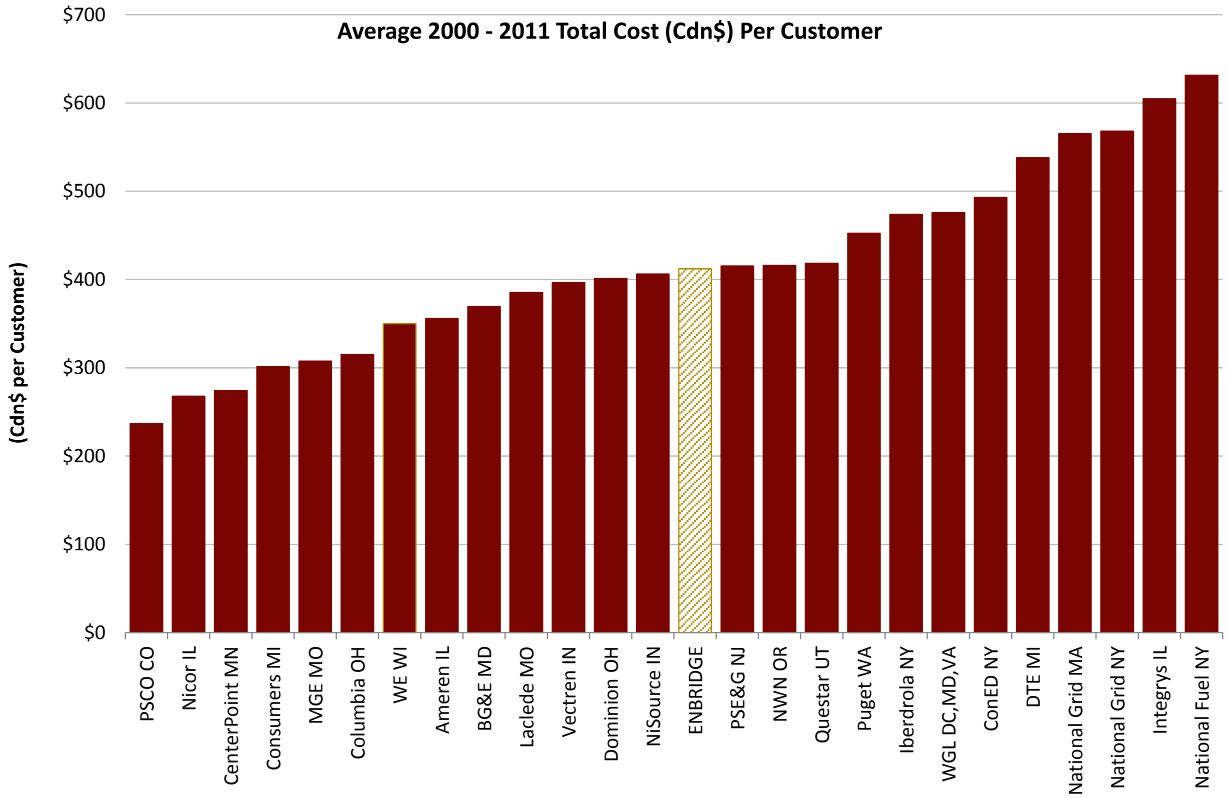
For these reasons, TFP-based costs have been provided for this response for the entire period of Concentric's TFP analysis, 2000 to 2011, and the benchmarking results are expressed as average costs per volume and costs per customer for Enbridge, the 25 Company Industry Study Group, and the seven company Sub-Group for 2000 to 2011.

Analysis and Discussion

The sum of TFP-based capital costs plus OM&A costs, divided by total customers for each of the 25 companies in the sample plus Enbridge, for the study period, 2000 to 2011 is provided in Attachment TCU1.11 page 1; cost data per volume (103m3) is provided in Attachment TCU1.11 page 2.

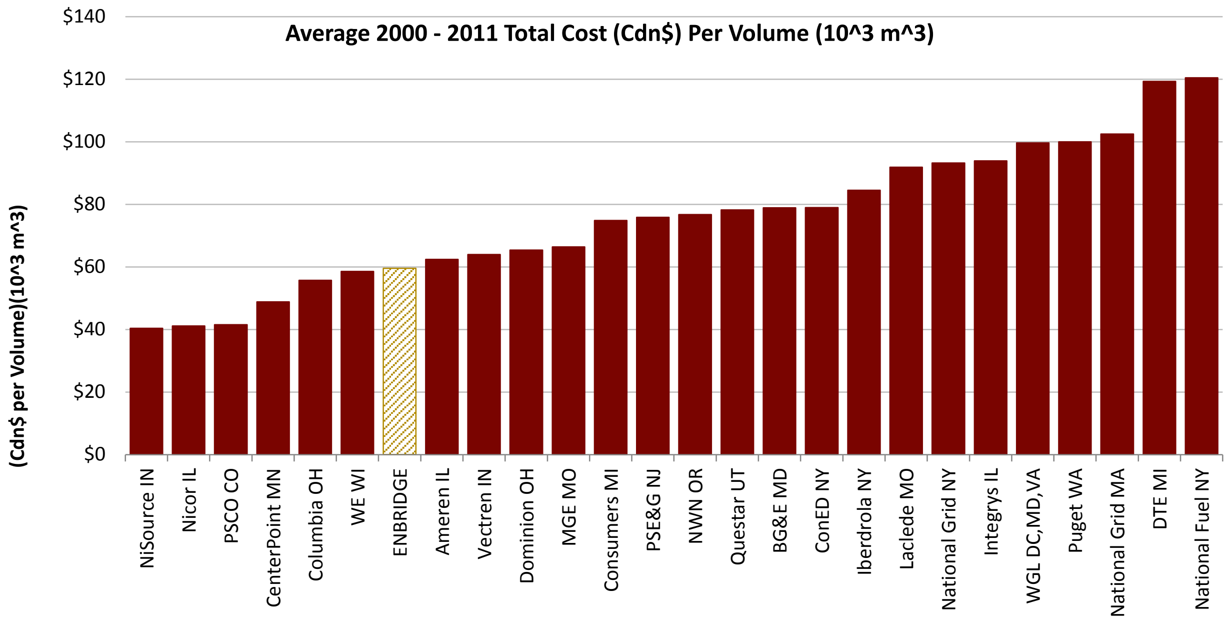
The following Figure 1, Cost per Customer benchmarking analysis, summarizes the average 2000 to 2011 cost per customer results in Attachment TCU1.11 page 1. Figure 1 indicates that Enbridge's average 2000 to 2011 average TFP-based cost is at the median for the 26 companies.

Figure 1 Benchmarking Analysis: Average Total TFP-based Cost per Customer



The following Figure 2, Cost per Volume benchmarking analysis, summarizes the average 2000 to 2011 cost per volume results in Attachment TCU1.11 page 2. Figure 2 indicates that Enbridge's average 2000 to 2011 average TFP-based cost is at the separation point between the top and second quartiles for the 26 companies.

Figure 2 Benchmarking Analysis: Average Total TFP-based Cost per Volume (10^3m^3)



The following Figure 3 provides a summary of TFP-based total costs per customer for the 25 company group, the 7 company group and Enbridge for the 2000 to 2011 study period; Figure 4 provides a summary of TFP-based total costs per volume for the 25 company group, the 7 company group and Enbridge for the 2000 to 2011 study period.

Figure 3 Total TFP-based Cost (Cdn$) Per Customer

	Total Cost (Cdn$) Per Customer		
	Industry Study Group	Seven Company Sub-Group	EGD
2000	503	483	416
2001	521	484	364
2002	521	495	463
2003	469	453	442
2004	384	366	357
2005	304	284	381
2006	283	260	412
2007	321	291	351
2008	350	315	374
2009	498	460	406
2010	459	426	463
2011	388	360	515
Average Annual Cost Per Customer			
2000-2011	417	390	412

Figure 4 Total TFP-based Cost (Cdn$) Per Volume (10^3m^3)

	Total Cost (Cdn$) Per Volume (10^3 m^3)		
	Industry Study Group	Seven Company Sub-Group	EGD
2000	78.43	75.88	52.70
2001	91.36	83.91	47.11
2002	89.38	83.88	64.39
2003	81.05	79.01	56.63
2004	71.43	69.54	48.88
2005	57.72	55.88	54.02
2006	57.42	53.33	63.99
2007	61.16	55.45	53.07
2008	66.01	60.24	57.84
2009	98.54	90.22	63.63
2010	91.04	79.43	73.08
2011	74.95	66.20	79.07
Average Annual Cost Per Volume (10^3 m^3)			
2000-2011	76.54	71.08	59.53

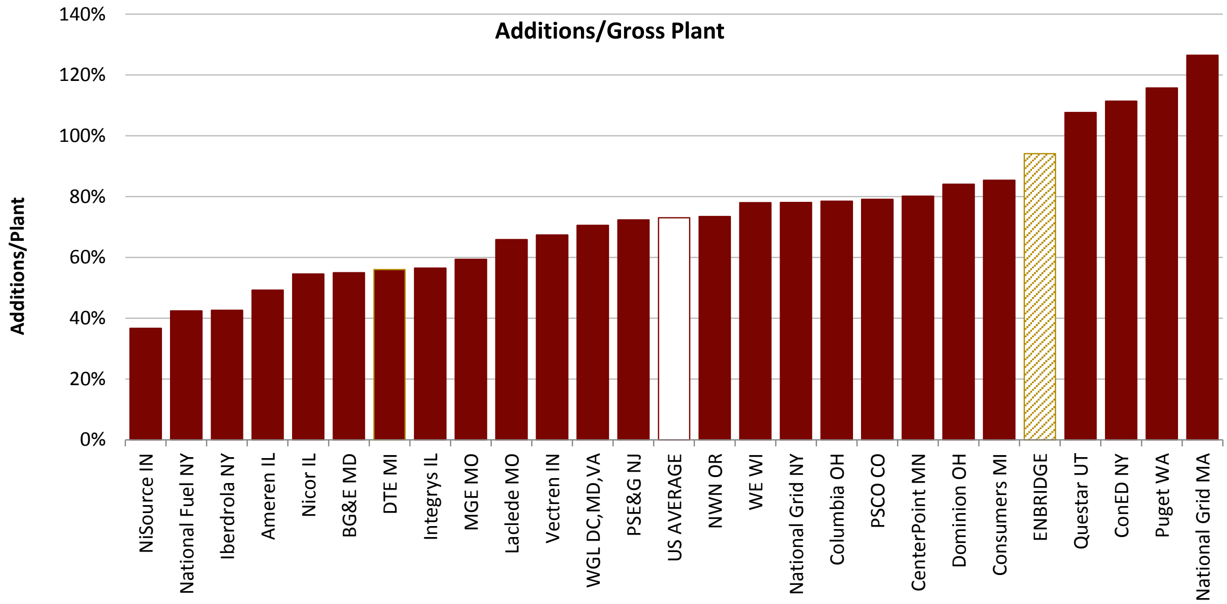
Explanation

The Concentric Incentive Ratemaking Report demonstrates that EGD's 2011 O&M costs per customer and O&M costs per unit of volume are within the lowest – best – quartile, and that the gap between average O&M costs per customer and O&M costs per unit of volume for the study group grew steadily between 2000 and 2011. (Exhibit A2, Tab 9, Schedule 1, pp. 84 to 86.)

The Concentric Incentive Ratemaking Report also demonstrates that EGD's 2011 Net Plant per customer and Net Plant per unit of volume are in the highest and third highest quartiles, respectively, but that the gap between average Net Plant per customer and Net Plant per unit of volume for the study group has been narrowing between 2000 and 2011. (Exhibit A2, Tab 9, Schedule 1, pp. 81 to 83.)

Thus, Enbridge ranks higher (better) on (a) O&M per customer and volume benchmarking than on (b) TFP-based total cost per customer and volume benchmarking because of the effect of Enbridge's capital cost per customer and volume on total cost per customer and volume. As demonstrated by Figure 5, below, only four companies in the study group added plant in recent years at a greater rate than Enbridge.

Figure 5 2001 – 2011 Plant additions as a Percent of 2000 Plant



During the 2001 to 2011 period a large component of plant additions for these 26 companies was (a) replacement of leak-prone pipe[3] and (b) new meters, services, and main extensions to serve new customers. Enbridge's high rate of plant additions is well-understood; Enbridge has been replacing leak prone pipe at a greater rate than other distributors and Enbridge has been adding customers at a greater rate than other distributors.

Specifically, since 2001, Enbridge has replaced approximately 1,000 km of leak-prone pipe; currently, virtually none of Enbridge distribution mains is leak prone. In contrast, most US distributors, including the study group companies, have been replacing leak prone pipe at a slower rate.[4] Also, Enbridge's 2001 to 2011 customer growth rate, 2.6%, was higher than all other companies in the industry study group.

[3] Leak-prone pipe generally includes cast iron, wrought iron and non-cathodically-protected steel mains and services.

[4] Related to this point, gas distribution cost models often include a measure of leak prone main in miles as a percent of total distribution mains, to reflect the effect of leak prone pipe on leak repair expense. However, gas distribution cost models should also include a measure to account for the accelerated replacement of leak prone pipe. Other things being equal, a gas distributor that has replaced its leak prone pipe at an accelerated rate will have greater additions to plant in recent years, and therefore higher total costs per customer than distributors that have significant leak prone pipe remaining to be replaced. Similarly, a gas distributor that does not have much leak prone pipe because it recently completed replacing its accelerated leak-prone pipe replacement program will have greater additions to plant in recent years and higher total costs per customer than a gas distributor that has never had much leak prone pipe.

In summary, Enbridge's TFP-based total cost rank must be considered against the limitations of using a TFP index, designed to compare trends in inputs/outputs for the purposes of absolute dollar comparisons. One must also consider company specific circumstances (e.g., accelerated leak prone pipe replacement) that drive capital investment levels.

Total Cost (Cdn$) Per Customer

Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Average 2000 - 2011
PSCO CO	297.41	328.97	317.21	285.78	206.09	145.70	134.94	168.62	179.72	285.85	268.44	221.19	236.66
Nicor IL	314.64	323.29	331.60	297.31	248.74	183.16	178.16	203.37	233.52	339.89	312.22	248.53	267.87
CenterPoint MN	329.75	345.77	343.98	312.74	248.91	203.17	187.27	221.69	237.36	320.55	283.08	255.16	274.12
Consumers MI	312.59	342.75	376.84	337.81	288.59	239.06	201.49	232.59	255.11	376.66	346.94	303.65	301.17
MGE MO	322.73	369.14	344.20	337.99	281.40	202.47	195.38	245.25	283.10	402.79	379.98	327.10	307.63
Columbia OH	430.98	388.52	321.49	292.30	252.67	223.95	232.77	267.66	297.55	416.89	372.76	284.46	315.17
WE WI	429.82	423.02	442.76	388.16	315.30	235.06	235.33	255.27	304.78	415.36	410.64	344.23	349.98
Ameren IL	428.38	451.98	464.80	403.70	318.44	233.38	254.25	282.04	311.01	429.11	382.34	311.38	355.90
BG&E MD	440.94	442.42	445.28	387.55	346.49	275.67	273.13	307.98	317.39	444.48	400.79	348.61	369.23
Laclede MO	409.57	455.12	466.54	426.88	356.36	285.47	277.02	310.66	348.41	485.58	436.70	365.49	385.32
Vectren IN	556.70	538.45	476.61	420.53	345.82	268.51	247.98	292.00	317.27	491.09	442.17	360.40	396.46
Dominion OH	413.38	407.75	412.43	334.28	280.20	264.10	317.67	381.14	444.00	531.64	550.94	477.15	401.22
NiSource IN	505.68	543.82	507.62	443.96	374.41	308.65	277.14	312.75	335.30	457.66	413.09	393.59	406.14
ENBRIDGE	416.21	364.00	463.36	441.54	357.37	381.08	412.28	351.33	374.36	406.16	463.11	514.83	412.13
PSE&G NJ	465.16	487.13	494.00	481.81	414.22	335.61	294.09	340.34	347.26	495.02	450.89	377.05	415.21
NWN OR	565.95	594.68	572.40	513.51	407.26	271.33	248.77	301.12	297.77	484.07	418.42	317.75	416.09
Questar UT	520.24	540.77	550.04	518.94	405.67	304.29	280.98	303.52	317.67	473.14	439.02	367.78	418.51
Puget WA	530.06	579.79	599.60	530.39	401.37	275.92	252.96	329.16	367.08	599.10	537.62	424.88	452.33
Iberdrola NY	608.01	598.08	628.25	536.61	445.68	357.07	310.00	333.86	357.10	540.96	502.44	467.44	473.79
WGL DC,MD,VA	611.75	640.44	665.81	563.86	450.19	337.66	306.81	343.00	366.36	533.48	482.78	404.79	475.58
ConED NY	587.03	599.79	598.37	526.03	425.24	328.45	318.54	353.06	404.40	615.50	629.20	530.21	492.99
DTE MI	546.02	740.78	696.00	643.17	553.28	399.39	355.18	396.21	478.19	618.18	559.42	468.51	537.86
National Grid MA	741.15	645.31	666.96	636.16	522.27	449.45	388.21	425.85	454.90	678.73	620.88	553.12	565.25
National Grid NY	714.04	716.95	746.27	692.64	536.39	414.05	370.21	405.05	441.03	654.59	609.33	516.89	568.12
Integrys IL	674.36	691.14	735.84	659.73	554.94	512.36	443.86	525.54	546.50	725.11	656.78	529.28	604.62
National Fuel NY	812.87	835.54	829.80	749.91	617.50	542.94	492.86	495.34	508.14	631.94	562.96	496.06	631.32
25 Company Average	502.77	521.26	521.39	468.87	383.90	303.87	283.00	321.32	350.04	497.90	458.79	387.79	416.74
Subgroup Average	482.88	484.13	495.48	453.15	366.07	284.42	259.79	291.42	314.89	460.21	426.41	359.53	389.86
Enbridge	416.21	364.00	463.36	441.54	357.37	381.08	412.28	351.33	374.36	406.16	463.11	514.83	412.13

Total Cost (Cdn$) Per Volume (10^3 m^3)													
													Average
Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2000 - 2011
NiSource IN	40.98	55.36	50.23	45.73	37.32	32.06	30.38	31.98	33.37	49.80	41.57	36.29	40.42
Nicor IL	41.46	47.85	45.62	43.69	38.84	29.23	28.76	33.16	35.98	54.79	52.87	41.48	41.14
PSCO CO	47.55	50.93	51.76	47.15	38.32	25.34	25.69	30.41	32.23	53.93	52.23	43.39	41.58
CenterPoint MN	53.83	61.14	56.46	52.30	43.08	36.79	35.95	38.61	40.76	60.79	55.83	50.62	48.85
Columbia OH	64.82	64.46	54.30	47.48	39.92	37.01	39.16	49.62	54.42	84.75	76.10	56.41	55.70
WE WI	65.15	71.75	71.73	62.29	54.02	39.03	42.32	42.76	49.71	70.89	73.03	60.05	58.56
ENBRIDGE	52.70	47.11	64.39	56.63	48.88	54.02	63.99	53.07	57.84	63.63	73.08	79.07	59.53
Ameren IL	70.98	78.98	78.18	66.57	56.66	41.63	48.75	52.76	53.96	78.44	67.43	55.13	62.45
Vectren IN	76.78	84.54	73.10	64.60	56.36	43.91	44.42	49.30	51.20	88.79	74.42	60.29	63.98
Dominion OH	58.28	67.93	65.10	52.38	44.10	41.68	55.02	62.80	71.11	97.01	92.41	76.68	65.37
MGE MO	40.23	119.00	43.44	51.25	64.82	47.19	50.77	58.19	61.05	94.29	87.62	79.28	66.43
Consumers MI	71.36	84.68	87.96	77.16	69.60	58.10	55.87	59.52	63.39	98.27	94.95	77.67	74.88
PSE&G NJ	57.23	76.63	75.35	69.92	80.14	67.92	66.24	69.72	73.17	102.13	95.32	76.61	75.86
NWN OR	86.51	99.01	98.81	93.83	74.63	50.23	46.17	56.19	55.24	100.89	93.34	65.89	76.73
Questar UT	85.85	91.30	96.98	104.87	82.06	65.03	59.09	57.26	56.12	88.26	82.62	69.49	78.24
BG&E MD	81.51	91.05	89.61	76.42	70.37	56.57	64.36	66.74	71.07	101.40	93.36	84.79	78.94
ConED NY	91.85	107.42	90.40	93.10	77.63	58.46	51.82	51.41	58.92	88.52	97.80	79.98	78.94
Iberdrola NY	96.99	106.39	108.77	87.94	76.15	62.55	60.75	60.48	64.61	100.92	98.11	90.67	84.53
Laclede MO	99.89	95.14	113.81	91.97	83.67	69.43	71.25	76.39	82.82	118.88	108.15	91.11	91.88
National Grid NY	99.15	104.81	109.94	109.19	97.00	72.50	67.27	68.39	79.19	117.50	105.80	87.64	93.20
Integrys IL	92.37	108.52	108.36	92.69	84.08	79.35	75.37	84.76	83.49	117.16	112.01	88.74	93.91
WGL DC,MD,VA	108.48	136.75	130.32	114.12	96.57	71.67	73.28	73.62	81.05	116.46	100.53	93.05	99.66
Puget WA	99.23	117.93	124.20	115.76	92.22	64.34	58.83	74.64	81.18	139.15	136.09	96.32	99.99
National Grid MA	125.43	112.17	115.38	111.07	96.81	92.91	77.96	81.23	93.44	145.08	99.40	79.35	102.52
DTE MI	67.97	98.58	147.01	125.18	117.29	97.12	101.04	102.41	120.45	163.29	163.01	128.21	119.30
National Fuel NY	136.83	151.77	147.58	129.53	114.03	102.90	104.97	96.79	102.43	132.22	121.90	104.55	120.46
25 Company Average	78.43	91.36	89.38	81.05	71.43	57.72	57.42	61.16	66.01	98.54	91.04	74.95	76.54
Subgroup Average	75.88	83.91	83.88	79.01	69.54	55.88	53.33	55.45	60.24	90.22	79.43	66.20	71.08
Enbridge	52.70	47.11	64.39	56.63	48.88	54.02	63.99	53.07	57.84	63.63	73.08	79.07	59.53

BOARD STAFF RESPONSE TO TCU1.11

In Undertaking TCU1.11 (Transcript 1 page 99) , Concentric Energy Advisors (CEA) was asked to provide the sum of capital costs and OM&A costs for each company in the sample, for the industry as a whole (the 25 US gas distribution companies), and for Enbridge, and to divide this sum by total customers. CEA was asked to perform this calculation for the 2010 and 2011 years.

