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December 11, 2013

VIA RESS, EMAIL and COURIER

Ms. Kirsten Walli
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

**Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
New and Updated Evidence**

Further to Enbridge Gas Distribution's filing of November 22, 2013, attached please find the following new exhibits:

Exhibit A1, Tab 6, Schedule 2 to 4;
Exhibit A2, Tab 11, Schedule 3, Attachment;
Exhibit B6, Tab 1, Schedules 1 to 3;
Exhibit B7, Tab 1, Schedules 1 to 3;
Exhibit C6, Tab 1, Schedules 1 and 2;
Exhibit C6, Tab 2, Schedules 1 and 2;
Exhibit C7, Tab 1, Schedules 1 and 2;
Exhibit C7, Tab 2, Schedules 1 and 2;
Exhibit D1, Tab 8, Schedule 6;
Exhibit D6, Tab 1, Schedule 1;
Exhibit D6, Tab 2, Schedules 1 to 4;
Exhibit D7, Tab 1, Schedule 1;
Exhibit D7, Tab 2, Schedules 1 to 4;
Exhibit E6, Tab 1, Schedules 1 to 5;
Exhibit E7, Tab 1, Schedules 1 to 5;
Exhibit F6, Tab 1, Schedules 1 to 3;
Exhibit F7, Tab 1, Schedules 1 to 3;

Also attached please find the following updated exhibits:

Exhibit A1, Tab 1, Schedule 1;
Exhibit A2, Tab 1, Schedule 1;
Exhibit A2, Tab 1, Schedule 2, pages 1 and 7 to 15;
Exhibit A2, Tab 3, Schedule 1;
Exhibit A2, Tab 5, Schedule 1;
Exhibit A2, Tab 11, Schedule 3;
Exhibit B1, Tab 1, Schedule 1;
Exhibit B1, Tab 1, Schedule 2;
Exhibit B2, Tab 1, Schedule 1;
Exhibit B2, Tab 5, Schedule 5, page 1;
Exhibit C1, Tab 1, Schedule 1;
Exhibit C1, Tab 2, Schedule 1, pages 1, 2, 4, and 5;
Exhibit C1, Tab 2, Schedule 1, Appendix B;
Exhibit D1, Tab 1, Schedule 1;
Exhibit D1, Tab 8, Schedule 1, pages 1 to 3, 12, and 26 to 29;
Exhibit D1, Tab 8, Schedule 2;
Exhibit D1, Tab 17, Schedule 1, page 6;
Exhibit E1, Tab 1, Schedule 1;
Exhibit F1, Tab 1, Schedule 1;
Exhibit F1, Tab 1, Schedule 2, pages 1, 4 and 5;

This submission was filed through the Ontario Energy Board's RESS and will be available on the Company's website at www.enbridgegas.com/ratecase.

Please contact the undersigned if you have any questions.

Yours truly,

[original signed]

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

CURRICULUM VITAE OF
IRENE CHAN

Experience: Enbridge Gas Distribution

Senior Manager, Productivity and Business Analytics
2013

Manager, Gas Accounting and Analytics
2012

Manager, Margin Accounting, and Gas Analytics
2011

Manager, Margin Accounting, Business Performance and Analytics
2010

Manager, Margin Budgets and Accounting
2007

Manager, Margin Planning and Analysis
2006

Manager, Volumetric Analysis and Budgets
2003

Supervisor, Volumetric Analysis
2001

Senior Analyst, Volumes Knowledge Centre
2000

Economic Analyst, Economic Studies
1998

Queen's University

Instructor, Economics Department
1997

Research/Teaching Assistant, Economics Department
1992-1997

International Monetary Fund

Summer Intern, Research Department
1996

Consultant, Research Department
1994

Bank of Canada

Research Assistant, Research Department
1991

Education: Certified Management Accountant,
The Society of Management Accountants of Canada, 2006

Ph.D. in Economics
Queen's University, 1998

Master of Arts in Economics
Queen's University, 1993

Bachelor of Arts (Honours) in Economics
University of Western Ontario, 1991

Memberships: Toronto Association for Business & Economics
The Society of Management Accountants of Canada

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0008
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2002-0133

CURRICULUM VITAE OF
CATHY EGAN

Experience: Enbridge Gas Distribution Inc.

Director of System Measurement, Quality & Training
2013

Director of Safety
2012

Director of Safety & Training
2010

General Manager, Niagara Region
2008

President & General Manager, St. Lawrence Gas
2006

Group Manager, Work Management Centre
2005

Manager, New Construction & Mass Markets
2002

Manager, Mass Markets
2001

Market Sector Manager
1999

Group Manager Energy Efficiency Programs
1998

Manager, Distribution Expansion CR & NR
1997

Manager, Customer Attachment
1995

Manager, Metro Call Distribution Center
1994

Senior Supervisor Customer Inquiry
1991

Supervisor, Customer Service
1990
Representative, Telephone Service
1990

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

CURRICULUM VITAE OF
CATHERINE HO, CPA, CA

Experience: Enbridge Gas Distribution Inc.

Manager, Accounting
2012

Manager, Gas Accounting
2012

Manager, Finance Projects
2008

Senior Audit Advisor
2005

Ernst & Young LLP

Senior Staff Accountant
2004

Horwath Orenstein LLP

Staff Accountant
2002

Goldfarb, Shulman, Patel & Co. LLP

Staff Accountant
2000

Education: Chartered Accountant, 2005

Certified Public Accountant – Delaware, 2004

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

Memberships: Institute of Chartered Accountants of Ontario (ICAO)

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

CURRICULUM VITAE OF
TREVOR W. TUCK

Experience:	Enbridge Gas Distribution Inc.
	Director, Distribution Protection 2013 to Present
	Manager, Operations Central Region East 2011 – 2013
	Manager, Work Management Centre Operations 2008 – 2010
	Manager, Engineer Capital Projects ESTS 2007 - 2008
	Manager, Special Projects ESTS 2006 - 2007
	Manager, Engineering Special Projects 2005
	Project Manager, Engineering 2004
	Project Engineer, Industrial Thermo Polymer Inc. 2002
	Project Engineer, Applied Materials Japan Inc. 2001
	Instructor, Aeon Inc. 2000
	Mechanical Designer, Silex Inc. 1999
	Mechanical Designer, Samuel Acme Inc. 1998
Education:	Masters of Business Administration, Finance Schulich School of Business, York University, 2006
	Bachelor of Applied Science, Mechanical Engineering University of Windsor 1998
Memberships:	Professional Engineers Ontario
Appearances:	(Ontario Energy Board) EB-2006-0034

CURRICULUM VITAE OF
THO VUONG, P.Eng.

Experience:	Enbridge Gas Distribution Inc.
	Manager, System Measurement 2011
	Construction Manager, Central Region West 2008
	Manager, Work Management Centre 2006
	Project Manager, FieldVision 2004
	Manager, Joint Utility Construction 2002
	Project Leader, Engineering 2000
	Supervisor, Special Projects 1999
	Supervisor, Planning and Technical Services 1998
	Supervisor, Construction and Maintenance 1997
	Pipeline Inspector, Construction 1995
Education:	Professional Engineer (P.Eng.), 1997 B.A.Sc., University of Waterloo, 1995
Memberships:	Professional Engineers Ontario
Appearances:	(Ontario Energy Board) None

Julia Frayer

Managing Director

LONDON ECONOMICS

KEY QUALIFICATIONS:

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

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

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

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

EDUCATION:

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

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

EMPLOYMENT RECORD:

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

MOST RECENT PROJECT EXPERIENCE

PBR AND RATE DESIGN RELATED

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

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

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

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

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

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

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

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

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

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

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

OTHER EXPERT TESTIMONY

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

Date:	2013
Location:	United States

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

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

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

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

Date:	2011-2012
Location:	Alberta, Canada

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

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

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

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

Date:	2011

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

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

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

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

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

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

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

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

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

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

Date:	2009-2010
Location:	United States

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

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

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

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

Date:	2009

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

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

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

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

Date:	2009
Location:	United States
Company:	NRG

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

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

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

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

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

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

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

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

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

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

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

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

Date:	2008
Location:	United States
Company:	Private Client

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

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

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

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

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

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

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

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

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

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

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

MARKET ANALYSIS

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

Date:	2013
Location:	United States
Company:	Private client

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

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

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

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

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

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

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

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

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

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

Date:	2012
Location:	United States
Company:	Private company

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

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

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

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

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

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

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

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

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

Date:	2011
Location:	United States
Company:	Private Client

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

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

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

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

Date:	2011
Location:	New England

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

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

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

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

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

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

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

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

Date:	2005
Location:	United States
Company:	Private Client

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

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

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

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

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

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

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

Date:	2004-2005

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

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

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

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

Date:	2004
Location:	United States
Company:	Private Clients

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

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

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

SPEAKING ENGAGEMENTS:

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

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

LANGUAGES:

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

EXECUTIVE BIOGRAPHIES

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

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

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

Evaluation of Enbridge Gas Distribution's updated Sustainable Efficiency Incentive Mechanism

Prepared by London Economics International ("LEI") for Enbridge Gas Distribution Inc. ("EGD")

December 11th, 2013

Enbridge Gas Distribution Inc. ("EGD") updated its proposed Sustainable Efficiency Incentive Mechanism ("SEIM") in response to the suggestions and comments from stakeholders on the originally proposed SEIM. LEI reviewed the updated SEIM and finds that the updated SEIM meets the objectives of the Ontario Energy Board ("OEB" or the "Board") and is consistent with the principles of an efficiency carryover mechanism ("ECM"). Furthermore, the updated SEIM addresses concerns raised by Stakeholders and incorporates features that would strengthen the utility's incentives to seek out and implement sustainable longer term incentives, even at the end of the Incentive Regulation ("IR") term.