In its response to TCU 1.11, CEA provided these calculations on average for the 2000-2011 period, rather than for each of the 2010 and 2011 years (the same years CEA highlighted in its benchmarking analysis).

Pacific Economics Group Research (PEG) was able to undertake these computations itself, using the data previously provided by CEA in advance of the Technical Conference. The tables below present the requested data for Enbridge and the 25 US gas distributors for the 2010 and 2011 years, respectively. In both years, companies are ranked in ascending order from one to 26 in terms of total unit costs (i.e. total cost per customer).

It can be seen that Enbridge's total cost per customer was $0.47 in 2010. This ranked Enbridge 15th of the 26 gas distributors in that year. Enbridge's total cost per customer was $0.53 in 2011, which ranks Enbridge 21st of the 26 gas distributors.

2010 Unit Cost Ranking

Rank	Company	Unit Cost
1	Public Service Company of Colorado (CO)	$0.27
2	CenterPoint Energy Resources Corp. (MN)	$0.31
3	Northern Illinois Gas Company (IL)	$0.32
4	Columbia Gas of Ohio, Incorporated (OH)	$0.37
5	Ameren Corporation (CILCO,CIPS,IP)	$0.39
5	Baltimore Gas and Electric Company (MD)	$0.41
7	Wisconsin Energy Corporation (We Energies) (WI)	$0.41
8	Southern Union Company (MO)	$0.42
9	Consumers Energy Company (MI)	$0.42
10	NiSource Inc. (IN)	$0.43
11	Vectren Corporation (IN)	$0.44
12	Questar Gas Company (UT)	$0.44
13	Northwest Natural Gas Company (OR,WA)	$0.45
14	Laclede Gas Company (MO)	$0.46
15	**Enbridge Gas Distribution**	**$0.47**
16	Public Service Electric and Gas Company (NJ)	$0.48
17	Iberdrola, S.A. (NY)	$0.48
18	Washington Gas Light Company (DC,MD,VA,WV)	$0.51
19	Dominion - East Ohio Gas Company (OH)	$0.52
20	Puget Sound Energy, Inc. (WA)	$0.54
21	DTE Energy Company (MI)	$0.58
22	National Fuel Gas Distribution Corporation (NY)	$0.59
23	National Grid (NY)	$0.62
24	National Grid (MA)	$0.63
25	Consolidated Edison, Inc. (NY)	$0.66
26	Integrys Energy Group, Inc. (IL)	$0.69

2011 Unit Cost Ranking

Rank	Company	Unit Cost
1	Public Service Company of Colorado (CO)	$0.24
2	Northern Illinois Gas Company (IL)	$0.27
3	Columbia Gas of Ohio, Incorporated (OH)	$0.30
4	CenterPoint Energy Resources Corp. (MN)	$0.30
5	Ameren Corporation (CILCO,CIPS,IP)	$0.33
6	Wisconsin Energy Corporation (We Energies) (WI)	$0.37
7	Northwest Natural Gas Company (OR,WA)	$0.37
8	Vectren Corporation (IN)	$0.37
9	Baltimore Gas and Electric Company (MD)	$0.37
10	Southern Union Company (MO)	$0.38
11	Questar Gas Company (UT)	$0.39
12	Consumers Energy Company (MI)	$0.39
13	NiSource Inc. (IN)	$0.40
14	Public Service Electric and Gas Company (NJ)	$0.41
15	Laclede Gas Company (MO)	$0.42
15	Puget Sound Energy, Inc. (WA)	$0.45
17	Washington Gas Light Company (DC,MD,VA,WV)	$0.45
18	Dominion - East Ohio Gas Company (OH)	$0.46
19	Iberdrola, S.A. (NY)	$0.47
20	DTE Energy Company (MI)	$0.51
21	**Enbridge Gas Distribution**	**$0.53**
22	National Fuel Gas Distribution Corporation (NY)	$0.55
23	National Grid (NY)	$0.56
24	Integrys Energy Group, Inc. (IL)	$0.59
25	Consolidated Edison, Inc. (NY)	$0.61
26	National Grid (MA)	$0.61

BOARD STAFF INTERROGATORY #13

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T9/S1/Incentive Ratemaking Report (CEA)/P 31 of 125

Concentric Energy Advisors writes that EGD's customer growth rate of 2.6% "is higher than all other companies in the industry study group."

a) Please provide the time period used to calculate the customer growth rate for EGD.

b) Please provide comparable customer growth rates for every other gas distributor in the industry study group, including the customer numbers for each distributor at the beginning and end of the sample period used to calculate customer growth.

RESPONSE

a) The time period 2000 to 2011 was used to calculate the customer growth rate for EGD.

b) The comparable customer growth rates, as well as number of customers at the beginning and end of the sample period used to calculate customer growth for every other gas distributor in the industry study group are shown in the table on the following page:

Company Name (State)	2000 Customer Count	2011 Customer Count	2000-2011 Growth Rate
CenterPoint Energy Resources Corp. (MN)	688,513	805,026	1.42%
Consumers Energy Company (MI)	1,594,484	1,707,987	0.63%
Baltimore Gas and Electric Company (MD)	596,644	653,154	0.82%
Laclede Gas Company (MO)	633,151	638,717	0.08%
National Fuel Gas Distribution Corporation (NY)	520,014	517,451	-0.04%
Northern Illinois Gas Company (IL)	1,962,235	2,184,884	0.98%
Columbia Gas of Ohio, Incorporated (OH)	1,365,431	1,396,393	0.20%
Northwest Natural Gas Company (OR,WA)	510,979	676,775	2.55%
Public Service Electric and Gas Company (NJ)	1,621,128	1,779,350	0.85%
Puget Sound Energy, Inc. (WA)	580,292	756,706	2.41%
Questar Gas Company (UT)	680,112	884,455	2.39%
Southern Union Company (MO)	487,304	491,794	0.08%
Public Service Company of Colorado (CO)	1,082,591	1,310,531	1.74%
Ameren Corporation (CILCO,CIPS,IP)	776,005	812,905	0.42%
Consolidated Edison, Inc. (NY)	1,167,055	1,198,027	0.24%
Dominion - East Ohio Gas Company (OH)	1,234,870	1,181,925	-0.40%
DTE Energy Company (MI)	1,219,275	1,230,396	0.08%
Iberdrola, S.A. (NY)	532,418	563,937	0.52%
Integrys Energy Group, Inc. (IL)	989,594	985,819	-0.03%
National Grid (MA)	747,037	857,035	1.25%
National Grid (NY)	2,212,152	2,350,183	0.55%
NiSource Inc. (IN)	755,378	838,311	0.95%
Vectren Corporation (IN)	624,857	673,311	0.68%
Washington Gas Light Company (DC,MD,VA,WV)	879,895	1,091,542	1.96%
Wisconsin Energy Corporation (We Energies) (WI)	943,586	1,064,144	1.09%[1]

[1] There was a formula error in the work paper that produced a slightly different growth rate for Wisconsin Energy Corporation (We Energies) (WI) of 1.17%. This difference is irrelevant to the outcome of the analysis.

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Is that correct?

MR. COYNE: Yes.

DR. KAUFMANN: Okay. So the question is whether -- I would like you to explain whether your decision to select peers using a proxy for unmeasured cold-weather variables that are not reported leads your peer-group selections to be biased, as you claim econometric-based benchmarks would be biased, when there are other factors that impact gas distribution costs that are not reported.

MR. COYNE: Well, let's break your question down to parts if we can. Let's start with the first piece of it. Is your question, can we feel confident that we have the appropriate sample, the first one, by using a heating degree day proxy group? Can we start with that? I think that was the -- you had a three-part question.

DR. KAUFMANN: Well, there's -- I think it's really just a one-part question, but there are various elements that -- kind of involved in that question, but ultimately the issue is the non-reported variable issue, and what you are saying in this response is that when there are factors that impact costs that are not reported, they lead to biases in econometric estimates; is that correct?

MR. COYNE: Well, or the inability to estimate them reliably.

DR. KAUFMANN: And yet you've relied on a proxy for various factors that are not reporting, and I'm just wondering whether --

MR. COYNE: The initial proxy group selection, yes.

DR. KAUFMANN: So you have -- you're acknowledging that there are various factors that are not reported, and yet you have something that is a proxy that's associated with that, and the question is whether relying on proxies for variables to select peer groups that are not reported, whether the same biases are introduced when we're talking about variables that are not reported in peer group benchmarking as would be -- as you say exist in econometric benchmarking.

MR. COYNE: Well, put it this way. We're not introducing a bias in doing so. By selecting a 25-company proxy group based on weather, we start, I believe, with a reasonable position in terms of companies that face operating circumstances to Enbridge. What we're not suggesting in doing so is that we have the ability to parse on each of these variables the specific cost drivers reached at those utilities. So what we're forced to do is treat them as a group.

Are there biases in that proxy selection? Well, are they a perfect measure for Enbridge? I would say no, but I think it's a reasonable way to choose such a group. Again, as I've indicated, I see other studies that use the entire universe of North American utilities or US utilities, and I see no reason to do that when you can choose a group that's at least more like your target company.

As is known by this audience, I do a fair amount of work that relies on similar standards for cost of capital, and when you are doing cost of capital work, you start with the same -- you start with selection criteria to choose a smaller group from a broader group, based on reasonable criteria. And I would argue that weather is an important one, but then we go on from there to use customer size because we're trying to get at scale economies, and we use customer growth because we know that customer growth is also a significant factor impacting total factor productivity.

It might be helpful, so that we're not talking in the abstract here, to introduce a visual that I pulled together last night, thinking that this issue might come up. If I could get some help in distributing these, I'll share them with my panellists so that we're not talking in the abstract about this principle. Maybe I should wait a moment until everybody has it in front of them.

So what you have is a visual representation of our selection rationale, and by choosing weather as our proxy group, what we've done is included natural gas utilities that operate in the greyed states that you can see there.

Thank you for getting that up so quickly overhead. Impressive.

And so you can see the states that we chose, and then within those states you can see the specific utilities that we've chosen. And those utilities are, A, natural gas utilities. They are not electric companies, or we've chosen the natural gas utility portion of combination companies where we had the data.

The weather, they're the northern US, and as I mentioned, they're plus or minus 45 percent of the degree days of Enbridge as a limit. But on average, they are 7 and 8 percent within Enbridge's heating degree days.

They're the largest gas distributors in this region. They're all over 500,000 customers. And that number is greater for our seven-company group; it's greater than 850,000 customers. And there, they're also the fastest growing.

And lastly, there are those companies that we had quality available data for to conduct the analysis. So those are the screens that we used to create this initial proxy group.

Had we started off -- to go further than that and to suggest that we -- if we had access to this data for individual companies, to begin to parse that further econometrically, again, the data's not available to do so. Had it been available to us, perhaps we would have experimented with it, but again, it wasn't available to us, and therefore we can't draw those conclusions.

But certainly insofar as this work goes, we're confident that we have a reasonable set of utilities to begin with. And again, I think the seven-company subgroup, which creates more of a stretch for Enbridge, is even more representative.

DR. KAUFMANN: Okay. Why don't we go on to page 3 of this response? Jay, do you have a question?

QUESTIONS BY MR. SHEPHERD:

MR. SHEPHERD: It took me such a long time to

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understand how business conditions fit in your --- it's upsetting me that I'm now confused again.

As I understand it, whenever you try to do benchmarking you have to identify the primary cost drivers, and correct for those if you are comparing somebody to any other benchmark, right? You have to correct for the cost drivers?

MR. COYNE: Well, not necessary. You can approach it a couple of different ways.

One is you start by selecting a peer group that is comparable, and therefore you assume that they are facing similar cost drivers.

MR. SHEPHERD: That's what I'm getting to, Mr. Coyne.

My understanding was that when you do peer group benchmarking, you take those cost drivers and you use them, the main cost drivers, and you use them to select your peer group. And that way you have a fair comparison.

When you use econometrics, you take those cost drivers and you build them into a formula that predicts costs, but you're still using the same cost drivers, right? In both cases?

MR. COYNE: I agree with you in the latter, in terms of how you're describing the econometric analysis.

But for a pure peer group benchmarking analysis, it's not necessary to understand the cost drivers, if you have other criteria that suggest that they should be living in a similar operating environment.

When you do -- industry benchmarking happens not just

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Exhibit K1.5

here, for utilities, of course; all kinds of industries benchmark their operation. The standard way to do benchmarking analysis isn't what's done in these regulatory contexts. It's to select a group of peers that have similar operations.

I used to do this for refining companies and chemical companies. You choose polypropylene plants. You choose refineries that are cracking the same type of crude oils to do refineries, et cetera. So you have those selection criteria that allow you to create a proxy group.

You assume that because of those operating characteristics that you have, you have the appropriate cost drivers behind them and therefore you can make legitimate comparisons.

MR. SHEPHERD: That's the question I'm asking. When you choose your selection criteria, isn't the purpose of doing that to ensure that the businesses that are being compared have similar major cost drivers? Isn't that the purpose of it?

MR. COYNE: Yes, it is.

MR. SHEPHERD: So if you're selection criteria in peer group benchmarking misses major cost drivers or business conditions that represent major cost drivers, then isn't it biased?

MR. COYNE: I wouldn't say biased, but I would say it's not as robust a peer group as it could be if you had some that were closer to your target company. That's always the objective when you're benchmarking, is to come

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up -- two-fold.

One is you want a big enough group so you are not looking at just two other companies. For example, here we could say let's just look at Union, but we don't know if Union can tell us what top quartile performance is, for example. By looking at a larger group, we can derive a broader sample from the industry and learn more from it, which we're trying to do, but you don't want to be so broad -- i.e., the entirety of North America -- that you include companies -- for example, Californian utilities are not included in our sample size because of the weather conditions that they face. Even though they're large companies, we just don't think they operate in Enbridge's operating environment.

MR. SHEPHERD: But weather conditions are only a proper selection criteria if they reflect a major cost driver, they represent a major cost driver for a gas utility, right?

MR. COYNE: yeah. That is correct.

MR. SHEPHERD: Thank you.

MR. COYNE: And in that response, we denote what we believe that weather represents by way of a group of cost drivers, everything from system design day to their ability to get out in the field and prepare repairs, et cetera. We had a discussion with Dr. Kaufmann regarding those this morning.

MR. SHEPHERD: Thank you.

QUESTIONS BY MR. BRETT:

MR. BRETT: Can I just add one question to that? I also heard you say, Mr. Coyne, that in looking at this map here, you say they had common weather conditions, but you went on to say they also have comparable size, comparable growth patterns. So you're introducing a number of -- there's a number of criteria that you are using here in making your 25- and seven-company selection, peer-group selections. So it's not just weather that you are using. You are using several criteria, correct?

MR. COYNE: That's correct, yes. Thank you.

MR. BRETT: But you don't spell out in your -- all right. That's fine.

MR. COYNE: We do in the testimony, and if you look at the bottom of the map here you can see these other -- this is -- these criteria go to the 25, so what's missing there are the additional criteria that we used to get to the seven, and that was an even larger-sized company that's growing faster in order to even better approximate Enbridge than the broader group. But you are correct in pointing out it wasn't just weather that we used for screening criteria.

QUESTIONS BY DR. KAUFMANN:

DR. KAUFMANN: Okay. Two follow-up questions based on that response. The other major factor that you used to screen was size. Isn't that correct?

MR. COYNE: Yes.

DR. KAUFMANN: Okay. And the size criteria was to include only U.S. utilities that had at least 500,000 haven't had a chance to review yet and showing me select sentences.

But I will acknowledge, as we did in our testimony, that the Board has relied on econometric modelling for purposes of determining stretch factors. And I think the Board is in a position there, with having collected a more robust data set for electric distributors, to begin to explore what can be done econometrically.

If the suggestion is made that the Board is in the same position here, that is simply not the case, and if it were to put -- if it were -- attempt to do so here, would it rely on data for Enbridge and Union to create an econometric model? I don't think anyone would agree that that's a robust enough data set to do that with.

So we're back to the same place we are in our response in CME 1, that you don't have the data available to you to do that, but I will acknowledge the reliance as expressed in this report that the Board has placed on econometric benchmarking for purposes of electric distributors.

DR. KAUFMANN: Okay. You said that if they relied on -- only on Enbridge and Union data, then that wouldn't be enough data. If they relied on a U.S. sample, as you did for your benchmarking, would that potentially lead to a reliable benchmarking -- econometric benchmarking --

MR. COYNE: Well, if you --

DR. KAUFMANN: -- approach?

MR. COYNE: I go back to where we began this conversation. If you had a robust enough data set, then I think one could begin to explore econometric benchmarking, yes.

DR. KAUFMANN: Okay. Thank you.

MR. COYNE: But that data is not available.

DR. KAUFMANN: That's all.

MS. SEBALJ: So I assume this is a good time to take a 15-minute break, and then, Mr. Shepherd, are you next on the -- do we want to do this right now or right after the break? After the break. Okay. So we'll look at the SEIM hypothetical example after the break, and then move on with questions. 15 minutes? Quarter to three? Is that good? Thanks.

--- Recess taken at 2:31 p.m.

--- On resuming at 2:49 p.m.

MS. SEBALJ: So in the interest of time, did we want to start back up again? I guess I'll turn it over to Enbridge to speak to the document that was just distributed.

MR. CASS: I would propose that perhaps the document be given an exhibit number. Then the panel will walk through it. MS. SEBALJ: Sure. It's TC1.5.

EXHIBIT NO. TC1.5: DOCUMENT PROVIDED BY EGDI

MR. CASS: Thank you. I'll turn it over to the panel.

MR. FISCHER: Thank you, Mr. Cass. So what we were trying to do with this illustration was to detail the essential four steps as we see it, in terms of, first of all, determining what a SEIM reward amount would potentially be, as well as the application of two tests

TC1.4

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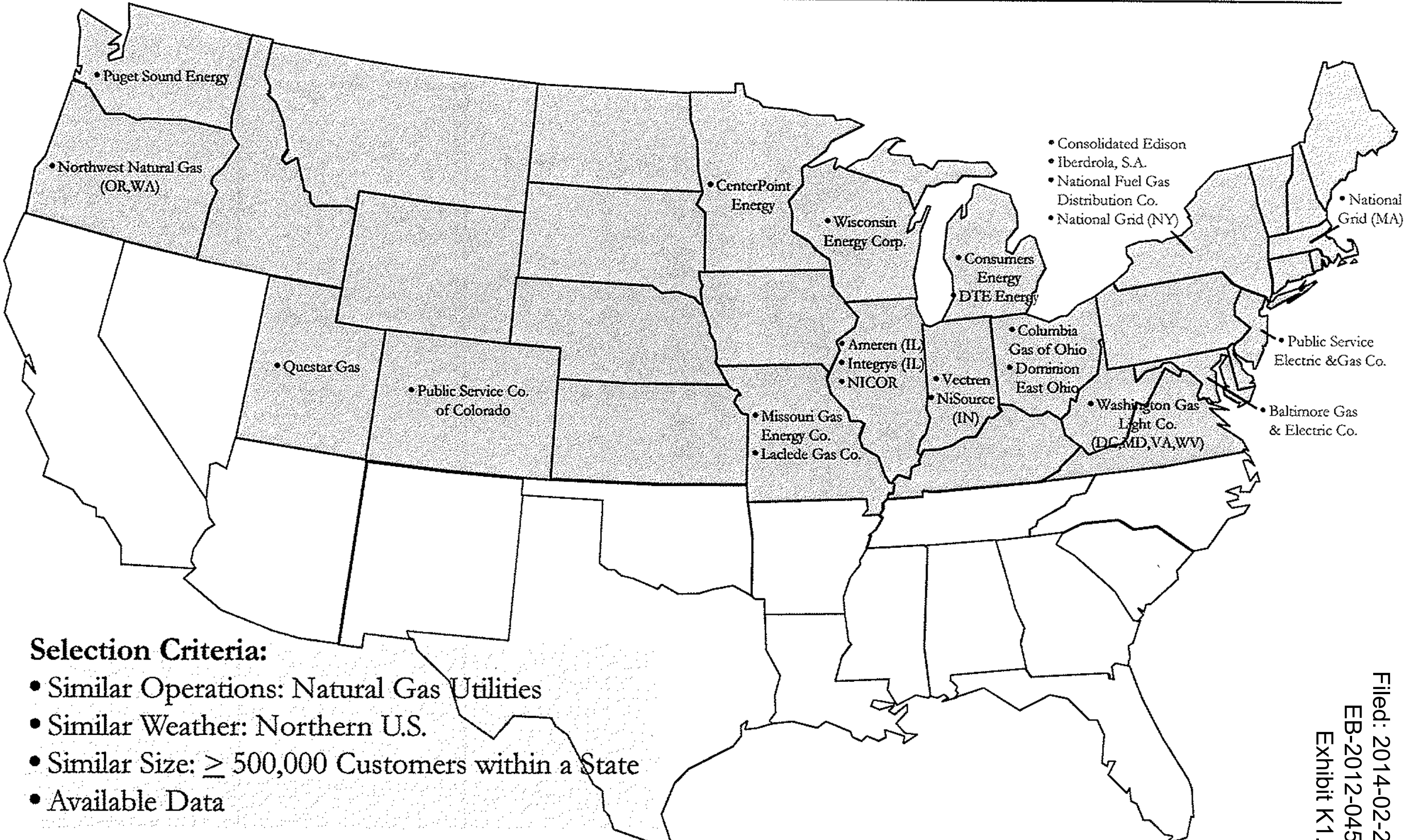
Exhibit K1.5

States Selected for Industry Study Group



Selection Criteria:

- Similar Operations: Natural Gas Utilities
- Similar Weather: Northern U.S.
- Similar Size: $\geq$ 500,000 Customers within a State
- Available Data

TC1.4

SEC INTERROGATORY #50

INTERROGATORY

Issue A10: 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
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, p. 1] *"Over the past decade the Company has benchmarked its performance with peer utilities across various aspects of the business."* Please provide those benchmarking studies or reports. If the content in response to this interrogatory is greater than 100 pages, please provide a list with sufficient description of each to allow parties to understand which such studies or reports are likely to be relevant and material in the context of this Application.

RESPONSE

Table 1 on the following pages provides a listing of benchmarking studies or reports that the Company participated in over the past decade. The content in response to this interrogatory would be significantly more than 100 pages.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

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Exhibit K1.5

Table 1
Description of the Benchmarking Studies or Reports that the Company has participated over the Past Decade

Metrics	Description of Benchmarking Studies or Reports
Customer Satisfaction Index	1. 2004 Corporate Reputation and Image Study. The Company conducted a survey by comparing the Company's reputation and image with Natural Gas Resellers/Brokers, Electricity, Cable TV and Local Telephone companies.
	2. 2005 Corporate Reputation and Image Study. Please refer to #1 above for the description.
	3. 2004-2007 Customer Satisfaction Research. The purpose of the study is to monitor customers' impressions, expectations, perceptions and performance assessments of their experience with the Company based on various interaction points. The Company's results are then compared with Electricity, Cable/Satellite and Local Telephone companies.
	4. 2007 Corporate Reputation Customer Research. The Company conducted a survey by comparing the Company with Natural Gas Resellers/Brokers, Electricity, Cable/Satellite TV and Local Telephone companies.
	5. 2008-2011 Customer Satisfaction Research. Please refer to #3 above for the description.
	6. 2009-2011 Corporate Reputation Customer Research. Please refer to #4 above for the description.
	7. 2006-2008. Canadian Electricity and Gas Distributors Benchmarking Study conducted by Ipsos Reid. The purpose of the study was to compare the Company's residential energy customer satisfaction and reputation perception among Canadian electric and natural gas distributors.
	8. 2012-2013 Gas Utility Residential Customer Satisfaction Study and Gas Utility Business Customer Satisfaction Study. J.D. Power and Associates conducted the satisfaction study by ranking the Company against 75 natural gas utilities. Research is conducted online over 4 quarterly fielding periods for complete annual and seasonal perspectives.
	9. 2013 Utility Website Evaluation Study. J.D. Power and Associates conducted the study by evaluating the Company's website with large US natural gas and electric utilities.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

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Metrics	Description of Benchmarking Studies or Reports
	10. 2013 Esource Web and Interactive Voice Response ("IVR", or Automated Telephone System) Study. Esource conducted this study by evaluating the Company's website and IVR performance against American and Canadian electric and natural gas utilities. 11. 2012 Customer Satisfaction Research and Corporate Reputation Customer Research. The Company conducted a survey by comparing the Company's customer satisfaction and reputation performances with Natural Gas Resellers/Brokers, Electricity, Landline or Home Phone, Cell Phone, Cable/Satellite TV and Bank/Financial institutions. 12. 2013 Corporate Reputation Customer Research. The Company is currently conducting a survey by comparing the Company's reputation with Natural Gas Resellers/Brokers, Electricity, Landline or Home Phone, Cell or Smart Phone, Cable/Satellite TV and Bank/Financial institutions.
Employees Health and Safety	1. The Company has participated in the American Gas Association ("AGA") annual Safety and Occupational Health summary since the organization's inception in 1993. This summary covers both worker and vehicle safety data such as number of injury and vehicle accidents. The report provides comparative statistics of all participating AGA companies, grouped by company size in addition to detailed injury and accident analysis. The output of this annual report determines the AGA Safety Award recipients. 2. The Company has participated in the Canadian Gas Association ("CGA") Quarterly Health and Safety Statistic Report Form submission since 1996 by providing worker and vehicle safety data such as number of injury and vehicle accidents. The report provides comparative statistics of all participating CGA companies. The output of this annual report determines the CGA Safety Award recipients.
Damage Prevention, Leak Management, Outages	1. 2007-2012 Annual Damage Information Reporting Tool ("DIRT") Reports. The DIRT Report provides a data comparison between Ontario utilities and other American utilities and root cause analysis of damages, number of damages, and ratio of damages per 1,000 locate requests. Reports are available to the public from the Ontario Regional Common Ground Alliance ("ORCGA") web site.[1] Since 2007, the Company has participated along with other members (which include gas, electric and municipal utilities) in submitting data to ORCGA for the creation

[1] http://www.orcga.com/StaticTeaserTemplate.asp?itemCode=PUBLICATIONS-AND-RESOURCES&CssPath=css/TeaserTemplateSample/PublicationsResources.css&CssDivID=PublicationsResources&TeaserLength=100&Path=/StaticTemplate.asp&title=Publications

Witnesses: I. Chan
S. Kancharla
I. MacPherson

Filed: 2014-02-25
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Exhibit K1.5

Metrics	Description of Benchmarking Studies or Reports
	of the annual DIRT report. The Company was a founding member of the ORCGA back in 2003. ORCGA is a nonprofit organization dedicated to shared responsibility in damage prevention and in the promotion of damage prevention Best Practices. In 2013, the Company was presented with an award for 10 years of support as a Gold Level sponsor. In June 2012, the Ontario Legislature passed Bill 8, the Ontario Underground Infrastructure Notification System Act, a new law to establish a mandatory "Call Before You Dig" regime in Ontario. ORCGA and the Company were active in support of the legislation's passage. Figure 1 of Exhibit D1, Tab 17, Schedule 1, Page 8, illustrates that the Company has been successful in reducing total number of damages. There has been a 47% reduction in number of damages between 2003 and 2012. 2. The Company has participated in the AGA Gas Utility Operations Best Practices Program since the organization's inception in 1993. Examples of this program are Damage Prevention, Leak Management, Employee Safety, etc. This program provides a forum for the identification of procedures and practices that can improve the reliability, safety and cost-efficiency of a company's operations. Program participants have the opportunity to learn of practices effectively implemented, and new innovative practices that are being utilized, by industry leaders in different aspects of natural gas operations. The AGA Operations Best Practices Program is intended to highlight how particular companies may address a specific operational issue and may not include all of the data related to a highlighted practice. The need to implement and the timing of any implementation of highlighted practices will vary with each utility operator. Each utility operator serves a unique and defined geographic area and their system infrastructures vary widely based on a multitude of factors, including, condition, engineering practices and materials. Each utility operator needs to evaluate highlighted practices in light of their system variables. Not all highlighted practices will be applicable to all utility operators due to the unique set of circumstances that are attendant to their specific systems. Companies are not ranked through this program and no one practice is identified as the best for a particular topic. 3. The Company has participated in the Gas & Electric Utility Peer Panel program since 2007. It is an independent program, fully operated and funded by Public Service Electric and Gas Company ("PSE&G"). This program includes the same topics annually, and produces report, Gas Delivery, Benchmarking Study, that enable the participants to trend their results against both the participants and themselves year over year.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

Metrics	Description of Benchmarking Studies or Reports
Operating and Maintenance Cost ("O&M")per Customer	1. Cost Per Customer. RP-2002-0133, Exhibit A6, Tab 1, Schedule 2. The Company provided a comparison of the Company's O&M cost per customer with a benchmark (average) of gas and gas/electric utilities in the United States for fiscal year ended September 30 over the 1992 to 2000 time period. 2. Benchmarking Study. EB-2011-0354, Exhibit A2, Tab 1, Schedule 2. Concentric benchmarked the Company's O&M per customer against the U.S. and Canadian peer group in 2009 and 2010 and the U.S. peer group over the 2000 to 2010 time period. 3. Incentive Ratemaking Report. Exhibit A2, Tab 9. Schedule 1. Concentric benchmarked the Company's O&M cost per customer in the industry study group for 2011 and against the industry study group average over the 2000 to 2011 time period.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #51

INTERROGATORY

Issue A10: 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
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, p. 2] Please explain why the Applicant proposes to file performance benchmarking data only at the end of the IR term, rather than annually.

RESPONSE

As stated at Exhibit A2, Tab 11, Schedule 2, page 5, paragraph 14, the purpose of 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 the Company's, as appropriate.

Given that the availability of benchmarking data may be made available with a one-year lag and/or at an unspecified date, filing the performance benchmarking data annually as part of the annual Earnings Sharing Mechanism application will not be feasible. Moreover, as the purpose of the benchmarking is to assess the direction and trending of metrics, it will require at least three years of actual benchmarking results in order to enable the Company to conduct meaningful year over year analytics in the direction and trending of the relevant metrics.

In view of these practical considerations, the most useful benchmarking comparisons will be available at the end of the IR term.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #52

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

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g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, p. 9] Please explain why Operating and Maintenance Cost per Customer is to be reported and benchmarked, but there is no equivalent reporting or benchmarking of capital expenditures.

RESPONSE

The reasons for reporting the Operating and Maintenance Cost ("O&M") per Customer metric and not the Capital Expenditures ("CAPEX") per Customer measure is because O&M per Customer is a reasonable and generally accepted basis to compare performance among different utilities, subject to recognition of factors that account for explainable differences in O&M cost per customer.

It is more challenging to benchmark capital expenditures than O&M as capital expense benchmarking cannot meaningfully account for difference in capital plans between utilities related to system expansion, system reinforcement, and system replacement. Also, this utility specific information on capital expenditures is usually not easily or readily available from public documents. Conversely, utility O&M expenses are typically readily available, comprised of elements such as employee (e.g., salaries, benefits, pension, etc.) and customer care related expenses for which the underlying measurement definition is relatively standard and largely consistent across utilities.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

As stated in Exhibit A2, Tab 11, Schedule 2, page 6, the corresponding implementation costs[1] would not outweigh the value for the metrics to be reported and benchmarked.

[1] 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.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #53

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
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d. Treatment of Cost of Capital
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f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, App. 3] Please provide a comparison of the proposed benchmarking metrics with the Applicant's corporate scorecards for senior executives. Please provide a rationale for any material differences between the two.

RESPONSE

The proposed Benchmarking Report as stated at Exhibit A2, Tab 2, Schedule 11, and the Corporate Scorecard for all employees as described in the Employee Expenses and Workforce Demographics evidence at Exhibit D1, Tab 3, Schedule 2, have different purpose, focus, and usage. Therefore, it is important to understand the differences from a conceptual framework perspective first. These conceptual differences are summarized in Table 1 on the next page.

In sum, the purpose of the Benchmarking report is to compare the benchmarking metrics proposed in Exhibit A2, Tab 2, Schedule 11, Appendix 3, against comparable peer regulated utilities in terms of direction and trending. It is an ongoing activity and it is not a one year or annual event. 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 metrics reported here are outcome based metrics or lagging performance indicators to reflect the utility outcomes of the Company's strategic objectives. The metrics also have to be currently supported or published by reputable external benchmarking publications.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

The Company's Corporate Scorecard is used as a measurement of organizational performance including utility and non-utility operations for the year. The purpose of the scorecard is to align business and employee objectives. It is a conceptual framework for translating an organization's objectives into a set of leading and lagging performance indicators.

Table 1
Summary of the Conceptual Framework differences between the Benchmarking Report and the Corporate Scorecard

	Benchmarking Report	Corporate Scorecard
Purpose or Goal	▪ Best practices benchmarking ▪ Trend and direction comparison	▪ Performance measurement and management
Focus	▪ EGD regulated operations only ▪ Exclude Non-Utility and Subsidiaries	▪ Enbridge East operation ▪ Include Non-Utility and Subsidiaries: New Brunswick, St. Lawrence and Gazifere.
Rationale of the Metrics	▪ Common or standard metrics that are published by external benchmarking publications ▪ Reflect the outcomes of the strategic objectives, i.e. lagging performance indicators.	▪ Reflect the progress towards to achieving the strategic objectives, i.e. leading performance indicators ▪ Reflect the outcomes of the strategic objectives, i.e. lagging performance indicators
Evaluation Timeframe	▪ Minimum 3+ years horizon ▪ Continuous trend and direction monitoring	▪ Annual horizon

Tables 2 to 4 provide a comparison with explanation of the proposed benchmarking metrics with the Company's Corporate Scorecard metrics among three categories: customer relationship, operational performance and financial performance. As can be seen, there are substantial similarities between the Benchmarking Metrics and the Corporate Scorecard.

Table 2 on the following page presents the customer relationship category comparison. The Service Quality Requirements ("SQR") metrics are not reported on the Corporate Scorecard as these metrics have been established by the Board to track the gas utility's service quality performance and are therefore already embedded into the mandatory

Witnesses: I. Chan
S. Kancharla
I. MacPherson

performance objectives. It is beneficial for the Company to benchmark these SQR metrics against the other Ontario gas utilities from a trend or direction comparison perspective understanding each utility operator serves a unique geographic area, unique customer mix, and unique operational circumstances.

Table 2
Customer Relationship Category

Benchmarking Metrics	Corporate Scorecard Metrics
• Customer Experience: Customer Satisfaction Index	• Customer Experience: Customer Satisfaction Index
• Call Answering Service Level (SQR)	
• Percentage of Emergency Calls Responded to within One Hour (SQR)	
• Meter Reading Performance Measurement (SQR)	
• Appointments Met within the Designated Time Period (SQR)	
• 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)	

Table 3 on the next page illustrates the operational performance category comparison. As detailed in the Pipeline Integrity and Engineering evidence at Exhibit D1, Tab 17, Schedule 1, Page 1, recent industry events or regulatory expectations, such as the natural gas explosion in San Bruno, California (2010), and the Technical Standards and Safety Authority Code Adoption Document FS-196-12, which came into effect November 2012, have caused the Company to reexamine and enhance its work practices to further prevent incidents, and improve environmental, worker and public safety. This has led to the Company's increasing focus to further reduce operational risks, with a goal of further reducing incidents and injuries. Therefore, the metrics reported on the Corporate Scorecard are mainly leading performance indicators. They are used to measure the organization's progress towards achieving the Pipeline Integrity and Engineering business objectives stated in the evidence.

Table 4 on the next page presents the financial performance category. As the Company's Corporate Scorecard is used as a measurement of organizational performance including utility and non-utility operations for the year, net earnings is the usual metric for measuring financial performance. Operating and maintenance ("O&M")

Witnesses: I. Chan
S. Kancharla
I. MacPherson

cost per customer, return on equity and interest coverage ratios are included in the proposed Benchmarking Reporting in order to provide a balanced view of the Company's financial performance when benchmarking its performance against other utilities'.

Table 3
Operational Performance Category

Benchmarking Metrics	Corporate Scorecard Metrics
• Damage Prevention: Number of Excavation Damages per 1,000 Locates	• Damage Prevention: Number of Excavation Damages per 1,000 Locates
• Leak Management: Service Leaks Repaired per Mile of Service	• % of Leaks found through Leak Survey
• Leak Management: Total Number of Grade 1 (A) leaks eliminated or repaired during the year	• Leak year-end average exit rate (days)
• Employees Health and Safety: Total Reportable Injury Frequency Rate	• Employees Health and Safety: Total Reportable Injury Frequency Rate
• Operational Effectiveness: All outages per 1,000 Customers	• Motor Vehicle Incident Frequency Rate
	• Safety Observations
	• Environment, Health and Safety Required Courses Training Attendance
	• Verify Maximum Allowable Operating Pressure on Targeted Lines – Delivery to Plan
	• % of High Stress and Targeted Pipelines Inspections Completed
	• Significant Incident / Asset Rupture

Table 4
Financial Performance Category

Benchmarking Metrics	Corporate Scorecard Metrics
• Financial Efficiency: Operating and maintenance cost per customer	• Net Earnings - Utility and Non-Utility
• Return on Equity	
• Financial Obligations Met: Interest Coverage Ratios (Legal Entity)	

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #52

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

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k. Treatment of Customer Care and CIS costs

[A2/11/2, p. 9] Please explain why Operating and Maintenance Cost per Customer is to be reported and benchmarked, but there is no equivalent reporting or benchmarking of capital expenditures.

RESPONSE

The reasons for reporting the Operating and Maintenance Cost ("O&M") per Customer metric and not the Capital Expenditures ("CAPEX") per Customer measure is because O&M per Customer is a reasonable and generally accepted basis to compare performance among different utilities, subject to recognition of factors that account for explainable differences in O&M cost per customer.