1. Updated SEIM addresses concerns raised by Stakeholders

As described in the updated SEIM filed by EGD under Exhibit A2, Tab 11, Schedule 3, EGD modified its proposed SEIM to respond to various criticisms from stakeholders of its original SEIM, including yearly reward of the SEIM payout during the IR term, no cap on the SEIM payout, and SEIM payout based on forecasted or estimated benefits rather than actual benefits.

To address these concerns, EGD is incorporating the following new features in its updated SEIM:

- the SEIM is now calculated **based on EGD's performance during the IR term** and not on future undertakings;
- EGD has the **burden of proof** to show that it deserves the reward by demonstrating that the benefits of the initiatives to customers outweigh the costs to customers of the SEIM reward. In addition, the SEIM has safeguards against short-term cost reductions that may undermine service quality. In the request for SEIM award, the utility will demonstrate that service quality was not degraded and that it has at least met or exceeded performance targets; and
- there is a **cap** on the SEIM reward which mitigates some of the cost increase exposure to customers at re-setting and is consistent with goal of managing rate volatility.

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2. Updated SEIM meets the OEB objectives

Given the concerns raised by stakeholders, LEI evaluated how the updated SEIM meets the Board's objectives. LEI finds EGD's updated SEIM consistent with the objectives of the OEB as discussed below.

- ***Protect consumers in respect of price and reliability:*** consumers are protected because EGD will only receive an SEIM reward if it can demonstrate that the net present value ("NPV") of the benefits to consumers of the programs or initiatives undertaken are greater than the amount of the reward. In addition, EGD has to prove that it had performed over the term of the IR plan consistent with its overall Service Quality Requirements ("SQR"). This ensures that any reductions in costs are not made at the expense of service quality. Furthermore, there is a cap to the amount of reward that EGD can receive under the SEIM. The two-year payout window of the reward also protects consumers from rate volatility.

- ***Encourage efficient utility***: the goal of the updated SEIM, similar to the goal of the original SEIM, is to produce incentives for management to undertake long-term sustainable efficiencies, and to reduce the potential motivations for management to otherwise delay efficiency-enhancing projects at the end of the IR term. In particular, through the "carrot" of the potential "reward" on the next term, the SEIM will encourage management to pursue initiatives where benefits may accrue beyond the term of the current IR plan.

- ***Quality of service***: SEIM ensures that EGD maintains or exceeds its current service performance as EGD will only receive the reward if it can demonstrate that it was able to do this for at least three of the five years of the IR term.

- ***Industry financial viability***: SEIM will not undermine EGD's viability. The rewards to the updated SEIM are in line with the risks that EGD is taking in the other elements of the IR Plan. For example, EGD's IR plan has an asymmetric earnings sharing mechanism ("ESM") which will not shift any risk of under-delivery of productivity gains to customers. Moreover, as a complement to the risks that EGD takes on, the SEIM reward would not be paid if the average actual return on equity ("ROE") is below the average allowed ROE for the IR term.

3. Updated SEIM is consistent with the common characteristics of an ECM

LEI had reviewed the experiences of other jurisdictions that rely on building blocks approach to incentive ratemaking. The updated SEIM is in line with ECMs used in other jurisdictions. LEI reviewed the ECMs currently being implemented in Alberta, and the ECMs that have been used

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in Australia and the UK. Please see the Appendix (on page 4) for the comparative table of the differences and similarities of these other jurisdictions' ECMs and EGD's updated SEIM.

Based on our knowledge of other implemented ECMs and the Customized IR plan that EGD has proposed, it is our opinion that the updated SEIM possesses all the core features of a generic ECM:

First, an ECM should provide the utility with an **ongoing incentive to operate efficiently throughout the entire regulatory period**. This is to address the issue that the utility will target efficiency gains in the early years of a regulatory period only. The SEIM award provides the incentive to management, as it will be a material payment, if it is approved by the Board on review of the SEIM application. At the same time, the SEIM award would only be paid if the utility can demonstrate that it has taken initiatives that have produced and will produce a stream of benefits to ratepayers that exceed the SEIM award. Therefore, the SEIM award is tied directly to productivity undertakings by the utility.

Second, the ECM should **allow a utility to carryover the incremental earnings from efficiency gains into the next regulatory period**. Under the updated SEIM, the reward will be carried over in the first two years of the next term (or 2019 and 2020). This is similar to the payout system of the Alberta's ECM.

Third, an ECM should **only target efficiency gains** and not apply to windfall gains or other unexpected cost savings. To ensure that the SEIM reward is not based on cost reductions due to factors external to the business like lower interest rates, EGD's updated SEIM requires that the utility demonstrate that the reward is justified. This is done by showing that the NPV of the expected benefits from the initiatives performed during the IR term is greater than the payment of the SEIM reward. In addition, EGD has to show that, on average over the 5-year period, it has been able to maintain or exceed its performance listed in the Performance Metrics Benchmarking Report. Lastly, EGD has to prove that it has maintained SQR performance at or above the 2013 level for at least three of the five years of the IR term.

Lastly, an ECM should **reward utilities after they have achieved efficiency gains**. With the updated SEIM, EGD will be rewarded only after efficiency initiatives have been implemented. Although the benefits of those efficiency initiatives may flow to customers for some time, the Board and stakeholders will have the benefit of knowing specific initiatives that have led to those benefits.

Overall, the updated SEIM generates sustainable, multi-year incentives and is consistent with well-designed ECMs.

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4. Appendix: Comparative review of SEIM with carryover mechanisms in other jurisdictions

Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
Alberta *(ROE ECM)*	**Amount of Reward**: Difference between average approved ROEs and average actual ROEs for the prior) regulatory period. **Calculated Features of the Reward**: - partial true up (50%); - only positive differences in ROEs; and - reward cap of 0.5%. **Timing of Payment and Payment Period of Reward**: The SEIM Reward will be paid out over a two year timeframe after the end of the IR term, such that the payout can effectively motivate management to continue to carry out efficiency-enhancing projects at the end of the IR term.	**Basis for Reward:** EGD is proposing to base the reward on an analysis of benefits to consumers from achieved and future efficiency gains, therefore such benefits need to exceed the reward amount. In Alberta, the ECM was triggered on the basis of ROE overearnings, without the need for substantiating the productivity achieved and without the review of specific initiatives that improved productivity.	- AUC Decision 2012-237 (September 12, 2012)
Australia *(Opex Efficiency*	**Basis for Reward:** EGD is proposing to document	**Calculation of Reward**: EBSS calculates the carryover rewards based	- AER (November 2013) *Better Regulation: Efficiency*

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Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
Benefit Sharing Scheme for Electricity Network Service Providers mechanism)	achieved productivity gains. Likewise, EBSS is also awarded if there is improvement in operating expenditure ("opex") performance. **Timing of Payment of Reward**: Rewards will be awarded on the next regulatory period. **Risk/Reward:** EBSS has both rewards and penalties; rewards are shared with customers at a ratio of about 30% for utilities to 70% for customers. Likewise, EGD's SEIM reward is consistent with the risks that EGD is taking in the other elements of the IR plan. EGD is already taking the risks in its proposed asymmetric ESM, where under-performance is solely the financial responsibility of utility management and shareholders. In addition, the SEIM reward is authorized only if EGD's financial	on difference between forecasted and actual opex, while EGD (for simplicity) is using the difference in actual and allowed ROEs. **Payment Period of Rewards**: EGD is proposing a two-year payout for the next term while EBSS involves rolling where the carryover period is currently set as five years.[1]	*Benefit Sharing Scheme for Electricity Network Service Providers.*

[1] If IR term is not equal to 5 years, AER may decide to change the carryover period.

Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
	performance exceeds expectations (in other words, if average actual ROE exceeds allowed ROE).		
UK *(Carry-over mechanism for network output measures ("NOM"))*	**Basis of Reward (period):** Performance ***over the whole IR term*** is used to determine carry-over/catch-up for the next IR term. **Timing of Payment d of Reward**: Rewards will be awarded on the next regulatory period. **Risk/Reward:** NOM Carryover has reward of 2.5% of additional costs of material over-delivery, and penalty of 2.5% of avoided costs of material under-delivery. Similarly, EGD's SEIM reward is consistent with the risks that EGD is taking in the other elements of the IR plan. EGD is already taking on risks of under-performance in its proposed	**Calculation of Amount of Return:** While SEIM uses actual and approved ROEs, UK's NOM Carryover is based on achievement of target "Outputs" based on what is set by Ofgem at the start of the regulatory period. (Note: "Outputs" include performance metrics in such areas as asset health, asset load/capacity utilisation, secondary deliverables, as well as safety). **Calculation of Reward**: UK compares target and actual NOMs; carry-overs (awards) or catch-ups (charges) are estimated if actual NOMs are not on target. The payout under the NOM Carryover is based on the "estimate [of] the costs associated with the under or over delivery against the NOMs target… based on the	- Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation.*

Jurisdiction	Similarities with updated SEIM	Differences with updated SEIM	Sources
	asymmetric ESM. Furthermore, the SEIM reward would be approved only if the average actual ROE exceeded the average allowed ROE for the term of the IR plan.	underlying asset volume and relevant unit costs."[2] **Payment Period of Reward**: While SEIM's reward is proposed to be paid out in two years for the next term, the carryover for NOM is paid out for entire next term (which is currently set as 8 years).	

[2] Ofgem. *RIIO-GD1: Final Proposals - Supporting Document – Outputs, incentives and innovation*. December 2012, pp. 68-70. Available online at https://www.ofgem.gov.uk/ofgem-publications/48155/2riiogd1fpoutputsincentivesdec12.pdf.