It is more challenging to benchmark capital expenditures than O&M as capital expense benchmarking cannot meaningfully account for difference in capital plans between utilities related to system expansion, system reinforcement, and system replacement. Also, this utility specific information on capital expenditures is usually not easily or readily available from public documents. Conversely, utility O&M expenses are typically readily available, comprised of elements such as employee (e.g., salaries, benefits, pension, etc.) and customer care related expenses for which the underlying measurement definition is relatively standard and largely consistent across utilities.

As stated in Exhibit A2, Tab 11, Schedule 2, page 6, the corresponding implementation costs[1] would not outweigh the value for the metrics to be reported and benchmarked.

[1] 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.

TC1.5

TC1.5

[redacted]

<u>Numerical illustration</u>

A. SEIM Reward Potential (ROE Premium) for each of 2019 and 2020
= (10.5% - 10%)*50%*50%
= **0.125%**

B. ROE Premium% for each of 2019 and 2020
= Min[**0.125%**,0.5%]
= **0.125%**

C. ROE Premium $ for each of 2019 and 2020 $3.6 million
= $4 billion*36%***0.125%**
= $1.8 million for each of 2019 and 2020 [redacted]

D. Revenue Premium $ for each of 2019 and 2020
= $1.8 million/(1-0.265)
= $ 2.5 million for each of 2019 and 2020

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I. NPV* of benefits from the Productivity Initiatives Report for projects undertaken between 2014-2018 > $3.6 million (SEIM reward potential earnings)

2018 Productivity Initiatives Report

Initiatives or Projects Net Benefits ($ Millions)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total NPV
A				$(14)	$0.5	$1.5	$2	$3	$4	$5	$2
B	$(2.5)	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5			$1
C					$(3)	$1	$1	$1	$1		$1
D			$(5)	$(2)	$0.5	$1.5	$2	$2	$2		$1
Total	$(2.5)	$0.5	$(4.5)	$(15.5)	$(1.5)	$4.5	$5.5	$6.5	$7	$5	$5

NPV of Benefits from the Productivity Initiatives Report:
= $2 +$1 +$1 +$1million = $5 million > $3.6 million

*The NPV of the net benefits will be determined using the same financial parameters (capital structure, cost of capital, tax rates, etc.) as are used for customer additions feasibility analysis

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III. Maintain at or above the 2013 level of EGD's overall SQR performance for at least three of the five years during 2014-2018. To be permitted to recover the SEIM reward, on average EGD must meet or exceed its 2013 SQR performance in at least 3 of the 5 years of the IR term.

SQR Metrics	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Years at/or above
Call Answering Service Level	78.4%	78.5%	78.6%	78.7%	78.8%	78.9%	5
Percentage of Emergency Calls Responded to within One Hour	96.9%	96.9%	97%	97%	97%	98%	5
Meter Reading Performance Measurement	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	5
Appointments Met within the Designated Time Period	93.3%	*92%*	*92%*	94%	94%	94%	3
Time to Reschedule a Missed Appointments	93.8%	93.8%	93.8%	93.8%	93.8%	93.8%	5
Number of Days to Reconnect a Customer	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	5
Number of Days to provide a Written Response	83.14%	*82%*	84%	85%	85.5%	86.6%	4
Number of Calls Abandon Rate	2.4%	2.3%	2.3%	2.2%	2.2%	2.2%	5
Average							4.625

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think one could begin to explore econometric benchmarking, yes.

DR. KAUFMANN: Okay. Thank you.

MR. COYNE: But that data is not available.

DR. KAUFMANN: That's all.

MS. SEBALJ: So I assume this is a good time to take a 15-minute break, and then, Mr. Shepherd, are you next on the -- do we want to do this right now or right after the break? After the break. Okay. So we'll look at the SEIM hypothetical example after the break, and then move on with questions. 15 minutes? Quarter to three? Is that good? Thanks.

--- Recess taken at 2:31 p.m.

--- On resuming at 2:49 p.m.

MS. SEBALJ: So in the interest of time, did we want to start back up again? I guess I'll turn it over to Enbridge to speak to the document that was just distributed.

MR. CASS: I would propose that perhaps the document be given an exhibit number. Then the panel will walk through it. MS. SEBALJ: Sure. It's TC1.5.

EXHIBIT NO. TC1.5: DOCUMENT PROVIDED BY EGDI

MR. CASS: Thank you. I'll turn it over to the panel.

MR. FISCHER: Thank you, Mr. Cass. So what we were trying to do with this illustration was to detail the essential four steps as we see it, in terms of, first of all, determining what a SEIM reward amount would potentially be, as well as the application of two tests that we propose that are based on assessment of metrics over the IR term on whether the SEIM award will be, in fact, awarded at the end IR term.

So in slide 2, we start off what the steps are in terms of the formula. So step A, in terms of the derivation of the reward dollar amount itself, is to determine what the ROE percentage premium is over the IR term. And that's done by calculating what the average ROE over the IR term is, and subtracting from that what the average of the Board-approved ROE is over the IR term.

MR. QUINN: Is that the weather-normalized actual, or "actual actual"?

MR. FISCHER: That's the actual -- sorry, it's the weather-normalized.

MR. QUINN: Weather?

MR. FISCHER: Yes, it is. In terms of the Board-approved ROE, we're using the 2009 formula, ROE formula, and that's consistent with the formula that we're using for ESM purposes as well. It's also the same formula that we've used to actually calculate our forecast return on equity over the IR term as well.

So that difference between those two averages is multiplied times 50 percent, and then 50 percent again, and then a percentage is derived.

So moving to step B is comparing what the derived percentage is, and comparing that to the maximum allowed, which is 50 basis points, or 0.5 percent. So the minimum would be either 0.5, or if it's less than 0.5, that would be the ROE premium percentage that would apply.

MS. GIRVAN: Can I just ask a question? What assumption have you made with respect to what regulatory model will be in place in 2019 and 2020?

MR. FISCHER: We aren't making an assumption because we don't know. We do think that in 2019 we'll be in a rebasing year. So whatever revenue is determined for that year as part of the rebasing application, ultimately the SEIM award in terms of the revenue amount would be added to that, whatever is determined in that proceeding. And then for 2020 it's an open question in terms of what could occur during that year, whether in cost of service --

MS. GIRVAN: So it doesn't matter, from your perspective?

MR. FISCHER: No, it doesn't.

MS. GIRVAN: Thanks.

MR. FISCHER: So moving to step C, then, in terms of the formula, so the ROE premium dollar amount is determined for -- and it's the same dollar amount that we applied, as I just talked about, for 2019 and 2020. So the -- what's used is the 2019 utility rate base times the 2019 utility equity ratio, and then the percentage, the ROE premium, 50 basis points or less, is applied to that to determine the dollar value of the ROE premium.

MR. QUINN: You paused, Ralph, but you said 50 basis points or less, but I thought --

MR. FISCHER: So the maximum is 50 basis points in terms of the difference between the average allowed and average actual ROE over the IR term, so it won't be any more than 50 basis points.

MR. QUINN: Then I'm reading something wrong here. It says minimum reward potential is 0.5 percent.

MR. SMALL: The minimum of the two.

MR. QUINN: Maybe I've got them confused. And I'm sorry to slow you down. The minimum is 0.5 percent?

MR. FISCHER: The maximum is 0.5 percent. So it'll be no greater than 50 basis points.

MR. SMALL: The slide is intended to say the minimum of those two.

MR. QUINN: I'll let you carry on and I'll make sure I catch up later. Thanks.

MR. FISCHER: This may be a little bit clearer once we get to the second slide, slide 3, because we have the numerical derivation of these.

And the last time in terms -- is to calculate what the actual revenue adjustment would be in those two years, in 2019 and 2020. So the ROE premium dollar amount, which is effectively earnings, or a return, would need to be grossed up for tax, for income tax. So the ROE premium is then divided by 1 minus the tax rate to get that gross-up.

So then moving to slide 3 where we take these formulas and we apply some hypothetical numerics to it, so in A, step A, we're assuming that the actual ROE earned was 10.5 percent over the IR period, and the Board-approved allowed ROE was 10 percent. So we've got 50 basis points. We're multiplying times 50 percent and times 50 percent

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again, to get 0.125 percent, or 12 and a half basis points.

So that is in step B we're applying that now, to determine whether that is less or greater than 50 basis points. So 0.125 is less than 0.5, so 0.125 is the ROE premium. If it had been more than 0.5 -- it would have been 0.7 -- then the allowed ROE premium would have been 0.5.

Step C, we're actually calculating the dollar amount of earnings that falls out from that ROE premium. So we're assuming the rate base is $4 billion in 2019.

MS. GIRVAN: What's the 10.5 and the 10?

MR. FISCHER: Oh, that's just a hypothetical result. So 10.5 is what our actual ROE was on average over the five years of the IR term, and the 10 percent is the allowed ROE per the 2009 Board-approved formula, average over the five years.

MR. QUINN: To make sure I'm playing along at home here, you'd have to have a greater than 200 basis point difference between actual and approved ROE for your maximum 0.5 to kick in?

MR. FISCHER: Correct.

MR. QUINN: I think I hope got it. Thanks.

MR. FISCHER: So step C, so we know that 12 and a half percent -- or 0.125 percent, sorry, is the ROE premium. We're applying that to an assumed rate base of 4 billion in 2019. The equity ratio is 36 percent. The resulting ROE premium in dollar value is $1.8 million.

So $1.8 million of earnings, that's reflective of

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earnings, reward, would be applicable for 2019 and 2020. And as I suggested to Ms. Girvan is the last step is to convert that into a dollar value that would be applied to a just revenue requirement in 2019 and in 2020.

So the last step, then, is to take that $1.8 million and gross it up, 1 minus the tax rate -- we're assuming the tax rate is 26.5 percent in the illustration, and that grosses up to two-and-a-half million dollars.

So two-and-a-half million would be added to the revenue requirement each of those years, for a total of 5 million, in terms of revenue, and a total of 3.6 million, in terms of earnings.

MR. SCHUCH: Would there be any difference between a revenue treatment and just a regular deferral account disposition type of treatment? It's still the same dollars, I'm assuming. I'm not sure why you are boosting your revenue.

MR. SMALL: Let me just think about that for a second.

I don't think there would be a difference, because in order to record the amount in the deferral account we'd have to record a revenue stream offset it, which we would be taxed on, if that clarifies.

QUESTIONS BY MR. SHEPHERD:

MR. SHEPHERD: I have a couple questions. In order to calculate the raw incentive, you have to gross it up for taxes, but the net present value of the productivity initiatives is already dollar for dollar in rates, right? This is -- there's no tax adjustment to that, right?

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MR. FISCHER: I'm not following you. In terms of being in rates -- the next step, I think, is the NPV portion of it, so to the extent that we identify or put into effect new initiatives that result in -- in efficiency that, you know, extend beyond the IR term, so the NPV is done on that -- and how that's actually treated in the rates is unknown at this time, in a future period --

MR. SHEPHERD: Well, if your costs are lower, then your rate's going to be lower; right? If 2019 is your rebasing year.

MR. FISCHER: Right.

MR. SHEPHERD: So that's dollar for dollar, but the incentive is grossed up for taxes. I'm not sure I understand how that is a reasonable comparison. Can you help me with that?

MR. KANCHARLA: I'll try as well. What we're doing here is separating out the NPV of the productivity initiatives, and I think we'll get to the next slide where the net present value of the benefits, it's a criteria to prove that we are eligible for SEIM.

Here what Mr. Fischer has provided in this context, the treatment is like a formula-based ROE. Like, when we do in a cost of service the revenue-requirement calculations, we look at what is the allowed ROE, and then in terms of the calculation revenue requirement we gross it up for taxes.

So from a reward calculation perspective, actually, they're dealing from the NPV of the benefits to the reward calculation here.

Mr. Shepherd, when we walk through the benefits calculations, what is that we are doing and how is it linked to SEIM, it might provide more --

MR. SHEPHERD: Go ahead, and I'll come back to it.

MR. FISCHER: So in slide 5 now we're going into step two. So step one, we've calculated what the ROE premium is in terms of dollars. We've calculated what the revenue premium, in terms of dollars, is, based on the experience over the five years of the IR term. And so now we're diverging from the implementation of efficiency carryover mechanism in Alberta, so we've added on a number of tests, NPV of efficiency initiatives that have been pursued during the IR term. That's the next step, step two. And the final step is a check on various metrics.

So step two then is this NPV calculation, and essentially what needs to occur in terms of this test is the NPV of productivity initiatives identified in the productivity initiatives report, the NPV of those -- the life-cycle NPV of those initiatives needs to exceed the ROE premium, the total ROE premium, for those two years.

So in our example here it's $3.6 million. So we need to be able to demonstrate in the productivity initiatives report that on an NPV basis the total of all of those initiatives on a present-value basis exceeds that $3.6 million.

MR. SHEPHERD: Okay. So can I then follow up my question now?

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MR. FISCHER: Yes.

MR. SHEPHERD: Why are you comparing it to $3.6 million? You're asking -- the next present value of the benefits is 5 million. You are asking the ratepayers to pay another 5 million, right?

MR. FISCHER: I think it's valid, because the NPV calculation is after-tax calculation. It's a cash-flow analysis. So it's cash flow after tax, and the --

MR. SHEPHERD: There is no tax. It's expenses. So it's irrelevant.

MR. FISCHER: The NPV calculation is done after tax.

MR. SHEPHERD: No, no, sorry, this is not -- the -- when you have an expense, it flows directly through to rates. What the ratepayers save on that $5 million is a net present value of 5 million, and so I don't understand why, if you are asking them to pay an additional 5 million to you on the incentive, that you are saying, well, let's pretend they are only having to pay 3.6. I don't get that. I don't understand how it works.

MR. KANCHARLA: I think what we are trying to -- when we do the NPV calculations here, as Mr. Fischer related, this will be based on a cash-flow calculations here, right, so -- and the cash outflow, what we see it as the 3.6 million benefits, so in the example, maybe just to go back, when we discount the program's initiatives at the utility cost of capital and NPV comes zero, that means we -- the utility has earned as close to as allowed cost of capital or comparable allowed return equity.

So what we're saying now is to -- for the utility to get the benefits of the SEIM reward, we need to exceed the NPV equals to zero, right? And by what amount we need to exceed the NPV equals zero, and we're saying that that should be the reward that the utility is asking for.

MR. SHEPHERD: Maybe I've misunderstood the point of this test. I thought the point of this test was that the ratepayers couldn't be asked to give you a benefit that exceeded the benefit you were giving them. Isn't that the concept?

MR. KANCHARLA: That's right.

MR. FISCHER: So the benefit that we're --

MR. SHEPHERD: So the benefit you're giving them then is 5 million -- sorry?

MR. FISCHER: The benefit that the utility is getting is $3.6 million. That's the earnings benefit. The test is that -- is against that.

QUESTIONS BY MR. QUINN:

MR. QUINN: I think, Mr. Fischer, the question out of that would be, who pays the government, and in Jay's point the ratepayers are paying the government and you, but they're only getting the benefits if it exceeds the amount you get.

But my clarifying question, and I have flipped ahead to slide 5, is what you are saying, Mr. Kancharla, is that that table is based upon an after-tax NPV? Because that would clarify things.

MR. KANCHARLA: Yeah, the discount rate we would be

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using would be in an after-tax...

MR. QUINN: Okay. So that helps. And then I think we're getting closer to apple-apples (sic), but I see Mr. Shepherd isn't --

MR. SHEPHERD: No, I'm not, actually.

MR. QUINN: That's why I thought it was apples to apples. It's an after-tax --

MR. FISCHER: This is an ED calculation.

QUESTIONS BY MR. SHEPHERD:

MR. SHEPHERD: If this number here was 4 million, on the fifth slide, if that net present value was 4 million, then what the ratepayers get, in terms of rate savings on a net present value basis, is $4 million, but it costs them 5 million to get that, because they have to pay an additional 5 million to give you your incentive. Isn't that right?

MR. KANCHARLA: That's right, and I think actually Mr. Quinn --

MR. SHEPHERD: Okay. So I don't understand the logic.

MR. KANCHARLA: No, Mr. Quinn has actually helped me here. It's like, if you're looking at the cash flow, discount cash flow, it depends on which discount rate you are using, right? If you are using a pre-tax discount rate, then the comparable -- you are using a higher discount rate, and probably comparable would be 5 million here, but if you're using in an after-tax cost of capital here, we are comparing after-tax benefits here.

MR. SHEPHERD: Not even remotely. That's not -- they

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are not similar concepts. Here, if all the benefits were in 2019, there would be no present value, right? It would be immediate. Bam, right? And if that was 4 million, you'd say, By the way, please pay us 5 million, right? I don't understand that.

MR. CASS: Well, Jay, the problem I'm having is I don't think we're here to argue about it or to cross-examine. They have done their very best to explain it over and over. You are not accepting their explanation. I don't know what more we can do in this context.

MR. SHEPHERD: I'm trying to understand how -- the point that he's making. I'm not trying to argue with him. Mr. Kancharla has said that the use of weighted average cost of capital in the net present value makes a difference. If you use the example of all the benefits are in 2019, it's clear that that is not correct, so I'm giving you an opportunity to tell us what the correct answer is.

MR. FISCHER: In my mind, it's entirely consistent to use an after-tax earnings benefit and compare that to an after-tax NPV calculation. To me, that's apples and apples.

MR. SHEPHERD: Fine. Thanks.

MR. FISCHER: So the NPV calculation is step I, I guess, sub-step I under step 2, in terms of testing whether the SEIM award will be in fact awarded at the end of the IR term.

So I think we're on slide 6 now. So the next two steps under step three are looking at EGD's performance during the IR term with respect to metrics, and sub[illegible] is looking at customer relationship and operational performance metrics during the IR term.

So in this hypothetical example, there are -- well, this is not hypothetical. There are six metrics that make up customer relationship and operational performance. And so in this illustrative table here, we've -- what we're doing is we're comparing the average of the actual results during each year of the IR term to 2013. So we're taking an average for each metric and calculating that in the right column, and we're comparing that right column to the actual 23 -- 13 metrics for each one. And this test requires us to -- we must meet or exceed in terms of that average over the IR period for each metric, what that metric was in 2013.

So in this hypothetical example, if you go through it, the test is met. So each of these six metrics on average during the IR term, they meet or exceed the 2013 actual result for that metric.

QUESTIONS BY MR. WIGHTMAN:

MR. WIGHTMAN: James Wightman for VECC here. Can I ask a question? Was 2013 a pretty typical year in terms of those SQIs? I mean, to take one year. I'm just curious.

MR. KANCHARLA: I don't know particularly if 2013 is a unique year or one particular year, but what we're proposing is that, like any other rebase year, 2013 is a rebase year, and during the IR term we want to be better than the rebase year on the SQRs. That's how we come up

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with this, looking at 2013, yes.

MR. WIGHTMAN: I guess my point was if 2013 was a particularly not so good year in terms of SQIs, you would be setting the bar pretty low.

MR. FISCHER: I don't think Mr. Kancharla or myself know the answer to that. Clearly, 2013, we know what actuals are for that, and the IR period is each year after that, so... But whether it's typical or not, I don't know.

MR. QUINN: To satisfy Mr. Wightman, would you be able to provide the average from the previous IR terms, just as a comparative figure relative to the 2013 numbers?

MR. KANCHARLA: Yeah, we can take that undertaking.

MR. SCHUCH: This is an undertaking, and it would be TCU1.12.

UNDERTAKING NO. TCU1.12: EGDI TO PROVIDE AVERAGE FROM PREVIOUS IR TERM AS A COMPARATIVE FIGURE TO 2013 NUMBERS; TO PROVIDE SQR METRICS AND PERFORMANCE DURING THE IR PERIOD FOR THOSE SQR METRICS

MR. FISCHER: It's the first IR period? Through 2012 is what you're looking for? 2013 may not be available yet.

MR. QUINN: Yes, Mr. Fischer. I think Mr. Wightman was just saying one year, just a snapshot. You've got history that's previous to that. It's there as a comparator. You may -- some you may be higher, some you may be lower, but it should not be demonstratively atypical so that you've set the bar too low, in his words.

MR. FISCHER: Okay.

QUESTIONS BY MR. SHEPHERD:

MR. SHEPHERD: Can I ask a follow-up question? Could you undertake to apply this mechanism to the 2008 to 2012 period as if it were in place, and do all the calculations and tell us how much you would have been asking for -- had this been in place the last time around -- how much would you have been asking for in 2013 and 2014?

Now, you have to assume that criteria one had just been met, because you can't do that math because you don't have the productivity initiatives report, right? But assuming that has been met, can you go through the math and show us what that would have meant had it applied last time? Qualification under these tests, for example. How much would the premium have been and what would it have translated into, et cetera.

[Witness panel confers]

MR. FISCHER: Could I give you a qualified response? I think what you are saying is that not including any identification of specific productivity initiatives -- so we can definitely calculate -- this is the qualification in terms of the difference in ROE premium over the 1st Gen IR period.

The complication is with respect to the accounting error, and if and when we can get that factored into this or not.

MR. SHEPHERD: I'm told that you know what the bottom line impact on ROE is of the accounting error; you just don't know all the details yet, but you know what the final result is. I'm told that's true.

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MR. SMALL: Could you repeat that? That we know what the final impact is on ROE or --

MR. SHEPHERD: Yeah, the ROE, the new ROE number you know already. You've reported it to your board of directors, as I understand it. But what you don't have yet is the full breakdown of how that plays out to all the other numbers, but I don't think you need that for this calculation.

MR. SMALL: I guess subject to check. I'm not aware that we've calculated utility ROEs before and after earnings sharing, and normalized, un-normalized, at this point to account for each of the annual impacts of that accounting error. That's what I thought Andrew had indicated we would be looking to provide before the settlement conference.

MR. SHEPHERD: My understanding was that you've already done a report to your board of directors, in which you told them what the impact of this is.

MR. FISCHER: Can we leave it as if we can do it, we'll provide it? If it's there, we'll definitely do it.

MR. SCHUCH: That would be Undertaking TCU1.13. Thank you.

UNDERTAKING NO. TCU1.13: EGDI TO APPLY THE MECHANISM TO THE 2008 TO 2012 PERIOD AS IF IT WERE IN PLACE, AND HOW MUCH WOULD HAVE BEEN ASKED FOR IN 2013 AND 2014

MR. FISCHER: So I'm on slide 7, the last slide of our illustration.

And so the final test is relating again to metrics,

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and what we're comparing here is looking at SQR metrics, so again we're comparing actual SQR metrics resulting over the IR period and comparing that to 2013 actuals.

And this test is a little bit different than the first one in that what we're proposing is that we look at the overall average of all of these metrics and ascertain whether in terms of an overall average that we are in excess of, at or above in terms of the 2013 metrics greater than three years.

So in this illustration, we go through each one of the metrics, and we identify in the right-hand column each of the years during the IR term that we have met or exceeded the 2013 actual resulting metric. And we do that for each one of the metrics, so the first one is all five years, the second is all five years, all five years for the third and so on, and the fourth one in the illustration, only three years have met or exceeded. We do that for each one of them. We take the average of these one, two, three, four, five, six, seven metrics, and the resulting average is 4.625 in our illustration. So the test is, is that greater than three. And it is in this case.

So -- and that's the last test, so in our illustration we calculate the ROE premium, we calculate the ROE adjustment to revenue in 2019 and 2020, and then we apply these three tests, an NPV test around efficiency initiatives that extend beyond the IR term -- that's the first one, just to recap, and then the second and third relate to looking at performance metrics during the IR

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term. In the second case we're looking at specific customer and operational metrics. And then the final test is looking at SQR metrics.

And if we pass those three tests and those last three elements, these are the add-ons that I -- when I was talking earlier with Dr. Kaufmann was above and beyond what is implemented in the ECM mechanism that Alberta has adopted.

MR. QUINN: If I may -- sorry, Dr. Kaufmann, I just wanted to make sure, we said TCU-12 was the previous performance for step three criteria, which is maintain and improve their performance and customer relationship. Would you be willing just to add to that undertaking your SQR metrics and performance during the IR period for those SQR metrics also?

MR. FISCHER: So Mr. Quinn, if it's available, we will.

MR. QUINN: Okay. Thank you. And then just -- and then I promise not to get into argument here. The interaction you had with Mr. Shepherd helped me distinguish. I think what I heard -- and you can correct me if I'm wrong -- is your table in 1, calculating the NPV, these are not after-tax values in the table. The discounting factor you are using is based upon an after-tax value. Do I have that correct?

MR. KANCHARLA: That's correct, Quinn (sic). What we'll be doing is a cash-flow analysis here and use the appropriate discount rate. If we're using after-tax cash flows, we use an after-tax weighted average cost of capital. If you are using a pre-tax cash flow, we'll use a pre-tax WACC.

MR. QUINN: But the first point, these are pre-tax values in the table.

MR. KANCHARLA: Yes.

MR. QUINN: Thank you. That's all I need.

DR. KAUFMANN: I have a question. The SEIM is designed to create incentives for the companies to pursue efficiency gains in each year. And I'm just wondering if you can explain to me what about the mechanics that you just presented, where exactly do the incentives come in for the company to be consistent with respect to pursuing efficiency gains in every year, and more particularly in the last years of the plan? Where exactly do those incentives kick in? I just -- I'm -- when I think about the Australian plans, the ECMs and the Ofwat ICMs, it's very clear how that happens, but I'm just wondering, now you've gone through the illustration, if you can just show me exactly where in the dynamics there's some offsetting incentive for the company to say, Spend a little bit more in year five. Goldplate its capital stock, so that when it goes into the next five-year plan it can benefit from that, not just -- there's a short-term loss in that year, but there can be a five-year gain because that forms the basis for rate adjustments for the next IR plan.

So I'm just wondering, what about this mechanism offsets that incentives, which is -- offsets that

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incentive, which is what ECMs are designed to do?

[Witness panel confers]

MR. FISCHER: So I think I'm just going turn it over to Mr. Kancharla to answer part of your question, Dr. Kaufmann, and also, Ms. Frayer has additional comments, I think, to make to further answer that question. But I'll just turn it over to Mr. Kancharla at this point.

MR. KANCHARLA: Yes, what we're doing through our SEIM is really look at the AUC and establishing some criteria in terms of the calculations. It's just similar in terms of the reward. And for example, on slide 5 it is an illustration here, but if you look at the project or initiative C that we are looking at for, this is an initiative, if you look at its negative here, in 2018 this is a project that the utility might undertake in 2018. Clearly, if 2019 is a rebasing year. there is no benefit flowing. It is an incurred cost here.

Again, it's an illustration, but what we're showing here is, by investigating in a 3 million in a particular project or initiatives, we know that there are some sustainable benefits beyond the rebasing period. So that's what we are trying to capture through the SEIM incentive.

MS. FRAYER: To add to it from a conceptual perspective, if we didn't have the SEIM, there might hypothetically be incentive to take that $3 million investment and wait until 2020, after rebasing, because there would be no opportunity to count the net benefit of a dollar and recoup some of that.

So the presence -- I think the way I like to think about it, it's the presence of the SEIM, and the fact that the reward can only be attained in a future IR generation cycle and only if proven to be net beneficial to consumers. It's that overall concept that formulates the incentive for management not to delay investments that create long-term benefits.

DR. KAUFMANN: Have you done any analysis that looks at the potential trade-offs of a hypothetical scenario of a company deliberately waiting until the last year to spend capital and take a one-year hit in that year knowing that that capital stock will form the basis for the capital stock that's the basis for five years of rate increases past that point? Have you looked at those trade-offs and examined the trade-off of pursuing that potentially inefficient behaviour in the last five -- year five because of the long-term gain in the next plan? Have you looked at the trade-off of companies doing -- engaging in that type of behaviour and the extent to which the SEIM offsets that, that action in particular?

MS. FRAYER: We have not, and one thing I do want to note is the SEIM isn't meant to be just capital-driven investment. So I don't think we've specified here capital or OPECs. It's going to be a combination, and we don't want to predispose or pre-judge what kind of efficiency incentives there may be created.

I do understand your question, Dr. Kaufmann, as talking to the fact that from an accounting perspective opex and cap-ex may be treated differently, but the SEIM is not supposed to -- in, I think, potentially working a little bit off of the experience in the U.K., it's not supposed to provide any type of indicative preference for cap-ex or op-ex.

DR. KAUFMANN: Okay. In terms of the numbers that you have here for benefits -- so I assume these are potential saves in both op-ex and cap-ex. Is that correct? Going forward?

MR. KANCHARLA: Again, we're looking from a cash-flow analysis perspective, but it would include both -- whether it's capital benefits or cost or operating costs.

DR. KAUFMANN: Okay. So -- and just entirely cash flow, so $1 savings in cap-ex is treated the same as a $1 savings in op-ex, for this, for the basis of calculating benefits?

MR. KANCHARLA: That's right, and again, it's not -- as I said, this is just an illustration here, but, like, we would follow the typical cash-flow analysis, because there are some -- for example, for cap flow there are some CCA benefits available, so we would consider all the typical cash-flow analysis.

DR. KAUFMANN: But a $1 savings in capital has different implications for ratepayers than a $1 savings in operating expenditures, correct?

MR. KANCHARLA: From a cash-flow perspective it shouldn't be different.

DR. KAUFMANN: Well, but from an accounting -- from a rate-making perspective. If you save $1 in capital expenditures, that's going to have less of an impact on rates than a $1 saving in operating expenditures.

MR. KANCHARLA: That's correct, in a particular year. In one year, when you're looking at a one-year analysis, yes, it has a different impact.

QUESTIONS BY MS. GIRVAN:

MS. GIRVAN: I had a question. If we look at slide 5, if you could take, for example, take the line B, just so that I understand. So you are saying in B, in 2014 you are going to spend two-and-a-half million dollars on something, right? Something. But an example. Okay. So then in 2015 there's going to be a benefit of $500,000 in reduced costs; is that right?

MR. KANCHARLA: That's correct.

MS. GIRVAN: So that continues all the way through to 21. Now, in 2015 is that benefit reflected in earnings sharing?

MR. KANCHARLA: Yes, it will be.

MS. GIRVAN: Then the net present value of you spending that money over the course of the project is a million dollars?

MR. KANCHARLA: The net present value, again, it's an illustration here is -- what we're saying is over the life of the program, which is where we think the benefits would end is in '21, one million is the net benefits from the investment of 2.5 million.

MS. GIRVAN: Okay. And back to Dr. Kaufmann's

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question, the 2.5 million could be capital or O&M?

MR. KANCHARLA: That's correct.

MS. GIRVAN: Okay. Thanks.

QUESTIONS BY MR. BRETT:

MR. BRETT: I just have one question following up on that, on the last two questions. I apologize. I may have been out of the room when this came up, but looking at again at page 5, where do we see or where will we see a list of what might be called eligible sustainable savings initiatives, where and when? And when will we see, then, how you convert the -- how you calculate the proposed savings in each year from that -- from each of those types of initiatives? I'm just trying to put a little meat on the bones here. This is hypothetical, I understand, but I'm assuming that there's a sort of at least a going-in set of initiatives that you have in mind, areas that you propose to examine.

And my question is: When do we get a sense of what those areas are, and how exactly you calculate the financial benefits from each of those investments? And how do you decide over what period of years, for example, you should take into account those financial benefits from that particular investment? Because these will vary, presumably.

Is that going to take place at the end of each year, when you bring in your -- I've forgotten what you call it, but your efficiency initiatives report? Will that report document in sufficient detail how you arrive at these

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numbers and what the initiatives are?

In other words, a fairly -- where do we get a substantial description of what the initiative is all about? I'm not talking about the theory here; I'm talking about really what's going to happen on the ground. What kind of initiatives are we talking about, and how are those going to be valued on a unit basis and then on a total basis, given what you assess as being the reasonable scope of a program that would have a chance of achieving a certain amount of saving over a given period of years? When does all that come out?

MR. KANCHARLA: As we proposed in our applications, as part of the earnings sharing mechanism filing we will be providing a productivity initiatives report on an annual basis. So in that report would include the project details and the financial benefits, what those projects are yielding, so on an annual base as part of the SM application we will be filing this report.

MR. BRETT: I'm right, am I, in saying the intervenors would be able to challenge those numbers and those facts in each of those years? And that if you were -- the Board would have to pronounce on whether or not those particular set of initiatives and those costs were proper to include in this NPV calculation; is that correct?

MR. CASS: Tom, I'm not sure that we had thought it through to that point, that there would be annual review and challenge and decision by the Board. I think from the perspective of Enbridge, it was perceived to be annual reporting, but that the actual request for any sort of an application of this sustainable efficiency incentive mechanism doesn't happen until rebasing, and that would really be the time to get more into a testing and asking the Board for an actual decision.

I'm not sure what the Board would decide on an annual basis.

MR. BRETT: I take your -- first of all, I guess for people on the panel, is that your understanding as well? I take the point that you haven't thought through exactly how this mechanism would work and when these -- when these decisions would take place, but is it your understanding that there would really be no scrutiny of these costs and these measures, whether they were appropriate measures or whether they were --

The problem I have with that, incidentally, is you may get off on a track with a set of measures that really are felt by certain intervenors and perhaps by the Board to be inappropriate, or you may have a methodology for calculating the unit cost which is not -- does not stand up to sustained analysis.

I would think you would want to know and the Board would want to know early on if that were the case. Otherwise, at the end, we're waiting until the end of five years to look at this; we might have a -- it may be too late. We may have wasted effort on everybody's part.

This is a question, a rhetorical question. Do you see what I'm driving at? I'm asking the panel, actually.

MR. FISCHER: So I think my response, thankfully, would have been fairly consistent with what Mr. Cass offered. In terms of how we envision a review of what we're applying for, we don't see that happening until the end of the IR term. We will be reporting this on an annual basis, and subject to that scrutiny I think that speaks to the transparency that we're trying to achieve with this customized IR plan.

But in terms of us getting approval for the SEIM reward for the years 2019 and 2020,that won't happen until the end of the IR term. That's the way we saw it.

MR. BRETT: I'm not so much talking about approval for the reward at the end of the day, as I am for sort of some legitimation that these are appropriate measures or not, and whether the method that you've used to calculate the benefits is appropriate, but I'll leave it at that.

QUESTIONS BY MR. SHEPHERD:

MR. SHEPHERD: I have a couple of questions.

The first is I'm looking at this table on slide 5, and it doesn't look like -- it looks like you have not net-present-valued anything. And maybe I'm misunderstanding it, but the net present value is to the beginning of 2019, right? That would be how you would value it?

MR. KANCHARLA: That's correct, Mr. Shepherd. We would discount it to the year when we are seeking the reward.

MR. SHEPHERD: So that would be beginning of 2019, right?

MR. KANCHARLA: You're correct. I think what we illustrated here, so that the total NPV adds up, is one way to look at it. '17, '18, '19 are present value numbers here. It is a very simple illustration here.

MR. SHEPHERD: So the numbers up to '18 are actual costs or savings, and from '19 on, in this example, are NPV numbers?

MR. KANCHARLA: In this illustration, we kept it very simple. Each, '17, '18, if you add up all that, they will be come up total NP of 2 million. So these are not absolute dollars, just to keep the illustration simple.

MR. SHEPHERD: This may well be referred to in a hearing, so I want to make very sure I understand what the example is. It looks to me like the numbers in 2014 to 2018 -- where you're not doing net present value in those years, right?

MR. KANCHARLA: We would bring forward both the cost and the benefits to the year, then, when we're seeking the reward, which is in 2019.

So the time value of money of even 14 would be brought forward to 2019, and similarly the 23rd would be brought to the year then when we are seeking --

MR. SHEPHERD: So you would in effect be assuming that you get paid interest on your initial investment.

MR. KANCHARLA: Yeah, it's interest is a time value of calculation that we would be using here.

MR. SHEPHERD: All right. So then in this example, for example, you got in 2014 -- you've got an investment by

Enbridge of 2.5 million. You are actually assuming that that's 2 million, let's say, plus the time value of money to 2019.

MR. KANCHARLA: That's correct.

MR. SHEPHERD: And similarly, working the other way, backwards, you've got a number in 23 for A of 5 million as benefits, and you are assuming that that is actually, let's say, 4 million in benefit -- or, sorry, 6 million in benefits --

MR. KANCHARLA: It'll be higher. Higher.

MR. SHEPHERD: -- but discounted, it's actually 5 million.

MR. KANCHARLA: Yeah.

MR. SHEPHERD: Okay. Now I understand.

The second thing is, I'm trying to understand the interaction between this SEIM and the earnings sharing mechanism, and I just tried to do the math, because the earnings sharing mechanism operates on the same numbers, right?

MR. KANCHARLA: Yes.

MR. SHEPHERD: Okay. So, and am I right -- and you can undertake to provide this if you want -- that at approximately -- at anything -- at any number of average basis points above allowed ROE of 124.5 or less, the effect of your SEIM is to give back all of the earnings sharing or more; is that right? The threshold I calculated was 124.5. Does that sound about right to you? You can take that away as an undertaking if you want.

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MR. KANCHARLA: Yeah, because for the ESM you have a dead band as well, right, so --

MR. SHEPHERD: And that's why it's such a weird number, because you have to factor in the dead band. You can take it as an undertaking and do the calculations if you want.

MR. FISCHER: Mr. Shepherd, could you just restate the question so that we make sure we --

MR. SHEPHERD: Yes. As I understand what happens, it is, if your average ROE is 124.5 basis points above allowed ROE during the IRM term, then the effect of the SEIM is for the ratepayers to give back all or more than all of the earnings sharing that they received. It's just math.

MR. KANCHARLA: We'll take an undertaking.

MR. SCHUCH: That undertaking would be TCU1.14.

UNDERTAKING NO. TCU1.14: EGDI TO CALCULATE WHETHER, IF THE AVERAGE ROE IS 124.5 BASIS POINTS ABOVE ALLOWED ROE DURING THE IRM TERM, THEN THE EFFECT OF THE SEIM IS FOR THE RATEPAYERS TO GIVE BACK ALL OR MORE THAN ALL OF THE EARNINGS SHARING THAT THEY RECEIVED

MR. SCHUCH: Are there any further questions on the SEIM?

QUESTIONS BY DR. KAUFMANN:

DR. KAUFMANN: I just have one follow-up for Jay's question. And just in terms of the relationship between the SEIM and the ESM, as long as -- isn't it true that as long as the company is within the dead band for the ESM that -- but over its allowed rate of return, that customers

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EB-2012-0459
Exhibit K1.5

will be paying, because they won't get any benefits from the ESM because they are within the dead band, but there will still be a positive calculation of revenues to be earned from the SEIM, so isn't that correct?

MR. FISCHER: Yes, that's correct.

MR. SCHUCH: Any further questions of this panel on the topic of the SEIM that was handed out? No? Then the next party I have on my list on the agenda for this panel then is Schools.

QUESTIONS BY MR. SHEPHERD:

MR. SHEPHERD: Thanks. We're going to end at 4:00? Is that what you suggested in your e-mail? Okay. So what I suggest is, rather than start in on my written questions -- and by the way, are you going to answer any of the written questions in writing?

MR. LISTER: Yeah, I believe so. Our intent was that you would go through the questions, and where we would need to take an undertaking we would. Just thinking that maybe some of the exchange may have reduced your questions or may have created new questions for you. We're in your hands. If you have a better way to proceed, then --

MR. SHEPHERD: No, no, no. That's fine. I just wanted to know so I could prepare myself, but I have a number of questions on your updated A-2, tab 1, schedule 1, so why don't I start with that, and then you can -- that will take us 'til four o'clock, and we can proceed in the morning, if that's all right.

And these are not in our written questions. So I'm

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

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.

Context for Redesigned SEIM

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.

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

[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

> 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, <u>Distribution Performance Based Regulation</u>, 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.

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.

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.

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.

<u>Example 1:</u>

- *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.

<u>Example 2:</u>

- *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.

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

  - 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.

<u>IR PLAN PRODUCTIVITY</u>

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

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.

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.

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.

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.*

<u>Benchmarking</u>

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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EGDI to apply the SEIM mechanism to the 2008 to 2012 period as if it were in place, and to advise of the amount of any SEIM reward that would have been requested for 2013 and 2014.

RESPONSE

The calculation below illustrates the potential SEIM reward that the Company would have been able to request, had the SEIM mechanism been an approved component of the first generation IR plan.