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UTILITY RATE BASE
2017 FORECAST YEAR

Line No.		Col. 1 2017 Forecast Year Excl. CIS & Customer Care	Col. 2 2017 Forecast Year CIS & Customer Care	Col. 3 Total 2017 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	8,686.6	127.1	8,813.7
2.	Accumulated depreciation	(3,258.4)	(107.4)	(3,365.8)
3.	Net property, plant, and equipment	5,428.2	19.7	5,447.9
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	40.0	-	40.0
11.	Total Working Capital	288.7	-	288.7
12.	Utility Rate Base	5,716.9	19.7	5,736.6

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	403.5	(141.3)	262.2
2.	Distribution plant	7,865.4	(2,907.6)	4,957.8
3.	General plant	427.4	(210.5)	216.9
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	8,696.8	(3,259.9)	5,436.9
6.	Plant held for future use	1.7	(1.3)	0.4
7.	Sub- total	8,698.5	(3,261.2)	5,437.3
8.	Affiliate Shared Assets Value	(11.9)	2.8	(9.1)
9.	Total property, plant, and equipment	8,686.6	(3,258.4)	5,428.2

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-
2.	Land and gas storage rights (450/451)	45.5	-	-	45.5	(1.0)	44.5	44.5
3.	Structures and improvements (452.00)	44.1	6.6	(0.5)	50.3	(0.1)	50.2	45.2
4.	Wells (453.00)	65.2	2.6	-	67.7	-	67.7	65.7
5.	Well equipment (454.00)	9.6	-	-	9.6	-	9.6	9.6
6.	Field Lines (455.00)	69.4	1.1	(0.1)	70.5	-	70.5	69.6
7.	Compressor equipment (456.00)	113.7	0.2	-	113.9	(0.5)	113.4	113.3
8.	Measuring and regulating equipment (457.00)	14.7	0.0	-	14.8	-	14.8	14.7
9.	Base pressure gas (458.00)	41.0	-	-	41.0	-	41.0	41.0
10.	Total	403.1	10.5	(0.6)	413.1	(1.5)	411.6	403.5

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2017	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2017	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(24.6)	(0.5)	-	-	-	(25.0)	-	(25.0)	(24.8)
3.	Structures and improvements (452.00)	(7.0)	(0.8)	-	0.5	-	(7.3)	0.1	(7.2)	(7.1)
4.	Wells (453.00)	(19.5)	(1.0)	(0.0)	-	-	(20.5)	-	(20.5)	(20.0)
5.	Well equipment (454.00)	(7.2)	(0.5)	-	-	-	(7.8)	-	(7.8)	(7.5)
6.	Field Lines (455.00)	(27.4)	(1.1)	(0.1)	0.1	-	(28.5)	-	(28.5)	(28.0)
7.	Compressor equipment (456.00)	(45.2)	(3.1)	(0.1)	-	-	(48.4)	0.2	(48.2)	(46.6)
8.	Measuring and regulating equipment (457.00)	(7.1)	(0.5)	(0.0)	-	-	(7.6)	-	(7.6)	(7.4)
9.	Total	(138.0)	(7.4)	(0.3)	0.6	-	(145.1)	0.3	(144.8)	(141.3)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	29.0	-	-	29.0	-	29.0	29.0
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	96.8	-	-	96.8	-	96.8	96.8
4.	Structures and improvements (472.00)	137.5	6.5	(0.4)	143.6	(0.3)	143.3	140.1
5.	Services, house reg & meter install. (473/474)	2,559.9	136.3	(22.6)	2,673.5	-	2,673.5	2,611.7
6.	NGV station compressors (476)	2.6	0.1	(0.1)	2.6	-	2.6	2.5
7.	Meters (478)	449.7	26.7	(13.5)	462.8	-	462.8	454.3
8.	Sub-total	3,275.5	169.6	(36.7)	3,408.4	(0.3)	3,408.0	3,334.4
9.	Mains (475)	3,912.2	177.6	(4.0)	4,085.8	(2.2)	4,083.6	3,987.3
10.	Measuring and regulating equip. (477)	531.0	33.3	(2.0)	562.2	(0.5)	561.7	543.7
11.	Sub-total	4,443.2	210.9	(6.1)	4,648.1	(2.7)	4,645.3	4,531.0
12.	Total	7,718.7	380.5	(42.7)	8,056.4	(3.1)	8,053.4	7,865.4

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2017	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2017	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(3.4)	(1.1)	-	-	-	(4.6)	-	(4.6)	(4.0)
2.	Structures and improvements (472.00)	(28.5)	(9.0)	-	0.4	0.3	(36.9)	0.2	(36.6)	(32.4)
3.	Services, house reg & meter install. (473/474)	(1,040.1)	(64.4)	19.3	22.6	12.7	(1,049.9)	-	(1,049.9)	(1,044.2)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.0)	-	(2.0)	(2.0)
5.	Meters (478)	(209.7)	(41.8)	-	13.5	-	(238.0)	-	(238.0)	(223.7)
6.	Mains (475)	(1,355.8)	(104.2)	34.0	4.0	2.2	(1,419.8)	1.9	(1,417.9)	(1,383.0)
7.	Measuring and regulating equip. (477)	(214.2)	(11.7)	0.2	2.0	-	(223.7)	0.5	(223.1)	(218.3)
8.	Total	(2,853.7)	(232.3)	53.4	42.7	15.2	(2,974.7)	2.7	(2,972.1)	(2,907.6)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	17.3	0.3	-	17.6	(0.2) [1]	17.4	17.1
2.	Office furniture and equipment (483.00)	34.1	4.4	(1.0)	37.4	-	37.4	34.6
3.	Transportation equipment (484.00)	56.9	3.7	(0.9)	59.7	(0.1) [1]	59.6	57.2
4.	NGV conversion kits (484.01)	8.2	0.1	(0.3)	8.0	-	8.0	8.1
5.	Heavy work equipment (485.00)	24.3	1.3	(0.3)	25.3	-	25.3	24.5
6.	Tools and work equipment (486.00)	39.8	1.5	(1.1)	40.2	-	40.2	39.7
7.	Rental equipment (487.70)	5.2	1.4	(0.0)	6.6	-	6.6	5.5
8.	NGV rental compressors (487.80)	9.0	2.2	(0.3)	11.0	-	11.0	9.4
9.	NGV cylinders (484.02 and 487.90)	3.9	0.6	(0.0)	4.4	-	4.4	4.0
10.	Communication structures & equip. (488)	3.9	-	-	3.9	-	3.9	3.9
11.	Computer equipment (490.00)	35.2	8.2	(6.9)	36.5	-	36.5	33.8
12.	Software Aquired/Developed (491.00)	125.4	22.8	(31.2)	116.9	-	116.9	119.0
13.	CIS (491.00)	127.1	-	-	127.1	(127.1) [2]	-	-
14	WAMS (489.00)	70.6	-	-	70.6	-	70.6	70.6
14.	Total	560.8	46.4	(42.0)	565.3	(127.4)	437.9	427.4

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2017 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2017 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(8.3)	(1.1)	-	-	(9.4)	0.2 [1]	(9.3)	(8.7)
2.	Office furniture and equipment (483.00)	(14.5)	(3.4)	1.0	-	(16.8)	-	(16.8)	(15.6)
3.	Transportation equipment (484.00)	(28.7)	(6.0)	0.9	-	(33.8)	0.1 [1]	(33.7)	(31.2)
4.	NGV conversion kits (484.01)	(6.7)	(0.7)	0.3	-	(7.1)	-	(7.1)	(6.9)
5.	Heavy work equipment (485.00)	(9.8)	(0.9)	0.3	-	(10.4)	-	(10.4)	(10.1)
6.	Tools and work equipment (486.00)	(17.3)	(1.6)	1.1	-	(17.8)	-	(17.8)	(17.6)
7.	Rental equipment (487.70)	(1.0)	(0.0)	0.0	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.9)	(0.8)	0.3	-	(3.4)	-	(3.4)	(3.2)
9.	NGV cylinders (484.02 and 487.90)	(3.1)	(0.4)	0.0	-	(3.5)	-	(3.5)	(3.3)
10.	Communication structures & equip. (488)	(2.2)	(0.4)	-	-	(2.6)	-	(2.6)	(2.4)
11.	Computer equipment (490.00)	(32.7)	(12.4)	6.9	-	(38.2)	-	(38.2)	(35.5)
12.	Software Aquired/Developed (491.00)	(67.1)	(27.1)	31.2	-	(62.9)	-	(62.9)	(65.2)
13.	CIS (491.00)	(92.2)	(12.7)	-	-	(104.9)	104.9 [2]	-	-
14	WAMS (489.00)	(6.4)	(7.1)	-	-	(13.4)	-	(13.4)	(9.9)
15	Total	(292.8)	(74.5)	42.0	-	(325.4)	105.1	(220.3)	(210.5)

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

Witness: K. Culbert

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

Witness: K. Culbert

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2017	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2017	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

Witness: K. Culbert

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: K. Culbert

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2017	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2017	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)
2.	Total	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)

Witness: K. Culbert

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.4	34.1	-	(65.6)	0.6	381.4	40.0	391.9
2.	January 31	1.4	34.2	-	(65.1)	0.7	227.6	40.0	238.8
3.	February	1.4	34.3	-	(64.3)	0.4	105.1	40.0	116.9
4.	March	1.4	34.4	-	(64.3)	0.5	36.8	40.0	48.8
5.	April	1.4	34.5	-	(64.2)	1.0	48.3	40.0	61.0
6.	May	1.4	34.5	-	(64.2)	0.9	116.4	40.0	129.0
7.	June	1.4	34.6	-	(64.1)	0.9	203.5	40.0	216.3
8.	July	1.3	34.7	-	(64.1)	0.8	299.5	40.0	312.2
9.	August	1.3	34.8	-	(64.1)	2.2	396.1	40.0	410.3
10.	September	1.3	34.9	-	(64.8)	1.7	481.3	40.0	494.4
11.	October	1.3	34.9	-	(65.2)	1.1	524.4	40.0	536.5
12.	November	1.3	35.0	-	(65.9)	0.7	495.5	40.0	506.6
13.	December	1.3	35.1	-	(65.1)	0.6	380.0	40.0	391.9
14.	Avg. of monthly avgs.	1.4	34.6	-	(64.6)	1.0	276.3	40.0	288.7