	Actual Normalized ROE %	Board Approved ROE %	
2008	9.94%	8.66%	
2009	10.26%	8.31%	
2010	9.21%	8.37%	
2011	8.18%	7.94%	
2012	7.25%	7.52%	
Average	8.97%	8.16%	
Variance	0.81%		
	* 50%		
	* 50%		
Reward Potential	0.20%		or 0.5% (the lesser of the two)

ROE Premium ($) =	0.20% * $4,162.0M (2013 Approved Rate Base) * 36% (equity ratio) / 0.735 (reciprocal 26.5% tax rate)	
=	4.1	($million)
	* 2	2013 and 2014 reward payments
Total SEIM Reward =	8.2	($million)

The $8.2 million represents the potential amount that EGD would have been able to make an application for, provided that it could substantiate that the ratepayer benefits (i.e., sustainable efficiencies) were greater than this amount, and that EGD's

Witnesses: R. Fischer
S. Kancharla

performance metrics and service quality metrics had not declined since 2007. It should also be noted that use of the 2009 Board Approved ROE formula would have reduced the SEIM ROE potential (by reducing Board Approved ROEs for the 2010-2012 period) and will similarly reduce the potential going forward.

Witnesses: R. Fischer
S. Kancharla

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EGDI to calculate whether, if the average ROE is 124.5 basis points above allowed ROE during the IRM term, then the effect of the SEIM is for the ratepayers to give back all or more than all of the earnings sharing that they received.

RESPONSE

As stated at Exhibit A2, Tab 11, Schedule 3, the purpose of the SEIM is to include stronger incentives for the Company to implement long-term sustainable efficiencies which survive beyond the IR term and to encourage productivity investments in the later years of the IR term. These sustainable efficiencies will benefit ratepayers in terms of delivering safe and reliable energy to customers at rates lower than they would otherwise be beyond the IR term. ROE is only used as an input to calculate the potential SEIM reward. The SEIM reward will not be available to the Company unless it can meet the productivity and quality of service criteria as detailed on page 7 at Exhibit A2, Tab 11, Schedule 3.

As illustrated in the table below, the potential SEIM reward is calculated using the actual, after earnings sharing ROE. As a result, with an average overage of 124.5 bp (and including specific assumptions), the ESM amounts to ratepayers are approximately $1.2 million greater than the potential SEIM reward.

If this very specific example were to unfold, ratepayers would receive the benefit of $15.0 million in earnings sharing plus an amount greater than $13.8 million in base rates provided the SEIM reward can be justified with long-term, sustainable benefits and service quality and performance have not suffered during the IR term.

ESM Calculations

($ Millions)	2014	2015	2016	2017	2018	Total
Rate Base	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	
Equity 36%	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	
Allowed ROE	10.00%	10.00%	10.00%	10.00%	10.00%	
Actual ROE before sharing	11.245%	11.245%	11.245%	11.245%	11.245%	
Net overearnings after 100bp deadband	4.4	4.4	4.4	4.4	4.4	
Gross overearnings (tax rate 26.5%)	6.0	6.0	6.0	6.0	6.0	
ESM amounts returned to ratepayers	3.0	3.0	3.0	3.0	3.0	15.0
Actual ROE after sharing	11.122%	11.122%	11.122%	11.122%	11.122%	

SEIM Calculation

2014 - 2018 average actual ROE after sharing	11.122%	
2014 - 2018 average allowed ROE	10.000%	
Variance	1.122%	
ROE premium (Variance * 50% * 50%)	0.281%	(which is less than 0.5%)
2019 rate base	5,000.0	
2019 equity component of rate base	1,800.0	
Annual SEIM reward before gross-up for taxes	5.0	
Annual grossed-up SEIM reward	6.9	
Total SEIM reward (2 X Annual Reward)	13.8	

BOARD STAFF INTERROGATORY #29

INTERROGATORY

ISSUE A10 f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 19 of 24

LEI states that 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.

a) Please provide a complete list of all the ECMs proposed by gas or electricity distributors in Alberta
b) Please provide a complete list of all the ECMs approved for gas or electricity distributors in Alberta
c) Please compare in detail the differences between the ECMs proposed by Alberta utilities and those approved by the AUC
d) Please compare in detail the ECMs approved by AUC and Enbridge's SEIM.
e) Please compare in detail Australia's EBSS and Enbridge's SEIM.
f) Please compare in detail the efficiency carryover mechanisms approved in the UK and Enbridge's SEIM.

RESPONSE

a) See response provided on the following page:

Company	Proposed ECM schemes
ATCO Gas	ATCO Gas proposed an ROE ECM: "The ROE ECM would award ATCO Gas a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The ROE bonus would apply for 2 years after the end of the PBR Plan."[1] ATCO Gas originally proposed a K factor ECM as well, but withdrew it later in updated filing.[2]
ATCO Electric	ATCO Electric proposed an ROE ECM: "The ROE ECM would award ATCO Electric a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The ROE bonus would apply for 2 years after the end of the PBR Plan." [3] ATCO Electric also proposed a K factor ECM: "The K Factor Efficiency Incentive ("KFEI") amount will be calculated as the difference between the K Factor used to determine ATCO Electric revenues and the revenue requirement of the actual amount invested in the K Factor programs over the PBR term, providing that amount is positive. The KFEI amount that ATCO Electric will be allowed to retain after the PBR Plan ends will be equal to one half of the revenue requirement difference in the first year post PBR and one third of the revenue requirement difference in the second year post PBR."[4]

[1] ATCO Gas (2011) *ATCO Gas Performance Based Rate Application* (Rate Regulation Initiative Proceeding ID. 566), July 22, 2011, p. 44.
[2] ATCO Gas and ATCO Electric (2012) *ATCO Gas and ATCO Electric Performance Based Regulation Application - PBR Plan Finalization* (Rate Regulation Initiative, Proceeding ID. 566), February 22, 2012, p. 10.
[3] ATCO Electric (2011) *ATCO Electric Performance Based Rate Application* (Rate Regulation Initiative Proceeding ID. 566), July 22, 2011, pp. 11-1 – 11-2.
[4] Ibid.

EPCOR Distribution & Transmission Inc. ("EPCOR" or "EDTI")	EPCOR proposed an ROE ECM in "the form of a partial true-up of rates to a target rate of return at the end of the five-year PBR term."[5,6] In addition to promoting dynamic efficiency, EPCOR's proposed ECM mechanism also attempts to encourage compliance with service quality benchmarks: "In the case of the EDTI PBR plan, the ECM is directly linked to EDTI's provision of service quality over the course of the PBR regime. The provision of target level service quality results in EDTI being able, on a prospective basis, to (i) retain a share of any excess returns for a period of two years following the end of the PBR regime; or (ii) fully true-up rates to a target rate-of-return should there be deficient returns at the end of the PBR regime. Conversely, the provision of "inferior quality" results in EDTI (i) being forced to disgorge excess returns at the end of the PBR regime; or (ii) not being able to fully true-up rates to a target rate-of-return in the event of deficient returns at the end of the PBR regime."[7] "To summarize, the ECM is expressed formally by $\text{T-ROR}_{t+1} = \text{T-ROR}_t + (1 - \alpha) \times [\text{A-ROR}_t - \text{T-ROR}_t]$, where T-ROR is the target rate of return and A-ROR is the average rate of return as measured over the course of the PBR regime. The subscript "t" refers to the current PBR period, the subscript "t+1" refers to the subsequent PBR period and $0 \leq \alpha \leq 1$ is the rate-of-return adjustment parameter. "The ECM is designed to reward EDTI for, at a minimum, achieving target levels of service quality performance. EDTI proposes default values of $\alpha = ½$ when $\text{A-ROR}_t > \text{T-ROR}_t$ and $\alpha = 1$ when $\text{A-ROR}_t < \text{T-ROR}_t$. As such, when EDTI meets each of its four service quality benchmarks for each year of the PBR term, it is allowed to prospectively retain 50% of its excess returns (or be made whole should there be deficient returns) at the end of the PBR regime. "To provide strong incentives to comply with EDTI's service quality targets, α is adjusted by an increment of 0.025 for each service quality target that is not satisfied in any given PBR year. The adjustment in α is upward in the case of excess returns (i.e., the firm retains a smaller share of its excess returns) and downward in the case of deficient returns (i.e., the firm retains α larger share of its deficient returns). Given that there are four service quality measures and the term of the PBR plan is 5 years, there are a total of 20 annual service quality targets and the maximum adjustment in the value of $\alpha = 20 \times 0.025 = ½$."[8]

[5] EPCOR (2011) *EPCOR Distribution & Transmission Inc. 2013 – 2017 Performance Based Regulation Submission* (Rate Regulation Initiative Proceeding ID. 566), July 22, 2011, p. 3.
[6] "EPCOR, ATCO Gas and ATCO Electric proposed ECMs based on ROE as part of their PBR plans." Source: AUC Decision 2012-237 (September 12, 2012), p. 166.
[7] EPCOR (2012) *Final Argument of EPCOR Distribution & Transmission Inc.* (Rate Regulation Initiative Proceeding ID. 566, Exhibit 630.02), June 13, 2012, p. 100, paragraph 264.
[8] EPCOR (2012) *Final Argument of EPCOR Distribution & Transmission Inc.* (Rate Regulation Initiative Proceeding ID. 566, Exhibit 630.02), June 13, 2012, p. 102, paragraphs 272-274.

b) See response provided below.

Company	AUC-approved ECM schemes
ATCO Gas and ATCO Electric	AUC approved ATCO Gas's and ATCO Electric's proposed ROE ECM. In its Decision, the Commissions stated that "[it] 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 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."[9]
EPCOR	AUC also approved EPCOR's proposed ECM but with adjustments: "EPCOR's proposed ECM includes adjustments for both over- and under-earnings in the two years following the end of the PBR term. The UCA (Utilities Consumer Advocate) did not support EPCOR's ECM because it compensates for under-earning which would dampen incentives and shield the utility from the full impact of its decisions. The Commission agreed. As discussed above, the Commission also supported a 0.5 per cent limit to the amount of earnings which may be carried over. Accordingly, the Commission found that EPCOR's ECM should not include an adjustment for under-earning and should limit the amount of earnings which can be carried over to a maximum of 0.5 per cent.[10] The Commission also rejected, EPCOR's proposed service quality adjustments to its ECM formula.[11]

[9] AUC Decision 2012-237 (September 12, 2012), p. 169.
[10] AUC Decision 2012-237 (September 12, 2012), p. 169.
[11] Ibid.

c) See response provided below:

Company	Proposed ECM schemes
ATCO Gas	As is detailed in LEI's responses to I.A10.EGDI.STAFF.29 (a) and (b), AUC approved ATCO Gas's ROE ECM in the form as it was proposed.
ATCO Electric	As is detailed in LEI's responses to I.A10.EGDI.STAFF.29 (a) and (b), AUC approved ATCO Electric's ROE ECM in the form as it was proposed, while the proposed K factor ECM was denied.
EPCOR	As is detailed in LEI's responses to I.A10.EGDI.STAFF.29 (a) and (b), AUC denied in part EPCOR's proposed ECM, and instead approved the ECM scheme that was similar to that approved for ATCO Gas and ATCO Electric.

d) Enbridge's newly revised SEIM is similar in some respects to the ECM that was approved by AUC for ATCO Electric, ATCO Gas and EPCOR, namely in the estimate of the award amount and its basis related to actual ROE. However, LEI believes that the revised SEIM has better incentive properties for long term sustainable productivity growth, as it requires that EGD document and show that it has indeed brought about initiatives that would improve productivity over the long run. Please refer to EGDI's updated SEIM filed at Exhibit A2, Tab 11, Schedule 3.

e) Australia's efficiency benefit sharing scheme ("EBSS") has been in place for distribution network service providers ("NSP") since June 2008 and for transmitters since September 2007.[12] Australia's EBSS applies only to opex,[13] and not to capex.[14] EBSS rewards outperformance in opex savings and penalizes overspends in opex (as measured by the difference between forecast opex in the building blocks stage with actual opex). The EBSS is measured on a five-year rolling basis, and employs a real discount rate of 6%. Under the EBSS, NSPs can retain approximately 30% of the opex underspend, while the remaining 70% return to ratepayers through lower rates in the next regulatory term; and, symmetrically, NSPs bear approximately 30%

[12] AER (June 2008) *Electricity distribution network service providers - Efficiency benefit sharing scheme*, Final Decision, June 2008; AER (September 2007) *Electricity transmission network service providers efficiency benefit sharing scheme*, Final Decision, September 2007.
[13] AER (June 2008) *Electricity distribution network service providers - Efficiency benefit sharing scheme*, Final Decision, June 2008, p. 11.
[14] Currently, Australian NSPs use a capital expenditure sharing scheme ("CESS"): "For capex, the sharing of underspends/overspends currently occurs by updating the regulatory asset base (RAB) for actual capex at the end of each regulatory control period. If a NSP has underspent, it will benefit during the regulatory control period. Consumers will benefit at the end of the period when the RAB is rolled forward at a lower level than if the full amount of the capex allowance had been spent." Source: AER (March 2013) *Better Regulation, Expenditure incentives guidelines for electricity network service providers*, Issues Paper, March 2013, p. v.

of the opex overspend, and the remaining are passed through to ratepayers in the form of higher rates in the next regulatory period.[15] EBSS does not apply to uncontrollable opex, as well as operating costs related to non-network alternatives, pass-through events, and changes in capitalisation policy impacting forecast opex.[16]

In 2012, Australian Energy Regulator ("AER") initiated Better Regulation consultation to "set out our [AER's] approach to regulation under the new rules. They will cover how we [AER] assess expenditure proposals, calculate the allowed return on assets, allocate costs, engage with consumers, and more."[17] Better Regulation Final Guidelines have been published on November 29, 2013. AER has outlined new forecasting methodology for opex, and therefore the new adjusted opex EBSS because "EBSS is intrinsically linked to the forecasting approach for opex."[18] The new opex EBSS will operate as follows:

- "The regulatory regime provides for ex ante opex forecasts. The NSP keeps the benefit (or incurs the cost) of delivering actual opex lower (higher) than forecast opex in each year of a regulatory control period.
- The EBSS carries forward a NSP's incremental efficiency gains for the length of the carryover period. This carryover period length will typically be five years for a five year regulatory control period.
- The carryover amounts accrued in year i of period n + 1 will be the summation of the incremental efficiency gains in period n that are carried forward into year i.
- We [AER] add the carryover amounts as an additional 'building block' when setting the NSP's regulated revenue for the period n + 1.

[15] AER (March 2013) *Better Regulation, Expenditure incentives guidelines for electricity network service providers*, Issues Paper, March 2013, pp. vi – vii and 24-25.
[16] AER (June 2008) *Electricity distribution network service providers - Efficiency benefit sharing scheme*, Final Decision, June 2008, p. 45.
[17] See http://www.aer.gov.au/Better-regulation-reform-program for more information
[18] The new opex forecasting method is called "revealed cost base-step-trend" forecasting approach: "When forecasting opex we [AER] typically use one year of actual opex to forecast future opex (typically the penultimate year of the current regulatory control period). We [AER] then make changes for factors such as output growth, real price changes, productivity growth and any other efficient cost changes." Source: AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 6. For more information on Better Regulation's new expenditure forecasting and incentive guidelines, see http://www.aer.gov.au/Better-regulation-reform-program.

- The actual opex incurred in the base year is used as the starting point for forecasting opex for period n + 1.

- Under this approach, the benefits of any increase or decrease in opex is shared approximately 30:70 between NSPs and consumers."[19]

According to the November 2013 "Better Regulation: Explanatory Statement – Efficiency Benefit Sharing Scheme for Electricity Network Service Providers," the EBSS has stayed largely the same, with the following changes:

1) AER has merged EBSS for DNSPs and TNSPs into a single EBSS, which will have no impact on operation of the EBSS;[20]

2) AER has clarified how carryover period will be determined, which will also not affect operation of EBSS;[21] and

3) The only changes to the operation of the opex EBSS are changes "to the allowed adjustments and exclusions, and accounting for adjustments for one-off factors in the base year when forecasting opex."[22] AER determined that there will be no longer exclusions of 'uncontrollable' opex costs,[23] that exclusions of opex from EBSS ex post will now be "limited to those categories of opex not forecast using a single year revealed cost approach in the following period,"[24] and AER has "amended the EBSS to account for any adjustments made to base opex to remove the impacts of one-off factors."[25]

EGD has revised its proposed SEIM. Please refer to the updated Exhibit A2, Tab 11, Schedule 3.

f) In the UK, Ofgem "undertake[s] an ex post review of GDNs [gas distribution networks] **output performance** in relation to asset health/risk, asset load/capacity utilisation secondary deliverables, as well as safety risk primary output at the end of RIIO-GD1" and uses a carry-over mechanism that is set out to "carry-over any

[19] AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, pp. 6-7.
[20] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 8.
[21] Ibid.
[22] Ibid, pp. 7-8.
[23] Ibid, pp. 16-17.
[24] Ibid, p. 25.
[25] Ibid, p. 20.

under- or over-delivery of outputs at the next review, with the GDN incurring the cost (or benefit) of the under (over) delivery."[26]

Ofgem elaborated: "As with the other ex post reviews of outputs, our review of GDNs' performance in relation to NOMs [network output measures] will not consider GDNs' cost efficiency; our assessment will focus only on output performance. In general, we propose to take the NOMs secondary deliverable target for the end of RIIO-GD1 as the opening position in determining funding levels to meet RIIO-GD2 NOMs target. Any under-delivery or over-delivery against the NOMs target during RIIO-GD1 would either require catch-up or be carried forward in order to meet its RIIO-GD2 NOMs target. In relation to the reward, we have decided to apply a reward of 2.5 per cent of additional costs associated with a material over-delivery if the GDNs are able to robustly justify that the over-delivery is in the consumer interest. Similarly, we will apply a penalty of 2.5 per cent of the avoided costs associated with a material under-delivery if the GDN is unable to robustly justify that the under-delivery is in the consumer interest. Where there is substantial unjustified under-delivery we may consider whether it is appropriate also to use our powers relating to enforcement of licence conditions."[27]

In addition, Ofgem uses a rolling incentive mechanism to enhance incentives for achieving reduction targets of gas shrinkage (i.e., gas lost during transportation) "to ensure that companies retain the benefits of outperformance (or costs of underperformance) for eight years irrespective of when in the price control period the outperformance or underperformance is realized,"[28] and "a true-up in RIIO-GD2 [the next regulatory period] then adjusts these revenues to take account of any performance which proved not to be enduring."[29] Ofgem explained that "the proposed rolling incentive mechanism will enhance GDNs' prospective rewards and penalties for their performance in minimising shrinkage volumes without exposing them to increased commodity price risk (which they recover through allowed revenues). Companies will receive a forecast allowance for shrinkage based on allowed shrinkage volumes … and a forecast gas price. These forecast costs will then be adjusted to take account of actual gas costs."[30]

EGD has revised its proposed SEIM. Please refer to the updated evidence at Exhibit A2, Tab 3, Schedule 11.

[26] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p.67.
[27] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, pp. 68-69.
[28] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p. 15.
[29] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p. 16.
[30] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p. 17.

BOARD STAFF INTERROGATORY #30

INTERROGATORY

ISSUE A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 19 of 24

LEI writes that "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 vary in the detail, they all 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 that are finite, utility operations operate over longer and more dynamic timeframes."

a) Please explain how the SEIM overcomes "the limitations imposed by allowing a utility to benefit from efficiencies achieved only during the term of the IR plan."

b) Please provide a numerical example which shows how the SEIM encourages Enbridge to retain the benefits of an initiative designed to improve its efficiency that it would otherwise not pursue because the Company would only be allowed to retain the benefits of those efficiency gains within the term of its IR plan.

c) LEI says that one of the common features of the mechanisms it references is "ex post awarding of the benefits;" would the SEIM reward Enbridge ex post (i.e. after the initiatives have been implemented) or ex ante (before the initiatives have been implemented)? Please explain.

d) LEI says that one of the common features of the mechanisms it references that "they all recognize that unlike rate periods which are finite, utility operations operate over longer and more dynamic timeframes." Please explain how the SEIM satisfies this criterion.

RESPONSE

a) It is recognized that incentives to reduce costs differ over the duration of the regulatory period. Generally, utilities achieve cost savings or reduce costs during the first few years of the regulatory period because that would yield a greater return than cost reductions achieved during the last year of the regulatory period that may be kept for only one year. An Efficiency carryover mechanism ("ECM") can be adopted to address this concern. With ECM, later-year efficiency gains could be preserved in the subsequent regulatory period. EGDI's updated SEIM is similar to an ECM in that it creates incentives in such a way that they relate directly to long-term, sustainable efficiencies or benefits. Please refer to Exhibit A2, Tab 11, Schedule 3 for information on the updated SEIM.

b) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

c) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

d) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

BOARD STAFF INTERROGATORY #31

INTERROGATORY

ISSUE: A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 20 of 24

"LEI finds that Enbridge's proposed (SEIM) mechanism is consistent with the overarching principles applied in other jurisdictions for allowing 'roll over' mechanisms for efficiency savings.'

a) Please describe the "overarching principles" in the jurisdictions referenced by LEI.

b) Please explain whether any of the mechanisms in these jurisdictions award a utility upfront because of efficiency gains it has forecast?

c) Please explain whether awarding a utility based on forecast efficiency savings is consistent with a "roll over" of efficiency savings into the term of a subsequent incentive regulation plan?

RESPONSE

a) The "overarching principles" of an efficiency carryover mechanism conceptually and generically is to address the incentive issue of companies implementing less cost savings in later years of an IR term because the expected returns will be too short-lived given the term of the IR. In other words, an ECM would overcome the motivation to hold off making efficiency improvements until after rates are re-set and that will mean overall more efficiency endeavors on a more constant basis, regardless of when the IR term expires. This then provides benefits to consumers in the long run.

   However, in the specific jurisdictions of Australia and UK, the conceptual principles have been verbalized and clarified and we excerpt some of the specific regulations below as further reference for the Board.

In Australia, "Clauses 6.5.8 and 6A.6.5 of the NER [National Energy Rules] outline the requirements for an EBSS. In developing and implementing any EBSS the AER must have regard to:

1) the need to provide NSPs with a continuous incentive to reduce opex

2) the desirability of both rewarding NSPs for efficiency gains and penalising NSPs for efficiency losses

3) any incentives that NSPs may have to capitalise expenditure; and

4) the possible effects of the scheme on incentives for the implementation of non-network alternatives.

In addition, for DNSPs [distribution network service providers], the AER must ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs.[1]

AER employs EBSS to address the following incentive issues:

1. A NSP has an incentive to increase opex in the expected 'base year' to increase its forecast opex allowance for the following regulatory control period.

2. A NSP's incentive to make sustainable change to its practices, and reduce its recurrent opex, declines as the regulatory control period progresses. It then increases again after the base year used to forecast opex for the following regulatory control period. By deferring these ongoing efficiency gains until after the base year the NSP can retain the benefits of doing so for longer because they won't be reflected in the opex forecasts for the following period.[2]

The Australian EBSS (both used by NSPs currently and per new November 2013 Better Regulation Final Guidelines) "aims to provide a continuous incentive for NSPs to pursue efficiency improvements in opex,"[3] and ensures "a fair sharing between NSPs and network users of efficiency gains and losses made during a regulatory control period"[4] via a symmetric scheme on gains and losses that provides "the same

[1] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 15.
[2] AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 6.
[3] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 6.
[4] AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 5.

reward for an underspend and the same penalty for an overspend in each year of the regulatory control period."[5]

The UK carry-over mechanism enhances current RIIO incentives by incentivizing "the delivery of outputs by means of an ex-post review of outputs with carry forward or catch-up of the incremental output over-delivery or shortfall in the next period."[6]

In addition, the rolling incentive mechanism for shrinkage and leakage ensures that "companies retain the benefits of outperformance (or costs of underperformance) for eight years irrespective of when in the price control period the outperformance or underperformance is realized."[7]

b) Please see the response to Board Staff Interrogatory #33(a) found at Exhibit I.A10.EGDI.STAFF.33.

c) There are similarities with regards to awarding a utility based on forecast efficiency savings and a "roll over" of efficiency savings into the term of a subsequent incentive regulation plan. Under a roll over efficiency mechanism, any efficiency gains are retained by the utility for a set period of time before being allocated to consumers. This allocation can be a one-off price reduction or phased in over time. Similarly, when awarding a utility based on forecast efficiency savings, the utility retains the efficiency gains for a set period of time (or during the regulatory period), and only after the requisite timeframe runs out will these efficiency gains be allocated to consumers.

   EGD has updated its SEIM plan where it has committed to request an ECM award (SEIM award) only if EGD is successful at demonstrating to the Board that the forecast efficiency savings are sufficiently greater than the award payout. It should also be noted that OEB will still have to review EGD's efficiency gains or savings before allowing EGD's award under SEIM.

[5] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 10.
[6] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p.72.
[7] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p.15.

BOARD STAFF INTERROGATORY #32

INTERROGATORY

ISSUE: A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 21 of 24

"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."

a) Please explain in detail how the SEIM would encourage "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."

b) Please provide a numerical example which demonstrates how an incentive payment in year 1 of Enbridge's proposed Customized IR plan would encourage Enbridge to undertake an initiative in year 4 of that plan that it would not have undertaken in the absence of the incentive payment in year 1.

c) In the example provided in part b), please explain whether the incentive payment provided in advance in year 1 would reduce Enbridge's incentive to follow through in year 4 on the efficiency-improving initiative in question.

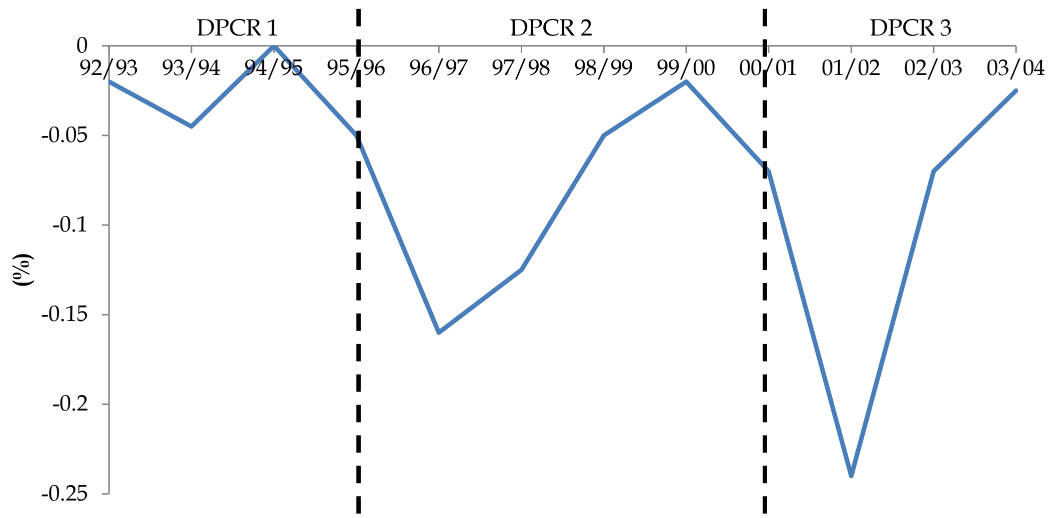
RESPONSE

a) Generally, utilities act differently when the strength of regulatory incentives changes within and between regulatory periods. For instance, in the UK before the 5th Distribution Price Control Review ("DPCR5"), the level of cost reductions achieved in the year following the price review was significantly higher than other years, and costs reductions gradually trail off until the next price review (see Figure 1 below). This can be explained by the declining reward for efficiency over the regulatory period under the IRM framework used in the UK, and specifically because the later years would be referred to and used as the base year to reset prices for the next regulatory period. For DPCR5, the UK regulator (Ofgem) strengthened the IRM with the rolling mechanism incentive to ensure stable incentives for efficiency throughout the regulatory period.

Similarly, incorporating EGDI's proposed SEIM in the IRM plan would provide for time-consistent incentive to EGDI. By maintaining consistent incentives throughout the regulatory period, EGDI's investment decisions are not distorted. The absence of SEIM will skew cost reduction initiatives to the early years of the price control and results in declining of cost reduction incentives at the end of the price control period.

EGDI revised its proposed SEIM. Please refer to Exhibit A2, Tab 11, Schedule 3.

Figure 1. Growth in Real Unit Operating Expenditure (UK Electric Distribution)



Source: Crew, Michael and Parker, David. International Handbook on Economic Regulation (Figure 8.3)

b) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

c) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

BOARD STAFF INTERROGATORY #33

INTERROGATORY

ISSUE A10f.: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Exhibit: I.A10f.EGDI.Staff.33

Evidence Ref: Exhibit A2, Tab 10, Schedule 1, Page 21 of 24

LEI states that the key difference in Enbridge's proposal from the schemes outlined by LEI [Alberta, UK and Australia] is that Enbridge's SEIM is based on estimated rather than actual benefits.

a) Please provide references in jurisdictional precedent where the utility's financial gains under an efficiency carryover mechanism are based on estimated benefits rather than achieved / actual benefits.

b) In the examples mentioned in part a) where efficiency carryovers are based on estimated benefits, is there a true-up mechanism when the actual benefits become known (i.e., is there is a true-up in the utility's financial gain when actual /achieved benefits are less than estimated benefits)? If so, please explain these true-up mechanisms in detail.

RESPONSE

a) We are not aware of any jurisdictional precedent where the utility's financial gains under an ECM are based on estimated benefits rather than actual benefits, but that does not preclude the fact that there are other examples where financial remuneration in regulatory—proved utility programs are based on forecasted benefits and forecasted measures of impact – such as energy efficiency programs.

b) See answer on (a) above.

SEC INTERROGATORY #45

INTERROGATORY

Issue A10: 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
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/4/1] Please provide examples of circumstances in which the change from "unexpected events" to "unexpected costs" would result in a change from non-recovery to recovery from ratepayers.

RESPONSE

The Company is not proposing a change from "unexpected events" to "unexpected costs".

It is proposing that one of the Z-Factor criteria be "The cost increase or decrease, or significant portion of it, must be demonstrably linked to an unexpected, non-routine cause." This is in contrast to the current criteria which, as described in Exhibit A2, Tab 4, Schedule 1, page 4, require the identification of a discrete event.

Since Z-Factors are used for unexpected events, it is challenging to envision the unexpected, however, the following illustrates the difference between an "event" and "cause" could be perceived.

Consider the unexpected catastrophic failure of a component of the distribution system. Assume there had been no previous suspicions or cause for concern regarding this component, however, as a result of the failure and an imminent risk to public safety the

Company deemed it prudent to begin a replacement program for 15,000 units across the system. It cost $10,000 to replace each component.

In this case the “event” could be considered the single component failure, which would have failed the threshold test of $1.5 million impact on revenue requirement and consequently would not qualify as a Z-Factor. Alternatively though, the component failure could be seen as the “cause” of a $150 million cost, which would qualify as long as it was found to be prudently incurred.

CCC INTERROGATORY #21

INTERROGATORY

Issue B17 – Is the Allowed Revenue amount for each of 2014, 2015 and 2016 appropriate including:

Operating Costs

(Ex. A2/T1/S3/p. 8) For each year 2014-2016 EGD has established Operating Cost budgets. The evidence indicates that productivity savings are embedded in each of those budgets. Please provide the forecasts of O&M in each of those years excluding the productivity savings.

RESPONSE

Please refer to the following table for the forecasts of O&M in each of those years excluding the savings.

		Col. 1	Col. 2	Col. 3
Line No.	Categories ($ Millions)	Budget 2014	Budget 2015	Budget 2016
1.	Customer Care/CIS Service Charges	$92.6	$96.5	$100.4
2.	Demand Side Management ("DSM")	32.2	32.8	33.5
3.	Pension and OPEB Costs	37.2	33.8	30.9
4.	Regulatory Cost Allocation Methodology("RCAM")	35.3	34.0	33.8
5.	Other O&M (Excluding Productivity Savings)	252.1	261.6	276.6
6.	Total Net Utility O&M Expense	$449.4	$458.6	$475.1

The budget process did not isolate amounts from prioritization pacing and productivity for identifying the O&M savings. The savings for each year included within Line 5 are:

2014: $24.1 million
2015: $30.1 million
2016: $35.6 million

Details of these savings are set out in the response to Board Staff Interrogatory #19 found at Exhibit I.A2.EGDI.STAFF.19.

Witnesses: R. Fischer
S. Kancharla
M. Lister

BOARD STAFF INTERROGATORY #19

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: A2/T1/S2/P 6 of 15

Enbridge says that "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 horizons, 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."

a) Please document and quantify all the "known or highly probable cost increases over the forecast horizons" which Enbridge did not include in its projected OM&A budgets over the 2014-2016 period.

b) Please document and quantify all the costs which Enbridge is holding flat, "which in reality will not be flat," in its projected OM&A budgets over the 2014-2016 period.

RESPONSE

a) Please see the following table for the quantification of all the known or highly probable cost increases not included within O&M budgets over the forecast horizons. Explanation of the items that are quantified below is set out within the D1 series of Exhibits.

Line No.	Particulars ($ millions)	2014	2015	2016
1).	Merit increase	$1.2	$2.0	$2.5
2).	Employee benefits	2.1	2.2	2.3
3).	Incremental cost to service new customers	1.5	1.6	1.7
4).	Incremental safety and integrity work	8.9	9.1	9.3
5).	External contractor rate increases	0.3	1.4	1.7
6).	Increased volume of locates - compliance with Bill 8	2.6	3.2	3.8
	Highly probable cost increases	$16.5	$19.4	$21.3

Witnesses: R. Fischer
S. Kancharla
M. Lister

1) Merit increase assumed 2.2% in the O&M budget but in reality the merit increase is expected to be around 3.0%.

2) Employee benefits costs are expected to increase 6.1% annually in 2014 and onwards as opposed to 2.2% assumed in the budget.

3) The service work associated with adding new customers is not embedded in the O&M budget. By excluding the incremental costs relating to customer care outsourcing charges which is covered under the CC/CIS service charges, the net impact is $1.5 to $1.7 million each year.

4) The Company has experienced significant requirements for safety and integrity work which has caused the cost to increase more than the inflation rate. The Company has made tremendous efforts to prioritize activities to alleviate the cost pressures.

5) External contractors for Operations are expected to increase their rates between 3% and 6% during the IR term. As a result, the cost increase is more than the inflation rate

6) The Company has experienced a substantial increase for locates requests since the new legislation Bill 8 took effect. Therefore the volume of locates are anticipated to go up at a rate of 6% per annum.

b) Please refer to the following table for the quantification of all the costs which Enbridge is holding flat, "which in reality will not be flat".

Line No.	Particulars ($ millions)	2014	2015	2016
1).	FTE's	$2.8	$5.7	$8.7
2).	Bad debt expenses	4.7	5.0	5.6
	Total	$7.5	$10.7	$14.3

1) The budget assumes that the Company keeps FTEs flat in the IR term. If FTEs increase 2% (or 47 FTEs) each year assuming 25% O&M and 75% capital, the salary, benefits and other labour related costs would go up significantly for both O&M and capital. The table above indicates the dollar impact for the O&M only.

Witnesses: R. Fischer
S. Kancharla
M. Lister

2) Bad debt expense is forecast to stay flat, but in reality bad debt expense would be expected to increase significantly based on external factors such as gas prices, weather, and economy.

Witnesses: R. Fischer
S. Kancharla
M. Lister

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.

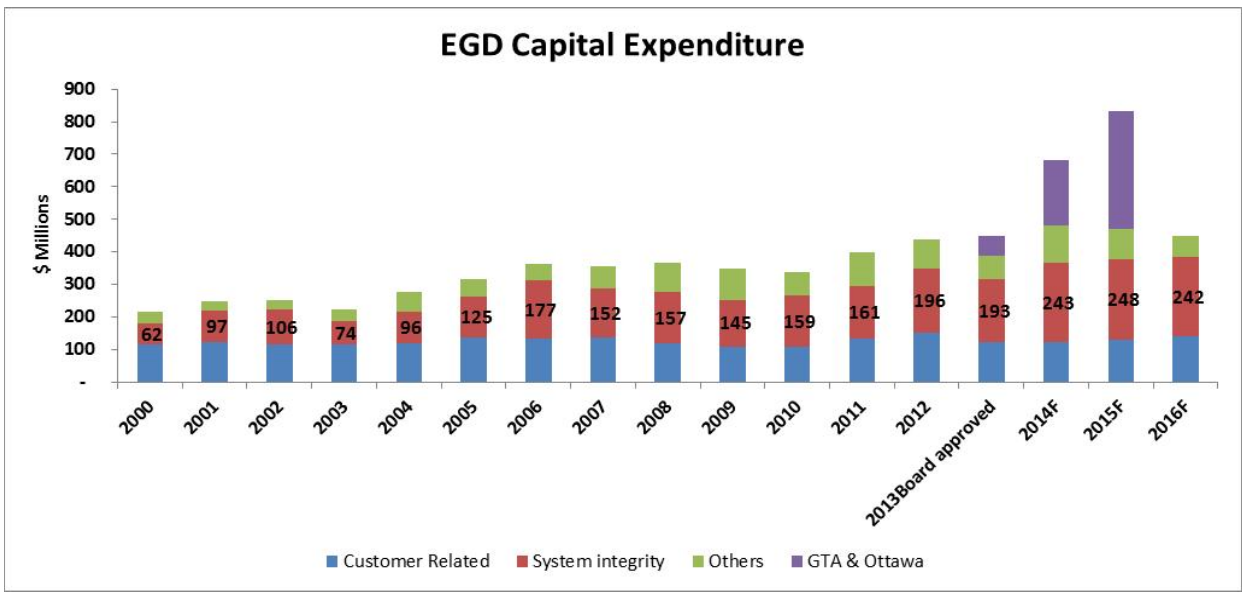
2. Specifically, this evidence will present:
   a) EGD System Challenges
   b) Traditional Model for Cost Recovery
   c) Limitations of I-X Frameworks
   d) Challenge of an I-X model in EGD's circumstances
   e) Challenge of Increasing Depreciation and Amortization Expense
   f) Other Considerations 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.

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.



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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.

<u>Challenge of an I-X model in EGD's circumstances</u>

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 SRC impact. /u
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

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

	Rebase	Second Generation IR			
Revenue - IR ($M)	**2013**	**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%**

Analysis and Interpretation of Scenario 2

Sc2: Scenario 1 plus new Y factors for the GTA and Ottawa reinforcement projects

	Rebase	Second Generation IR			
Revenue Requirement - IR ($M)	**2013**	**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.