Witness: K. Culbert

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2017 FORECAST YEAR

Line No.		Col. 1 Disbursements	Col. 2 Net Lag-Days	Col. 3 Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,647.2	8.8	39.7
2.	Items not subject to working cash allowance (Note 1)	(14.7)		
3.	Gas costs charged to operations	1,632.5		
4.	Operation and Maintenance	346.1		
5.	Less: Storage costs	(8.4)		
6.	Operation and maintenance costs subject to working cash	337.7		
7.	Ancillary customer services	-		
8.		337.7	(4.4)	(4.1)
9.	Sub-total			35.6
10.	Storage costs	8.4	64.9	1.5
11.	Storage municipal and capital taxes	1.4	29.4	0.1
12.	Sub-total			1.6
13.	Harmonized Sales Tax			2.8
14.	Total working cash allowance			40.0

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

Witness: K. Culbert

UTILITY RATE BASE
2018 FORECAST YEAR

Line No.		Col. 1 2018 Forecast Year Excl. CIS & Customer Care	Col. 2 2018 Forecast Year CIS & Customer Care	Col. 3 Total 2018 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	9,042.2	127.1	9,169.3
2.	Accumulated depreciation	(3,431.7)	(120.1)	(3,551.8)
3.	Net property, plant, and equipment	5,610.5	7.0	5,617.5
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	39.9	-	39.9
11.	Total Working Capital	288.6	-	288.6
12.	Utility Rate Base	5,899.1	7.0	5,906.1

Witness: K. Culbert

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	413.4	(148.4)	265.0
2.	Distribution plant	8,206.6	(3,054.3)	5,152.3
3.	General plant	431.9	(229.9)	202.0
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	9,052.4	(3,433.1)	5,619.3
6.	Plant held for future use	1.7	(1.4)	0.3
7.	Sub- total	9,054.1	(3,434.5)	5,619.6
8.	Affiliate Shared Assets Value	(11.9)	2.8	(9.1)
9.	Total property, plant, and equipment	9,042.2	(3,431.7)	5,610.5

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-
2.	Land and gas storage rights (450/451)	45.5	-	-	45.5	(1.0)	44.5	44.5
3.	Structures and improvements (452.00)	50.3	6.6	(0.5)	56.4	(0.1)	56.3	51.3
4.	Wells (453.00)	67.7	2.6	-	70.3	-	70.3	68.2
5.	Well equipment (454.00)	9.6	-	-	9.6	-	9.6	9.6
6.	Field Lines (455.00)	70.5	1.1	(0.1)	71.5	-	71.5	70.7
7.	Compressor equipment (456.00)	113.9	0.2	-	114.1	(0.5)	113.7	113.5
8.	Measuring and regulating equipment (457.00)	14.8	0.0	-	14.8	-	14.8	14.8
9.	Base pressure gas (458.00)	41.0	-	-	41.0	-	41.0	41.0
10.	Total	413.1	10.5	(0.6)	423.0	(1.5)	421.5	413.4

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2018	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2018	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(25.0)	(0.5)	-	-	-	(25.5)	-	(25.5)	(25.3)
3.	Structures and improvements (452.00)	(7.3)	(0.9)	-	0.5	-	(7.7)	0.1	(7.6)	(7.4)
4.	Wells (453.00)	(20.5)	(1.1)	(0.0)	-	-	(21.6)	-	(21.6)	(21.0)
5.	Well equipment (454.00)	(7.8)	(0.5)	-	-	-	(8.3)	-	(8.3)	(8.0)
6.	Field Lines (455.00)	(28.5)	(1.1)	(0.0)	0.1	-	(29.6)	-	(29.6)	(29.1)
7.	Compressor equipment (456.00)	(48.4)	(3.1)	(0.0)	-	-	(51.5)	0.2	(51.3)	(49.8)
8.	Measuring and regulating equipment (457.00)	(7.6)	(0.5)	-	-	-	(8.1)	-	(8.0)	(7.8)
9.	Total	(145.1)	(7.6)	(0.1)	0.6	-	(152.2)	0.3	(151.9)	(148.4)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	29.0	-	-	29.0	-	29.0	29.0
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	96.8	-	-	96.8	-	96.8	96.8
4.	Structures and improvements (472.00)	143.6	6.5	(0.4)	149.7	(0.3)	149.4	146.2
5.	Services, house reg & meter install. (473/474)	2,673.5	136.3	(22.6)	2,787.2	-	2,787.2	2,725.3
6.	NGV station compressors (476)	2.6	0.1	(0.1)	2.6	-	2.6	2.5
7.	Meters (478)	462.8	26.7	(13.5)	476.0	-	476.0	467.4
8.	Sub-total	3,408.4	169.6	(36.7)	3,541.2	(0.3)	3,540.9	3,467.3
9.	Mains (475)	4,085.8	182.4	(4.0)	4,264.2	(2.2)	4,262.0	4,164.3
10.	Measuring and regulating equip. (477)	562.2	33.3	(2.0)	593.5	(0.5)	592.9	575.0
11.	Sub-total	4,648.1	215.7	(6.1)	4,857.7	(2.7)	4,854.9	4,739.3
12.	Total	8,056.4	385.2	(42.7)	8,398.9	(3.1)	8,395.8	8,206.6

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2018	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2018	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(4.6)	(1.1)	-	-	-	(5.7)	-	(5.7)	(5.1)
2.	Structures and improvements (472.00)	(36.9)	(9.5)	-	0.4	0.3	(45.7)	0.3	(45.5)	(41.0)
3.	Services, house reg & meter install. (473/474)	(1,049.9)	(67.2)	5.9	22.6	12.7	(1,075.9)	-	(1,075.9)	(1,063.2)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.1)	-	(2.1)	(2.0)
5.	Meters (478)	(238.0)	(43.1)	-	13.5	-	(267.5)	-	(267.5)	(252.7)
6.	Mains (475)	(1,419.8)	(108.4)	11.6	4.0	2.2	(1,510.4)	2.0	(1,508.4)	(1,462.1)
7.	Measuring and regulating equip. (477)	(223.7)	(12.3)	0.0	2.0	-	(233.9)	0.6	(233.3)	(228.2)
8.	Total	(2,974.7)	(241.8)	17.5	42.7	15.2	(3,141.1)	2.8	(3,138.4)	(3,054.3)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	17.6	0.3	-	17.9	(0.2) [1]	17.7	17.4
2.	Office furniture and equipment (483.00)	37.4	4.4	(1.0)	40.8	-	40.8	38.0
3.	Transportation equipment (484.00)	59.7	3.7	(0.9)	62.4	(0.1) [1]	62.4	60.0
4.	NGV conversion kits (484.01)	8.0	0.1	(0.3)	7.9	-	7.9	7.9
5.	Heavy work equipment (485.00)	25.3	1.3	(0.3)	26.4	-	26.4	25.5
6.	Tools and work equipment (486.00)	40.2	1.5	(1.1)	40.6	-	40.6	40.1
7.	Rental equipment (487.70)	6.6	1.4	(0.0)	8.0	-	8.0	6.9
8.	NGV rental compressors (487.80)	11.0	2.2	(0.3)	12.9	-	12.9	11.4
9.	NGV cylinders (484.02 and 487.90)	4.4	0.6	(0.0)	5.0	-	5.0	4.5
10.	Communication structures & equip. (488)	3.9	-	-	3.9	-	3.9	3.9
11.	Computer equipment (490.00)	36.5	8.2	(6.9)	37.8	-	37.8	35.1
12.	Software Aquired/Developed (491.00)	116.9	22.8	(31.2)	108.5	-	108.5	110.6
13.	CIS (491.00)	127.1	-	-	127.1	(127.1) [2]	-	-
14	WAMS (489.00)	70.6	-	-	70.6	-	70.6	70.6
15	Total	565.3	46.4	(42.0)	569.7	(127.4)	442.4	431.9

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2018 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2018 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(9.4)	(1.1)	-	-	(10.6)	0.2 [1]	(10.4)	(9.8)
2.	Office furniture and equipment (483.00)	(16.8)	(3.7)	1.0	-	(19.4)	-	(19.4)	(18.1)
3.	Transportation equipment (484.00)	(33.8)	(6.3)	0.9	-	(39.2)	0.1 [1]	(39.1)	(36.4)
4.	NGV conversion kits (484.01)	(7.1)	(0.7)	0.3	-	(7.6)	-	(7.6)	(7.4)
5.	Heavy work equipment (485.00)	(10.4)	(0.9)	0.3	-	(11.1)	-	(11.1)	(10.7)
6.	Tools and work equipment (486.00)	(17.8)	(1.6)	1.1	-	(18.4)	-	(18.4)	(18.1)
7.	Rental equipment (487.70)	(1.0)	(0.1)	0.0	-	(1.1)	-	(1.1)	(1.1)
8.	NGV rental compressors (487.80)	(3.4)	(0.9)	0.3	-	(4.1)	-	(4.1)	(3.7)
9.	NGV cylinders (484.02 and 487.90)	(3.5)	(0.5)	0.0	-	(3.9)	-	(3.9)	(3.7)
10.	Communication structures & equip. (488)	(2.6)	(0.4)	-	-	(3.0)	-	(3.0)	(2.8)
11.	Computer equipment (490.00)	(38.2)	(12.8)	6.9	-	(44.1)	-	(44.1)	(41.2)
12.	Software Aquired/Developed (491.00)	(62.9)	(24.7)	31.2	-	(56.4)	-	(56.4)	(59.8)
13.	CIS (491.00)	(104.9)	(12.7)	-	-	(117.6)	117.6 [2]	-	-
14	WAMS (489.00)	(13.4)	(7.1)	-	-	(20.5)	-	(20.5)	(16.9)
15	Total	(325.4)	(73.5)	42.0	-	(356.9)	117.8	(239.1)	(229.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2018	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2018	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: K. Culbert

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2018	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2018	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.3)	(0.0)	-	-	(1.4)	-	(1.4)	(1.4)
2.	Total	(1.3)	(0.0)	-	-	(1.4)	-	(1.4)	(1.4)

Witness: K. Culbert

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.		Account Receivable Rebillable Projects	Materials and Supplies	Mortgages Receivable	Customer Security Deposits	Prepaid Expenses	Gas in Storage	Working Cash Allowance	Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.4	34.1	-	(65.6)	0.6	381.4	39.9	391.8
2.	January 31	1.4	34.2	-	(65.1)	0.7	227.6	39.9	238.7
3.	February	1.4	34.3	-	(64.3)	0.4	105.1	39.9	116.8
4.	March	1.4	34.4	-	(64.3)	0.5	36.8	39.9	48.7
5.	April	1.4	34.5	-	(64.2)	1.0	48.3	39.9	60.9
6.	May	1.4	34.5	-	(64.2)	0.9	116.4	39.9	128.9
7.	June	1.4	34.6	-	(64.1)	0.9	203.5	39.9	216.2
8.	July	1.3	34.7	-	(64.1)	0.8	299.5	39.9	312.1
9.	August	1.3	34.8	-	(64.1)	2.2	396.1	39.9	410.2
10.	September	1.3	34.9	-	(64.8)	1.7	481.3	39.9	494.3
11.	October	1.3	34.9	-	(65.2)	1.1	524.4	39.9	536.4
12.	November	1.3	35.0	-	(65.9)	0.7	495.5	39.9	506.5
13.	December	1.3	35.1	-	(65.1)	0.6	380.0	39.9	391.8
14.	Avg. of monthly avgs.	1.4	34.6	-	(64.6)	1.0	276.3	39.9	288.6

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2018 FORECAST YEAR

Line No.		Col. 1 Disbursements	Col. 2 Net Lag-Days	Col. 3 Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,647.2	8.8	39.7
2.	Items not subject to working cash allowance (Note 1)	(14.7)		
3.	Gas costs charged to operations	1,632.5		
4.	Operation and Maintenance	353.3		
5.	Less: Storage costs	(8.4)		
6.	Operation and maintenance costs subject to working cash	344.9		
7.	Ancillary customer services	-		
8.		344.9	(4.4)	(4.2)
9.	Sub-total			35.5
10.	Storage costs	8.4	64.9	1.5
11.	Storage municipal and capital taxes	1.4	29.4	0.1
12.	Sub-total			1.6
13.	Harmonized Sales Tax			2.8
14.	Total working cash allowance			39.9

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY OPERATING REVENUE
2017 FORECAST YEAR

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	2,480.3	(91.8)	2,388.5
2.	Transportation of gas	211.1	(18.4)	192.7
3.	Transmission, compression & storage	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,734.5	(110.2)	2,624.3

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(91.8)	Gas sales To remove Customer Care and CIS impacts embedded and approved in 2013 rates (EB-2011-0354).
2.	(18.4)	Transportation of gas To remove Customer Care and CIS impacts embedded and approved in 2013 rates (EB-2011-0354).

UTILITY REVENUE
2017 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Revenue ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Revenue ($Millions)
1.	Residential	1,545.8	-	1,545.8
2.	Commercial	793.5	-	793.5
3.	Industrial	109.8	-	109.8
4.	Wholesale	31.2	-	31.2
5.	Gas sales	2,480.3	-	2,480.3
6.	Transportation of gas	211.1	-	211.1
7.	Transmission, compression & storage	1.8	-	1.8
8.	Service charges & DPAC	12.3	-	12.3
9.	Rent from NGV rentals	1.1	-	1.1
10.	Late payment penalties	10.1	-	10.1
11.	Transactional services	13.4	(1.4)	12.0
12.	Open bill revenue	6.7	(1.3)	5.4
13.	Dow Moore recovery	0.3	-	0.3
14.	Affiliate asset use revenue	0.2	(0.2)	-
15.	ABC T-service (net)	1.1	(1.1)	-
16.	Other operating revenue	45.2	(4.0)	41.2
17.	Income from investments	-	-	-
18.	Interest during construction	7.4	(7.4)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	-	-	-
21.	Property/asset use revenue 3rd party	1.1	(1.1)	-
22.	Interest and property rental	8.5	(8.5)	-
23.	Miscellaneous	16.7	(16.6)	0.1
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	79.4	(79.3)	0.1
28.	Total revenue	2,826.3	(91.8)	2,734.5

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
11.	(1.4)	Transactional services To eliminate transactional services revenues above the proposed base amount to be included in rates. Ratepayer and shareholder amounts above the base will be treated outside of utility results and returns.
12.	(1.3)	Open bill revenue To eliminate the Open Bill shareholder incentive.
14.	(0.2)	Affiliate asset use revenue To reflect the elimination of asset use revenue in conjunction with the removal of affiliate use asset values from rate base and all related cost of service elements. (RP-2002-0133)
15.	(1.1)	ABC T-Service (net) To eliminate the net revenue from ABC T-Service considered to be non-utility. (RP-1999-0001)

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
18.	(7.4)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
21.	(1.1)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(16.6)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(11.2)
		To eliminate the shareholders' incentive income recorded as a result of calculating the DSMIVA amount.	(5.4)
			(16.6)
24.	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	

Witness: K. Culbert

COMPARISON OF UTILITY OPERATING REVENUE
2017 FORECAST AND 2016 FORECAST

Item No.		Col. 1 2017 Forecast ($Millions)	Col. 2 2016 Forecast ($Millions)	Col. 3 2017 Forecast Over/(Under) 2016 Forecast ($Millions)
1.1	Gas Sales	2,480.3	2,464.5	15.8
1.2	Transportation of Gas	211.1	217.1	(6.0)
1.3	Transmission, Compression and Storage	1.8	1.8	-
1.4	Other Revenue	41.3	41.3	(0.0)
1.1	Total Operating Revenue	2,734.5	2,724.7	9.8

Witnesses: R. Cheung
S. Qian

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2017 FORECAST

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)	
General Service					
1.1.1	Rate 1 - Sales	1 868 112	4 341.8	1 545.2	
1.1.2	Rate 1 - T-Service	135 997	366.9	67.0	
1.1	Total Rate 1	2 004 109	4 708.7	1 612.2	
1.2.1	Rate 6 - Sales	149 208	3 215.9	873.4	
1.2.2	Rate 6 - T-Service	14 745	1 443.7	106.4	
1.2	Total Rate 6	163 953	4 659.6	979.8	
1.3.1	Rate 9 - Sales	7	0.7	0.2	
1.3.2	Rate 9 - T-Service	1	0.1	0.0	**
1.3	Total Rate 9	8	0.8	0.2	
1.	Total General Service Sales & T-Service	2 168 070	9 369.1	2 592.2	
Contract Sales					
2.1	Rate 100	0	0.0	0.0	
2.2	Rate 110	33	92.9	18.6	
2.3	Rate 115	1	0.9	0.2	
2.4	Rate 135	1	1.2	0.2	
2.5	Rate 145	11	22.0	4.3	
2.6	Rate 170	5	37.3	6.5	
2.7	Rate 200	1	185.9	31.2	
2.	Total Contract Sales	52	340.2	61.0	
Contract T-Service					
3.1	Rate 100	0	0.0	0.0	
3.2	Rate 110	158	526.8	15.3	
3.3	Rate 115	26	470.7	6.4	
3.4	Rate 125	5	0.0 *	10.9	
3.5	Rate 135	40	55.3	1.7	
3.6	Rate 145	90	140.6	3.6	
3.7	Rate 170	29	415.7	(0.2)	
3.8	Rate 300	2	30.0	0.2	
3.9	Rate 315	0	0.0	0.0	
3.	Total Contract T-Service	350	1 639.1	37.9	
4.	Total Contract Sales & T-Service	402	1 979.3	98.9	
5.	Total	2 168 472	11 348.4	2 691.1	

* There is no distribution volume for Rate 125 customers.
** Less than $50,000.

Witnesses: R. Cheung
S. Qian

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2017 FORECAST AND 2016 FORECAST

		Col. 1	Col. 2	Col. 3
Item No.		2017 Forecast	2016 Forecast	2017 Forecast Over (Under) 2016 Forecast (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 868 112	1 815 636	52 476
1.1.2	Rate 1 - T-Service	135 997	153 324	(17 327)
1.1	Total Rate 1	2 004 109	1 968 960	35 149
1.2.1	Rate 6 - Sales	149 208	146 220	2 988
1.2.2	Rate 6 - T-Service	14 745	16 297	(1 552)
1.2	Total Rate 6	163 953	162 517	1 436
1.3.1	Rate 9 - Sales	7	7	0
1.3.2	Rate 9 - T-Service	1	1	0
1.3	Total Rate 9	8	8	0
1.	Total General Service Sales & T-Service	2 168 070	2 131 485	36 585
Contract Sales				
2.1	Rate 100	0	0	0
2.2	Rate 110	33	33	0
2.3	Rate 115	1	1	0
2.4	Rate 135	1	1	0
2.5	Rate 145	11	11	0
2.6	Rate 170	5	5	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	52	52	0
Contract T-Service				
3.1	Rate 100	0	0	0
3.2	Rate 110	158	158	0
3.3	Rate 115	26	26	0
3.4	Rate 125	5	5	0
3.5	Rate 135	40	40	0
3.6	Rate 145	90	90	0
3.7	Rate 170	29	29	0
3.8	Rate 300	2	2	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	350	350	0
4.	Total Contract Sales & T-Service	402	402	0
5.	Total	2 168 472	2 131 887	36 585

Witnesses: R. Cheung
S. Qian

UTILITY OPERATING REVENUE
2018 FORECAST YEAR

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	2,496.2	(91.8)	2,404.4
2.	Transportation of gas	205.0	(18.4)	186.6
3.	Transmission, compression & storage	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,744.3	(110.2)	2,634.1

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(91.8)	Gas sales To remove Customer Care and CIS impacts embedded and approved in 2013 rates (EB-2011-0354).
2.	(18.4)	Transportation of gas To remove Customer Care and CIS impacts embedded and approved in 2013 rates (EB-2011-0354).