Analysis and interpretation of Scenario 3

Sc3: Breakeven escalation factor such that ROEs in Scenario 2 from I-X and allowed ROE are equal

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 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 SRC impact

Allowed Revenues - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr- CAGR
	ADR				
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	***2.5%***
Productivity		0.0%	0.0%	0.0%	
I-X		2.5%	2.5%	2.5%	
Customer growth		1.7%	1.7%	1.7%	***1.7%***
Total Escalation factor		4.2%	4.2%	4.2%	***4.2%***
2013 Revenue Requirement	**817**				
Allowed Revenues - IR with escalation		**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	62	
SRC impact	-	(61)	(55)	(48)	
	1,021	148	163	223	
Total Allowed Revenues -IR	**1,021**	**999**	**1,050**	**1,148**	***4.0%***
Achieved ROE	**8.9%**	**8.7%**	**9.4%**	**9.3%**	***9.1%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Achieved vs Allowed)		**-0.6%**	**-0.4%**	**-0.9%**	**-0.6%**

/u

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 4.0% was calculated. The forecast average annual ROE over the IR term under an /u I-X model is 0.6% less than allowed ROE. /u

Analysis and Interpretation of Scenario 5

Sc5: Breakeven escalation factor such thatannual average ROEs in Scenario 4 are equal to forecast allowed ROE

Allowed Revenues - IR ($M)	**Rebase 2013**	**Second Generation IR 2014**	**2015**	**2016**	***3 yr- CAGR***
	ADR				
Escalation factor					
Escalation factor (Inflation)		4.0%	2.0%	4.0%	***3.3%***
Productivity		0.0%	0.0%	0.0%	
I-X		4.0%	2.0%	4.0%	
Customer growth		1.7%	1.7%	1.7%	***1.7%***
Total Escalation factor		5.8%	3.7%	5.8%	***5.1%***
2013 Revenue Requirement	**817**				
Allowed Revenues - IR with escalation		**864**	**896**	**948**	***5.1%***
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	
SRC impact	-	(61)	(55)	(48)	
	1,021	148	162	223	
Total Allowed Revenues -IR	**1,021**	**1,012**	**1,058**	**1,171**	***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 (Achieved vs Allowed)		**0.0%**	**0.0%**	**0.0%**	**0.0%**

/u

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 3.3%. This required escalation factor is significantly greater than the forecast inflation and productivity factor of 2.5% recommended and forecast by Concentric. /u

Analysis and Interpretation of Scenario 6

Sc6: Same assumptions as Scenario 4 except I-X is assumed equal to the actual effective I-X during 1st Generation IR term

/u

Allowed Revenues - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr- CAGR
	ADR				
Escalation factor					
Escalation factor (Inflation)		1.7%	1.7%	1.7%	***1.7%***
Productivity (50% of Inflation)		-0.9%	-0.9%	-0.9%	
I-X		0.9%	0.9%	0.9%	
Customer growth		1.7%	1.7%	1.7%	***1.7%***
Total Escalation factor		2.6%	2.6%	2.6%	***2.6%***
2013 Revenue Requirement	**817**				
Allowed Revenues - IR with escalation		**838**	**860**	**882**	***2.6%***
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	
SRC impact	-	(61)	(55)	(48)	
	1,021	148	162	223	
Total Allowed Revenues -IR	**1,021**	**986**	**1,022**	**1,105**	***2.6%***
Achieved ROE	**8.9%**	**8.1%**	**8.2%**	**7.7%**	***8.0%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Achieved vs Allowed)		**-1.2%**	**-1.5%**	**-2.4%**	**-1.7%**

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%.

Layering on the existing and new Y factors, and impacts of the new depreciation study results, IR revenue growth of 2.6% was calculated. The forecast average /u annual ROE over the IR term under the I-X model is 1.7% less than forecast /u 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	-0.6%
S6: Same as S4 except I-X equal to the actual effective I-X during 1st Generation IR	-1.7%
	Average Breakeven Escalation factor to achieve the Allowed ROE
S3: Breakeven for S2	3.4%
S5: Breakeven for S4	3.3%

/u

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 $43 million, which /u 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.

<u>The Challenge of Increasing Depreciation and Amortization Expense in an I-X Framework</u>

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 $250 million[1] in 2013 to $304 million in 2016, /u an increase of $54 million over 3 years. The majority of this increase is due to the /u 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 $817 million in 2013 to $925 million in 2016, an /u increase of $108 milllion. In other words, around 50% of the forecast revenue /u

[1] The "adjusted level" is determined by applying the impact of the depreciation rate change to the 2013 base.

growth must be attributed to growth in depreciation and amortization, leaving an estimated $54 million to "pay for" increases in the remaining cost elements, /u 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, 50% of the forecast revenue growth from the formula must /u 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.

BOARD STAFF INTERROGATORY #19

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: A2/T1/S2/P 6 of 15

Enbridge says that "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 horizons, 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."

a) Please document and quantify all the "known or highly probable cost increases over the forecast horizons" which Enbridge did not include in its projected OM&A budgets over the 2014-2016 period.

b) Please document and quantify all the costs which Enbridge is holding flat, "which in reality will not be flat," in its projected OM&A budgets over the 2014-2016 period.

RESPONSE

a) Please see the following table for the quantification of all the known or highly probable cost increases not included within O&M budgets over the forecast horizons. Explanation of the items that are quantified below is set out within the D1 series of Exhibits.

Line No.	Particulars ($ millions)	2014	2015	2016
1).	Merit increase	$1.2	$2.0	$2.5
2).	Employee benefits	2.1	2.2	2.3
3).	Incremental cost to service new customers	1.5	1.6	1.7
4).	Incremental safety and integrity work	8.9	9.1	9.3
5).	External contractor rate increases	0.3	1.4	1.7
6).	Increased volume of locates - compliance with Bill 8	2.6	3.2	3.8
	Highly probable cost increases	$16.5	$19.4	$21.3

1) Merit increase assumed 2.2% in the O&M budget but in reality the merit increase is expected to be around 3.0%.

2) Employee benefits costs are expected to increase 6.1% annually in 2014 and onwards as opposed to 2.2% assumed in the budget.

3) The service work associated with adding new customers is not embedded in the O&M budget. By excluding the incremental costs relating to customer care outsourcing charges which is covered under the CC/CIS service charges, the net impact is $1.5 to $1.7 million each year.

4) The Company has experienced significant requirements for safety and integrity work which has caused the cost to increase more than the inflation rate. The Company has made tremendous efforts to prioritize activities to alleviate the cost pressures.

5) External contractors for Operations are expected to increase their rates between 3% and 6% during the IR term. As a result, the cost increase is more than the inflation rate

6) The Company has experienced a substantial increase for locates requests since the new legislation Bill 8 took effect. Therefore the volume of locates are anticipated to go up at a rate of 6% per annum.

b) Please refer to the following table for the quantification of all the costs which Enbridge is holding flat, “which in reality will not be flat”.

Line No.	Particulars ($ millions)	2014	2015	2016
1).	FTE's	$2.8	$5.7	$8.7
2).	Bad debt expenses	4.7	5.0	5.6
	Total	$7.5	$10.7	$14.3

1) The budget assumes that the Company keeps FTEs flat in the IR term. If FTEs increase 2% (or 47 FTEs) each year assuming 25% O&M and 75% capital, the salary, benefits and other labour related costs would go up significantly for both O&M and capital. The table above indicates the dollar impact for the O&M only.

2) Bad debt expense is forecast to stay flat, but in reality bad debt expense would be expected to increase significantly based on external factors such as gas prices, weather, and economy.

REVENUE (DEFICIENCY) / SUFFICIENCY SUMMARY

1. This evidence presents a summary of EGD's delivery related (deficiency) / sufficiency of the 2013 Board Approved results and the 2014 through 2018 Fiscal Year forecasts. In Updated Exhibit A2, Tab 3, Schedule 1, the Company has set out its proposed rate adjustment process for all years within the Customized Incentive Regulation rate application.

2. The 2014 forecast of revenues, gas cost, and gas in storage amounts have been determined using the gas commodity price, transportation tolls and rates approved by the Board in EGD's October 1, 2013 Quarterly Rate Adjustment Mechanism. The 2014 Gas Supply Plan, Updated 2013-10-29, and approved by the Board in its Decision on Motion dated November 5, 2013, has also been incorporated within this update. The 2015 and 2016 forecast of revenues, gas cost, and gas in storage amounts were completed using the gas commodity price, transportation tolls and rates approved by the Board in EGD's April 1, 2013 Quarterly Rate Adjustment Mechanism (EB-2013-0045 QRAM). The 2017 and 2018 levels of revenues, gas cost, and gas in storage amounts have used the 2016 forecasts as an estimate for 2017 and 2018. As fiscal years 2015 through 2018 will require updated volumes and related gas supply forecast information to be filed in future rate applications to the Board, EGD has not re-forecast the revenue, gas cost and gas in storage amounts for such years as it is not particularly useful to do so.

3. The 2014 fiscal year, as shown at Updated Exhibit F3, Tab 1, Schedule1, page 2, has a required overall return on rate base of 6.74% on a projected rate base of $4,431.6 million. The overall return has embedded within it a forecast 2014 Board Approved return on equity ("ROE") of 9.27%, based on the EB-2009-0084 Board

Approved methodology concerning the cost of capital. Evidence for the ROE% is shown at Exhibit E2, Tab 1, Schedule 1.

4. The 2015 fiscal year, as shown at Exhibit F4, Tab 1, Schedule1, page 2, has a required overall return on rate base of 6.90% on a projected rate base of $4,797.6 million. The overall return has embedded within it a forecast 2015 Board Approved return on equity ("ROE") of 9.72%. Evidence for the ROE% is shown at Exhibit E2, Tab 1, Schedule 1.

5. The 2016 fiscal year, as shown at Exhibit F5, Tab 1, Schedule1, page 2, has a required overall return on rate base of 7.02% on a projected rate base of $5,524.4 million. The overall return has embedded within it a forecast 2016 Board Approved return on equity ("ROE") of 10.12%. Evidence for the ROE% is shown at Exhibit E2, Tab 1, Schedule 1.

6. The 2017 fiscal year, as shown at Exhibit F6, Tab 1, Schedule1, page 2, has a required overall return on rate base of 7.04% on a projected rate base of $5,736.6 million. The overall return has embedded within it a forecast 2017 Board Approved return on equity ("ROE") of 10.17%. Evidence for the ROE% is shown at Exhibit E2, Tab 1, Schedule 2.

7. The 2018 fiscal year, as shown at Exhibit F7, Tab 1, Schedule1, page 2, has a required overall return on rate base of 7.11% on a projected rate base of $5,906.1 million. The overall return has embedded within it a forecast 2018 Board Approved return on equity ("ROE") of 10.27%. Evidence for the ROE% is shown at Exhibit E2, Tab 1, Schedule 2.

8. EGD's revenue sufficiency / (deficiency) for the 2013 Board Approved results, and for the Updated 2014, and originally filed 2015, 2016, 2017 and 2018 fiscal years

are shown below. The table shows a summary of the major components of the revenue sufficiency/ (deficiency).

9. The sufficiency amount calculated for 2014 represents the annual decrease in rates that is required relative to existing October 1st, 2013 Board Approved rates. Additionally, the deficiencies for each of 2015, 2016, 2017 and 2018 have been determined on a cumulative basis in comparison to the April 1st, 2013 Board Approved rates, without any assumption as to what level of rate change might be approved by the Board in 2014 through 2018.

Table 1
Utility Revenue (Deficiency) / Sufficiency

Line No.	($millions)		Board Approved 2013 (1)	Fiscal Year 2014	Fiscal Year 2015	Fiscal Year 2016	Fiscal Year 2017	Fiscal Year 2018
			(a)	(b)	(c)	(d)	(e)	(f)
1.	Revenue at existing rates		2,364.1	2,497.9	2,635.8	2,683.4	2,693.2	2,703.3
2.	Other operating revenue		45.0	40.6	41.0	41.3	41.3	41.3
3.	Total operating revenue	(2)	2,409.1	2,538.5	2,676.8	2,724.7	2,734.5	2,744.6
4.	Revenue requirement:							
5.	Operating costs	(3)	2,078.6	2,187.1	2,356.9	2,423.3	2,446.2	2,468.7
6.	Cost of capital	(4)	283.2	298.9	330.8	387.6	403.8	419.9
7.	Income taxes	(5)	56.4	33.5	13.8	4.5	8.6	15.8
8.	Taxes on (deficiency) / sufficiency		(4.5)	(9.3)	5.5	28.2	39.1	50.9
9.	Customer care smoothing adjustment		(4.6)	(2.9)	(1.1)	0.8	2.9	5.0
10.	Revenue requirement		2,409.1	2,507.3	2,705.9	2,844.4	2,900.6	2,960.3
11.	Revenue (deficiency) / sufficiency	(6)	-	31.2	(29.1)	(119.7)	(166.1)	(215.7)

Notes: (1) 2013 Board Approved revenue includes $6.0 million gross sufficiency.
(2) Provided at Ex. C1.T1.S1.pg.1. line no. 5.
(3) Provided at Ex. D1.T1.S1.pg.1. line no. 6.
(4) Provided at Ex's. F3/F4/F5/F6/F7.T1.S1.pg.2. Col.4, line no. 3.
(5) Provided at Ex. D1.T1.S1.pg.1. line no. 7.
(6) Reference at Ex's. F3/F4/F5/F6/F7.T1.S1.pg.1. Col.4, line no. 14.

ENERGY PROBE INTERROGATORY #11

INTERROGATORY

Ref: Exhibit A1, Tab 2, Schedule 1

Please provide a revised paragraph 6 that shows the impacts of the proposed application, excluding the impact of the proposed treatment of site restoration costs, including the five-year rate rider proposed by EGD.

RESPONSE

The rate impacts in the revised paragraph 6 below were determined using the forecast allowed revenues and resultant deficiency amounts shown in the table below. The table illustrates the allowed revenues and deficiencies if the status quo were maintained and the Company's proposed changes for site restoration costs were removed.

The proposed site restoration cost changes include the implementation of new depreciation rates, and the return of site restoration cost amounts via a five year rate rider, as detailed in Exhibits D1, Tab 5, Schedule 1 and Exhibit D2, Tab 1, Schedule 1.

ALLOWED REVENUE AND DEFICIENCIES (INCL. CIS/CC)
ASSUMING PROPOSED SITE RESTORATION COST CHANGES ARE REMOVED
2014 - 2018 FISCAL YEARS

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Cost of Capital					
1.	Rate base	4,377.0	4,647.2	5,280.1	5,400.4	5,499.5
2.	Required rate of return	6.77%	6.94%	7.08%	7.08%	7.15%
3.		296.5	322.7	373.6	382.3	393.2
	Cost of Service					
4.	Gas costs	1,455.9	1,606.8	1,632.5	1,632.5	1,632.5
5.	Operation and maintenance	425.3	428.5	439.5	450.5	461.8
6.	Depreciation and amortization	292.6	308.3	339.6	350.9	361.2
7.	Fixed financing costs	1.9	1.9	1.9	1.9	1.9
8.	Municipal and other taxes	41.2	43.1	45.5	47.9	50.4
9.		2,216.9	2,388.6	2,459.0	2,483.7	2,507.8
	Miscellaneous operating and non operating revenue					
10.	Other operating revenue	(40.5)	(40.9)	(41.2)	(41.2)	(41.2)
11.	Other income	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
12.		(40.6)	(41.0)	(41.3)	(41.3)	(41.3)
	Income taxes on earnings					
13.	Excluding tax shield	91.0	73.0	68.2	72.8	72.5
14.	Tax shield provided by interest expense	(39.4)	(41.8)	(47.0)	(47.7)	(49.2)
15.		51.6	31.2	21.2	25.1	23.3
	Taxes on deficiency					
16.	Gross deficiency - with CIS/CC	(26.7)	(76.8)	(158.5)	(191.8)	(219.8)
17.	Net deficiency - with CIS/CC	(19.7)	(56.4)	(116.5)	(141.0)	(161.5)
18.		7.1	20.3	42.0	50.8	58.2
19.	Sub-total Allowed Revenue	2,531.5	2,721.8	2,854.5	2,900.6	2,941.2
20.	Customer Care Rate Smoothing Var. Adj.	(2.9)	(1.1)	0.8	2.9	5.0
21.	**Allowed Revenue**	2,528.6	2,720.7	2,855.3	2,903.5	2,946.2
	Revenue at existing Rates					
22.	Gas sales	2,253.5	2,404.3	2,464.5	2,480.3	2,496.2
23.	Transportation service	242.8	229.6	217.1	211.1	205.0
24.	Transmission, compression and storage	1.8	1.8	1.8	1.8	1.8
25.	Rounding adjustment	(0.1)	(0.3)	0.1	0.1	(0.2)
26.	Total	2,498.0	2,635.4	2,683.5	2,693.3	2,702.8
27.	**Gross revenue deficiency**	(30.6)	(85.3)	(171.8)	(210.2)	(243.4)

Based on the above scenario, the revised paragraph 6 from Exhibit A1, Tab 2, Schedule 1, Page 4 would read:

> In the event that Enbridge's application is approved by the Board, the average rate increase for residential customers for 2014 will be approximately 2.4%, or about $14, on a T-Service basis (that is, excluding Gas Supply Charges). The estimated average rate increase for residential customers for 2015 will be approximately 3.4%, or about $20, on a T-Service basis, and the average rate increase to residential customers for 2016 will be approximately 5.2%, or about $31, on the same basis.

Please also note that if the Company were not proposing the Site Restoration Cost refund then paragraph 7 from Exhibit A1, Tab 2, Schedule 1, page 4 would be eliminated.

CME INTERROGATORY #14

INTERROGATORY

Issue: B17

Reference: Exhibit Fl, Tab 1, Schedule 1, page 3
Exhibit Fl, Tab 1, Schedule 3, Appendix A, pages 1 to 4

The evidence indicates that the revenue deficiencies for 2015 to 2018 inclusive are $29.1M, $119.7M, $166.1M and $215.7M respectively. We calculate the total rate increases EGDI is seeking over the four (4) years 2015 to 2018, before adjustments and updates, to be $530.6M, or, on average, about $132.65M per year.

(a) Please list and briefly describe the causes of these escalating year-over-year revenue deficiencies for 2015 over 2014, 2016 over 2015, 2017 over 2016 and 2018 over 2017.

(b) Do these amounts include or exclude the credit for Site Restoration Costs ("SRC")?

RESPONSE

a) Table A on the following page, shows the cumulative Allowed Revenue sufficiency or (deficiency) major elements or causes.

b) The amounts shown exclude the proposed SRC-related amount of $259.8 million to be credited directly as a rate rider. However, the amounts do include the impacts of the proposed change in depreciation rates as per the Gannett Fleming Net Salvage study at Exhibit D2, Tab 1, Schedule 1, and include the impact of tax deductions associated with the rate rider credit proposal.

TABLE A -----EGD UPDATED ALLOWED REVENUE
AND SUFFICIENCY / (DEFICIENCY)
2014 - 2018 FISCAL YEARS

Line No.		Col. 1 2014 Total	Col. 2 2015 Total	Col. 3 2016 Total	Col. 4 2017 Total	Col. 5 2018 Total	Col. 6 Total	
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	
	Elements of sufficiency / (deficiency)							
1.	CIS/Customer Care Agreement	(3.9)	(8.5)	(13.3)	(18.4)	(23.6)	(67.7)	
2.	GTA project revenue requirement	-	(7.0)	(58.8)	(58.7)	(58.6)	(183.1)	
3.	WAMS revenue requirement	-	8.6	(6.3)	(15.9)	(18.1)	(31.7)	
4.	Ottawa reinforcement revenue requirement	(5.0)	(4.8)	(4.8)	(4.8)	(4.8)	(24.2)	
5.	Constant Dollar Depr. Method / SRC change impacts (excl. rate rider)	61.5	54.9	48.2	40.5	23.7	228.8	1
6.	ROE increase (gross) on base rate base	(6.8)	(15.9)	(23.9)	(24.9)	(26.9)	(98.4)	
7.	ROE (gross) on other rate base growth (excl. other major drivers)	(8.2)	(16.1)	(23.6)	(31.2)	(38.2)	(117.3)	
8.	Cost of capital (excl. ROE) change on base rate base	6.3	5.9	6.7	7.3	5.8	32.0	
9.	Cost of capital (excl. ROE) on other rate base growth (excl. other major drivers)	(6.2)	(11.8)	(16.5)	(21.5)	(26.5)	(82.5)	
	O&M increases (excl. Customer Care)							
10.	DSM	(0.8)	(1.4)	(2.1)	(2.8)	(3.5)	(10.6)	
11.	Pension and OPEB	5.6	9.0	11.9	14.3	16.6	57.4	
12.	Other O&M	(12.0)	(14.2)	(23.5)	(32.1)	(40.9)	(122.7)	
13.	Municipal taxes	(1.9)	(3.8)	(6.2)	(8.6)	(11.1)	(31.6)	
14.	Fixed financing charges	0.4	0.4	0.4	0.4	0.4	2.0	
15.	Depreciation increase on "other" rate base growth (excl. other major drivers)	(11.7)	(24.4)	(35.1)	(45.7)	(56.0)	(172.9)	
16.	All other incl. changes in volumes, margin, supply mix, tax adds, tax deducts, interest tax shield, etc.	13.9	-	27.2	36.0	46.0	123.1	1
17.	Sufficiency / (Deficiency) -cumulative	31.2	(29.1)	(119.7)	(166.1)	(215.7)	(499.4)	

Notes:

1. $12.6M of the previously reported total SRC element, of $241.4M, was already captured within the GTA and Ottawa revenue requirement elements. Therefore the all other amounts previously reported (Line No. 16) were subsequently impacted as well.

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. Regulatory Alternatives Considered In Determining This Customized IR Plan

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

Estimated Rate and Bill Impacts including SRC rate rider credit

							Variance	Average
With the GTA Project	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**(2013 - 2018)**	**(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.