UTILITY REVENUE
2018 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Revenue ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Revenue ($Millions)
1.	Residential	1,558.7	-	1,558.7
2.	Commercial	796.4	-	796.4
3.	Industrial	109.9	-	109.9
4.	Wholesale	31.2	-	31.2
5.	Gas sales	2,496.2	-	2,496.2
6.	Transportation of gas	205.0	-	205.0
7.	Transmission, compression & storage	1.8	-	1.8
8.	Service charges & DPAC	12.3	-	12.3
9.	Rent from NGV rentals	1.1	-	1.1
10.	Late payment penalties	10.1	-	10.1
11.	Transactional services	13.4	(1.4)	12.0
12.	Open bill revenue	6.7	(1.3)	5.4
13.	Dow Moore recovery	0.3	-	0.3
14.	Affiliate asset use revenue	0.2	(0.2)	-
15.	ABC T-service (net)	1.1	(1.1)	-
16.	Other operating revenue	45.2	(4.0)	41.2
17.	Income from investments	-	-	-
18.	Interest during construction	7.4	(7.4)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	-	-	-
21.	Property/asset use revenue 3rd party	1.1	(1.1)	-
22.	Interest and property rental	8.5	(8.5)	-
23.	Miscellaneous	16.7	(16.6)	0.1
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	79.4	(79.3)	0.1
28.	Total revenue	2,836.1	(91.8)	2,744.3

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
11.	(1.4)	Transactional services To eliminate transactional services revenues above the proposed base amount to be included in rates. Ratepayer and shareholder amounts above the base will be treated outside of utility results and returns.
12.	(1.3)	Open bill revenue To eliminate the Open Bill shareholder incentive.
14.	(0.2)	Affiliate asset use revenue To reflect the elimination of asset use revenue in conjunction with the removal of affiliate use asset values from rate base and all related cost of service elements. (RP-2002-0133)
15.	(1.1)	ABC T-Service (net) To eliminate the net revenue from ABC T-Service considered to be non-utility. (RP-1999-0001)

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
18.	(7.4)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
21.	(1.1)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(16.6)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(11.2)
		To eliminate the shareholders' incentive income recorded as a result of calculating the DSMIVA amount.	(5.4)
			(16.6)
24.	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	

COMPARISON OF UTILITY OPERATING REVENUE
2018 FORECAST AND 2017 FORECAST

		Col. 1	Col. 2	Col. 3
Item No.		2018 Forecast	2017 Forecast	2018 Forecast Over/(Under) 2017 Forecast
		($Millions)	($Millions)	($Millions)
1.1	Gas Sales	2,496.2	2,480.3	15.9
1.2	Transportation of Gas	205.0	211.1	(6.1)
1.3	Transmission, Compression and Storage	1.8	1.8	-
1.4	Other Revenue	41.3	41.3	(0.0)
1.1	Total Operating Revenue	2,744.3	2,734.5	9.8

Witness: R. Cheung
S. Qian

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2018 FORECAST

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)	
General Service					
1.1.1	Rate 1 - Sales	1 920 588	4 341.8	1 558.1	
1.1.2	Rate 1 - T-Service	118 669	366.9	62.7	
1.1	Total Rate 1	2 039 257	4 708.7	1 620.8	
1.2.1	Rate 6 - Sales	152 195	3 215.9	876.3	
1.2.2	Rate 6 - T-Service	13 194	1 443.7	104.6	
1.2	Total Rate 6	165 389	4 659.6	980.9	
1.3.1	Rate 9 - Sales	7	0.7	0.2	
1.3.2	Rate 9 - T-Service	1	0.1	0.0	**
1.3	Total Rate 9	8	0.8	0.2	
1.	Total General Service Sales & T-Service	2 204 654	9 369.1	2 601.9	
Contract Sales					
2.1	Rate 100	0	0.0	0.0	
2.2	Rate 110	33	92.9	18.6	
2.3	Rate 115	1	0.9	0.2	
2.4	Rate 135	1	1.2	0.2	
2.5	Rate 145	11	22.0	4.3	
2.6	Rate 170	5	37.3	6.5	
2.7	Rate 200	1	185.9	31.2	
2.	Total Contract Sales	52	340.2	61.0	
Contract T-Service					
3.1	Rate 100	0	0.0	0.0	
3.2	Rate 110	158	526.8	15.3	
3.3	Rate 115	26	470.7	6.4	
3.4	Rate 125	5	0.0 *	10.9	
3.5	Rate 135	40	55.3	1.7	
3.6	Rate 145	90	140.6	3.6	
3.7	Rate 170	29	415.7	(0.2)	
3.8	Rate 300	2	30.0	0.2	
3.9	Rate 315	0	0.0	0.0	
3.	Total Contract T-Service	350	1 639.1	37.9	
4.	Total Contract Sales & T-Service	402	1 979.3	98.9	
5.	Total	2 205 056	11 348.4	2 700.8	

* There is no distribution volume for Rate 125 customers.
** Less than $50,000.

Witnesses: R. Cheung
S. Qian

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2018 FORECAST AND 2017 FORECAST

Item No.		Col. 1 2018 Forecast	Col. 2 2017 Forecast	Col. 3 2018 Forecast Over (Under) 2017 Forecast (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 920 588	1 868 112	52 476
1.1.2	Rate 1 - T-Service	118 669	135 997	(17 328)
1.1	Total Rate 1	2 039 257	2 004 109	35 148
1.2.1	Rate 6 - Sales	152 195	149 208	2 987
1.2.2	Rate 6 - T-Service	13 194	14 745	(1 551)
1.2	Total Rate 6	165 389	163 953	1 436
1.3.1	Rate 9 - Sales	7	7	0
1.3.2	Rate 9 - T-Service	1	1	0
1.3	Total Rate 9	8	8	0
1.	Total General Service Sales & T-Service	2 204 654	2 168 070	36 584
Contract Sales				
2.1	Rate 100	0	0	0
2.2	Rate 110	33	33	0
2.3	Rate 115	1	1	0
2.4	Rate 135	1	1	0
2.5	Rate 145	11	11	0
2.6	Rate 170	5	5	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	52	52	0
Contract T-Service				
3.1	Rate 100	0	0	0
3.2	Rate 110	158	158	0
3.3	Rate 115	26	26	0
3.4	Rate 125	5	5	0
3.5	Rate 135	40	40	0
3.6	Rate 145	90	90	0
3.7	Rate 170	29	29	0
3.8	Rate 300	2	2	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	350	350	0
4.	Total Contract Sales & T-Service	402	402	0
5.	Total	2 205 056	2 168 472	36 584

Witnesses: R. Cheung
S. Qian

RELOCATION & REPLACEMENT MAINS VARIANCE ACCOUNTS

1. As indicated in updated evidence filed at Exhibit A2, Tab 1, Schedules 1 and 3, and Exhibit B2, Tab 1, Schedule 1, EGD has updated its Customized IR plan to allow for the approval of the 2017 and 2018 Allowed Revenue within this proceeding, and is no longer requesting an update or capital refresh for 2017 and 2018 midway through the 2014-2018 Customized IR term. As explained, EGD proposes that the 2017 and 2018 estimated rate base and related Allowed Revenue amounts previously filed as preliminary values at Exhibit F1, Tab1, Schedule 3 are now to be used as final values. Supporting evidence is filed at Exhibits F6 and F7.

2. As indicated in the Updated Capital Budget Overview evidence (Exhibit B2, Tab 1, Schedule 1, at paragraphs 114 to 116), EGD is also proposing two new variance accounts for 2017 and 2018 only, to deal with two specific elements of its capital spending requirements, relocation and miscellaneous replacement mains. As explained in the above-noted evidence, relocations costs are difficult to forecast and are beyond the Company's control because they arise from the activities of third parties. Costs related to replacement mains requirements identified through pipeline inspection activities such as (but not limited to) In Line Inspection ("ILI") and Maximum Operating Pressure ("MOP") programs are not included within the Company's Capital Budgets, although there is an amount included for "Miscellaneous Main Replacements". While Enbridge has indicated that it will take the risk of such costs for 2014 to 2016, the Company believes it appropriate to have variance account protection for such costs during 2017 and 2018.

3. The proposed variance account treatment is the same for both relocation and replacement mains, however, separate accounts named Relocation Mains Variance

Account (“RLMVA”) and Replacement Mains Variance Account (“RPMVA”) will be established where appropriate for each of 2017 and 2018.

4. EGD believes that it is appropriate to use the same financial eligibility thresholds for these new accounts as exist for Z Factors. Therefore, in order for one of the variance accounts to be operative, there must be a variance of at least $1.5 million from the cumulative revenue requirement associated with relocations or replacement mains for the subject year. If this threshold is met, then the total revenue requirement for the year in which the threshold is met is to be recorded and recoverable in the variance account for that year.

5. The Company proposes that the cumulative revenue requirement for each account for each year is to be determined in the following manner.

6. For the RLMVA, the actual capital spend amounts for relocations activities will be tracked by month for each year (2017 and 2018).

7. The amount to be recorded within the 2017 RLMVA will be determined as follows:

    a. If the spending for relocations activities in 2017 is more than the $12.6 million forecast, then EGD will eliminate the first $12.6 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $12.6 million (which is the forecast capital cost for relocations in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, p. 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year and if the resulting revenue requirement amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RLMVA for future recovery by Enbridge.

b. If the spending for relocations activities in 2017 is less than the $12.6 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent. If the resulting amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RLMVA for future credit to ratepayers.

8. The amount to be recorded within the 2018 RLMVA will be determined as follows

a. First, an amount (which may be positive or negative) related to the 2017 capital spending on relocations will be determined. That will be done by taking the difference (positive) or negative between actual capital spending and $12.6 million, and then determining the revenue requirement implications of that amount in 2018.

b. Second, the relevant revenue requirement amount related to 2018 capital spending on relocations will be added to the number determined in (a).

(i) If the spending for relocations activities in 2018 is more than the $12.6 million forecast, then EGD will eliminate the first $12.6 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $12.6 million (which is the forecast capital cost for relocations in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, p. 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year.

(ii) If the spending for relocations activities in 2018 is less than the \$12.6 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent.

c. If the sum of the amounts calculated under (a) and (b) above is more than \$1.5 million (positive or negative), then that amount will be recorded in the 2018 RLMVA for future recovery.

9. For the RPMVA, the actual spend amounts for miscellaneous mains replacement activities, including those identified through pipeline inspection activities (such as, but not limited to ILI and MOP programs) will be tracked by month for each year.

10. The amount to be recorded within the 2017 RPMVA will be determined as follows:

a. If the spending for miscellaneous main replacement activities in 2017 is more than the \$5.1 million forecast, then EGD will eliminate the first \$5.1 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the \$5.1 million (which is the forecast capital cost for miscellaneous main replacement activities in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, p. 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year and if the resulting revenue requirement amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RPMVA for future recovery by EGD.

b. If the spending for miscellaneous main replacement activities in 2017 is less than the $5.1 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent. If the resulting amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RPMVA for future credit to ratepayers.

11. The amount to be recorded within the 2018 RPMVA will be determined as follows

a. First, an amount (which may be positive or negative) related to the 2017 capital spending on miscellaneous main replacement activities will be determined. That will be done by taking the difference (positive) or negative between actual capital spending and $5.1 million, and then determining the revenue requirement implications of that amount in 2018.

b. Second, the relevant revenue requirement amount related to 2018 capital spending on relocations will be added to the number determined in (a).

(i) If the spending for miscellaneous main replacement activities in 2018 is more than the $5.1 million forecast, then EGD will eliminate the first $5.1 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $5.1 million (which is the forecast capital cost for miscellaneous main replacement activities in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, page 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year.

(ii) If the spending for miscellaneous main replacement activities in 2018 is less than the $5.1 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent.

c. If the sum of the amounts calculated under (a) and (b) above is more than $1.5 million (positive or negative), then that amount will be recorded in the 2018 RPMVA for future recovery.

COST OF SERVICE
2017 FORECAST YEAR

Line No.		Col. 1 Utility Costs and Expenses	Col. 2 Normalizing and Other Adjustments	Col. 3 Adjusted Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	450.5	(104.4)	346.1
3.	Depreciation and amortization expense	313.4	(12.7)	300.7
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	47.9	-	47.9
6.	Operating costs	2,446.2	(117.1)	2,329.1
7.	Income tax expense			1.3
8.	Cost of service			2,330.4

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
2.	(104.4)	Operation and Maintenance
		To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.
3.	(12.7)	Depreciation and Amortization Expense
		To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	295.2	295.2	
	Add			
2.	Depreciation and amortization	300.7	300.7	
3.	Accrual based pension and OPEB costs	28.5	28.5	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	330.2	330.2	
6.	Sub-total	625.4	625.4	
	Deduct			
7.	Capital cost allowance	293.2	293.2	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.6	5.6	
10.	Amortization of share/debenture issue expense	3.9	3.9	
11.	Amortization of cumulative eligible capital	4.3	4.3	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site Rest Costs adjustment	53.1	53.1	
14.	Cash based pension and OPEB costs	32.2	32.2	
15.	Total Deduction	439.0	439.0	
16.	Taxable income	186.4	186.4	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	28.0	21.4	49.4
19.	Part VI.1 tax			1.9
20.	Total taxes excluding interest shield			51.3
	Tax shield on interest expense			
21.	Rate base	5,716.9		
22.	Return component of debt	3.30%		
23.	Interest expense	188.5		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(50.0)
26.	Total utility income taxes			1.3

Witness: K. Culbert

COST OF SERVICE
2017 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	463.0	(12.5)	450.5
3.	Depreciation	312.6	(0.8)	311.8
4.	Amortization	1.6	-	1.6
5.	Depreciation and amortization	314.2	(0.8)	313.4
6.	Fixed financing costs	1.9	-	1.9
7.	Municipal and other taxes	48.1	(0.2)	47.9
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	48.1	(0.2)	47.9
10.	Interest on long-term debt	176.0	(176.0)	-
11.	Amortization of preference share issue costs and debt discount and expense	3.5	(3.5)	-
				-
12.	Interest and financing amortization	179.5	(179.5)	-
13.	Interest on short-term debt	22.2	(22.2)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	49.0	(49.0)	-
16.	Total operating costs	2,688.2	(242.0)	2,446.2
17.	Current taxes	(10.8)	10.8	-
18.	Deferred taxes	0.7	(0.7)	-
19.	Income tax expense	(10.1)	10.1	-
20.	Cost of service	2,678.1	(231.9)	2,446.2

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(12.5)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	2.6
		To eliminate donations (EBRO 490).	(0.8)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.8)
		To eliminate Corporate Cost allocations above RCAM amount.	(12.5)
			(12.5)
3.	(0.8)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
			(0.8)
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(176.0)	Interest on long-term debt Expense of capital.
13.	(3.5)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(22.2)	Interest on short-term debt Expense of capital.
16.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	10.8	Income taxes - current Income tax expense related to corporate earnings.
20.	(0.7)	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2017 FORECAST YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2017	UCC Carry Forward
1	1,581,943,554	-	-	-	4.00%	(63,277,742)	1,518,665,812
51	2,572,985,662	347,950,400	-	173,975,200	6.00%	(164,817,652)	2,756,118,411
2	93,316,592	-	(337,655)	(168,828)	6.00%	(5,588,866)	87,390,071
6	8,955	-	-	-	10.00%	(896)	8,060
8	23,955,695	8,073,000	-	4,036,500	20.00%	(5,598,439)	26,430,256
10	15,379,069	5,739,031	(420,613)	2,659,209	30.00%	(5,411,483)	15,286,004
12	15,576,294	19,300,000	-	9,650,000	100.00%	(25,226,294)	9,650,000
12	-	-	-	-	-	-	-
17	23,199	-	-	-	8.00%	(1,856)	21,343
38	3,431,432	1,331,250	(67,100)	632,075	30.00%	(1,219,052)	3,476,530
41	45,935,835	7,813,842	-	3,906,921	25.00%	(12,460,689)	41,288,988
13	16,557,431	270,000	-	135,000	-	(249,000)	16,578,431
3	192,809	-	-	-	5.00%	(9,641)	183,169
45	44,815	-	-	-	45.00%	(20,167)	24,648
50	14,277,151	8,200,000	-	4,100,000	55.00%	(10,107,433)	12,369,718
52	-	-	-	-	100.00%	-	-
Total	4,383,628,494	398,677,523	(825,368)	198,926,078		(293,989,209)	4,487,491,440

Non-utility and shared asset eliminations	758,942
Utility Federal CCA	(293,230,267)

Capital Cost Allowance - Ontario

Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2017	UCC Carry Forward
1	1,581,943,554	-	-	-	4.00%	(63,277,742)	1,518,665,812
51	2,572,985,662	347,950,400	-	173,975,200	6.00%	(164,817,652)	2,756,118,411
2	93,316,592	-	(337,655)	(168,828)	6.00%	(5,588,866)	87,390,071
6	8,955	-	-	-	10.00%	(896)	8,060
8	23,955,695	8,073,000	-	4,036,500	20.00%	(5,598,439)	26,430,256
10	15,379,069	5,739,031	(420,613)	2,659,209	30.00%	(5,411,483)	15,286,004
12	15,576,294	19,300,000	-	9,650,000	100.00%	(25,226,294)	9,650,000
12	-	-	-	-	-	-	-
17	23,199	-	-	-	8.00%	(1,856)	21,343
38	3,431,432	1,331,250	(67,100)	632,075	30.00%	(1,219,052)	3,476,530
41	45,935,835	7,813,842	-	3,906,921	25.00%	(12,460,689)	41,288,988
13	16,557,431	270,000	-	135,000	-	(249,000)	16,578,431
3	192,809	-	-	-	5.00%	(9,640)	183,169
45	44,815	-	-	-	45.00%	(20,167)	24,648
50	14,277,151	8,200,000	-	4,100,000	55.00%	(10,107,433)	12,369,718
52	-	-	-	-	100.00%	-	-
Total	4,383,628,494	398,677,523	(825,368)	198,926,078		(293,989,209)	4,487,491,440

Non-utility and shared asset eliminations	758,942
Utility Provincial CCA and UCC	(293,230,267)

COST COMPARISON OF UTILITY
OPERATING COSTS AND EXPENSES
2017 FORECAST AND 2016 FORECAST

		Col. 1	Col. 2	Col. 3
Item No.		2017 Forecast ($Millions)	2016 Forecast ($Millions)	2017 Forecast Over/(Under) 2016 Forecast ($Millions)
1.1	Gas costs charged to operations	1,632.5	1,632.5	-
1.2	Operations and maintenance	450.5	439.5	11.0
1.3	Depreciation	313.4	303.9	9.5
1.4	Fixed financing costs	1.9	1.9	-
1.5	Municipal and other taxes	47.9	45.5	2.4
1.0	Total costs and expenses	2,446.2	2,423.3	22.9

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2017 FORECAST AND 2016 FORECAST

Item No.

1.1 Gas costs charged to operations – immaterial change

1.2 Operation and maintenance - increase of $11.0 Million

The increase in operation and maintenance costs in the 2017 Forecast from 2016 forecast is primarily due to applying average annual growth rate for the “Other O&M” and RCAM costs from 2013 to 2016 and the inflationary pressures for the 2016 DSM forecast.

1.3 Depreciation expense – increase of $9.5 Million

The increase in depreciation expense is mainly due to higher depreciable PP&E resulting from the annual capital expenditures.

1.4 Fixed financing costs – immaterial change

1.5 Municipal and other taxes – increase of $2.4 Million

The increase reflects the average rate of change on municipal tax rate.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2017 Forecast Year

Line No.	Particulars ($ 000's)	Budget 2017
1.	Operations	$ 70,947
2.	Pipeline Integrity & Engineering	42,047
3.	Human Resources and Facilities	23,687
4.	Employee Benefits	27,765
5.	Short Term Incentive Program	22,806
6.	Information Technology	32,668
7.	Regulatory, Public and Government Affairs	21,914
8.	Finance	12,631
9.	Provision for Uncollectibles (Bad Debts)	9,796
10.	Customer Care (Exclude CC/CIS and Bad Debts)	2,526
11.	Business Development & Customer Strategy (excluding DSM)	6,709
12.	Legal and Corporate Security	5,662
13.	Energy Supply and Policy	4,588
14.	Non-Departmental	3,869
15.	Capitalization (A&G)	(38,299)
16.	Interest on Security Deposit	2,599
17.	Regulatory Eliminations	(3,398)
18.	Other O&M	248,518
19.	Customer Care/CIS Service Charges	104,400
20.	Pensions and OPEB Costs	28,500
20.	Corporate Cost Allocations (including direct costs)	44,650
21.	Demand Side Management Programs (DSM)	34,200
22.	Subtotal	460,268
	Other Regulatory Eliminations	
23.	To eliminate Corporate Cost Allocations above RCAM	(9,818)
24.	Total Eliminations	(9,818)
25.	Total Net Utility O&M Expense	$ 450,450

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2017 Forecast Year vs. 2013 Board Approved

Line No.	Particulars ($000's)	Budget 2017 (a)	Board Approved 2013 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$ 183,113	$ 166,355	$ 16,758	10.1%
2.	Benefits	27,765	25,261	2,505	9.9%
3.	Short Term Incentive Program	22,806	20,700	2,106	10.2%
4.	Employee Training and Development	4,964	4,751	214	4.5%
5.	Materials and Supplies	5,495	5,309	186	3.5%
6.	Outside Services	94,020	83,710	10,310	12.3%
7.	Consulting	5,322	5,082	240	4.7%
8.	Repairs and Maintenance	2,522	2,343	179	7.6%
9.	Fleet	11,011	10,213	799	7.8%
10.	Rents and Leases	8,055	7,338	717	9.8%
11.	Telecommunications	4,034	3,637	397	10.9%
12.	Travel and Other Business Expenses	5,286	5,387	(101)	-1.9%
13.	Memberships	5,411	5,010	401	8.0%
14.	Claims, Damages and Legal Fees	1,004	863	142	16.4%
15.	Interest on Security Deposits	2,599	780	1,819	233.3%
16.	Provision for Uncollectibles	9,796	9,500	296	3.1%
17.	Legal Fees	2,975	2,700	275	10.2%
18.	Audit Fees	1,723	1,594	129	8.1%
19.	Other	5,146	4,545	601	13.2%
20.	Internal Allocations and Recoveries	(31,086)	(29,900)	(1,186)	4.0%
21.	Capitalization (A&G)	(38,299)	(37,795)	(503)	1.3%
22.	Capitalization	(81,748)	(74,136)	(7,612)	10.3%
23.	Regulatory Eliminations	(3,398)	(4,049)	652	-16.1%
24.	Other O&M	248,518	219,197	29,321	13.4%
25.	Customer Care/CIS Service Charges	104,400	89,444	14,956	16.7%
26.	Pension and OPEB Costs	28,500	42,800	(14,300)	-33.4%
27.	Corporate Cost Allocations (including direct costs)	44,650	45,761	(1,111)	-2.4%
28.	Demand Side Management Programs (DSM)	34,200	31,588	2,612	8.3%
29.	Conservation Services	-	2,728	(2,728)	-100.0%
30.	Subtotal	460,268	431,519	28,749	6.7%
	Other Regulatory Eliminations				
31.	To eliminate Corporate Cost Allocations above RCAM	(9,818)	(13,666)	3,848	-28.2%
32.	To eliminate Conservation Services	-	(2,728)	2,728	-100.0%
33.	Total Eliminations	(9,818)	(16,394)	6,576	-40.1%
34.	Total Net Utility O&M Expense	$ 450,450	$ 415,125	$ 35,325	8.5%
35.	FTE's	2,361	2,388	-27	-1.1%

Witnesses: S. Kancharla
R. Lei

FTE and SALARIES & WAGES
2017 Budget Year

	Col. 1	Col. 2	Col. 3
Salary Bands	FTE	Total Salaries ($000's)	Average Salary ($000's)
1. Management	152	$ 25,204	$ 165.8
2. Supervisory	1,470	128,038	87.1
3. Unionized	739	49,848	67.5
4. Total	2,361	$ 203,089	$ 86.0

Witnesses: S. Kancharla
R. Lei
S. Trozzi

COST OF SERVICE
2018 FORECAST YEAR

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	461.8	(108.5)	353.3
3.	Depreciation and amortization expense	322.1	(12.7)	309.4
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	50.4	-	50.4
6.	Operating costs	2,468.7	(121.2)	2,347.5
7.	Income tax expense			8.7
8.	Cost of service			2,356.2

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
2.	(108.5)	Operation and Maintenance To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.
3.	(12.7)	Depreciation and Amortization Expense To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	286.6	286.6	
	Add			
2.	Depreciation and amortization	309.4	309.4	
3.	Accrual based pension and OPEB costs	26.2	26.2	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	336.6	336.6	
6.	Sub-total	623.2	623.2	
	Deduct			
7.	Capital cost allowance	293.8	293.8	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.6	5.6	
10.	Amortization of share/debenture issue expense	4.0	4.0	
11.	Amortization of cumulative eligible capital	4.0	4.0	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site Rest Costs adjustment	17.4	17.4	
14.	Cash based pension and OPEB costs	29.8	29.8	
15.	Total Deduction	401.3	401.3	
16.	Taxable income	221.9	221.9	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	33.3	25.5	58.8
19.	Part VI.1 tax			1.9
20.	Total taxes excluding interest shield			60.7
	Tax shield on interest expense			
21.	Rate base	5,899.1		
22.	Return component of debt	3.33%		
23.	Interest expense	196.4		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(52.0)
26.	Total utility income taxes			8.7

COST OF SERVICE
2018 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	474.7	(12.9)	461.8
3.	Depreciation	321.3	(0.8)	320.5
4.	Amortization	1.6	-	1.6
5.	Depreciation and amortization	322.9	(0.8)	322.1
6.	Fixed financing costs	1.9	-	1.9
7.	Municipal and other taxes	50.6	(0.2)	50.4
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	50.6	(0.2)	50.4
10.	Interest on long-term debt	176.0	(176.0)	-
11.	Amortization of preference share issue costs and debt discount and expense	3.5	(3.5)	-
				-
12.	Interest and financing amortization	179.5	(179.5)	-
13.	Interest on short-term debt	22.2	(22.2)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	49.0	(49.0)	-
16.	Total operating costs	2,711.1	(242.4)	2,468.7
17.	Current taxes	(10.8)	10.8	-
18.	Deferred taxes	0.7	(0.7)	-
19.	Income tax expense	(10.1)	10.1	-
20.	Cost of service	2,701.0	(232.3)	2,468.7

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(12.9)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	2.7
		To eliminate donations (EBRO 490).	(0.9)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.8)
		To eliminate Corporate Cost allocations above RCAM amount.	(12.9)
			(12.9)
3.	(0.8)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
			(0.8)
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(176.0)	Interest on long-term debt Expense of capital.
13.	(3.5)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(22.2)	Interest on short-term debt Expense of capital.
16.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	10.8	Income taxes - current Income tax expense related to corporate earnings.
20.	(0.7)	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2018 FORECAST YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2017	UCC Carry Forward
1	1,518,665,812	-	-	-	4.00%	(60,746,633)	1,457,919,179
51	2,756,118,411	352,699,649	-	176,349,825	6.00%	(175,948,094)	2,932,869,966
2	87,390,071	-	(337,655)	(168,828)	6.00%	(5,233,275)	81,819,141
6	8,060	-	-	-	10.00%	(806)	7,254
8	26,430,256	8,073,000	-	4,036,500	20.00%	(6,093,351)	28,409,905
10	15,286,004	5,739,031	(420,613)	2,659,209	30.00%	(5,383,564)	15,220,858
12	9,650,000	19,300,000	-	9,650,000	100.00%	(19,300,000)	9,650,000
12	-	-	-	-	-	-	-
17	21,343	-	-	-	8.00%	(1,708)	19,636
38	3,476,530	1,331,250	(67,100)	632,075	30.00%	(1,232,582)	3,508,098
41	41,288,988	7,813,842	-	3,906,921	25.00%	(11,298,977)	37,803,853
13	16,578,431	270,000	-	135,000	-	(249,000)	16,599,431
3	183,169	-	-	-	5.00%	(9,158)	174,010
45	24,648	-	-	-	45.00%	(11,092)	13,557
50	12,369,718	8,200,000	-	4,100,000	55.00%	(9,058,345)	11,511,373
52	-	-	-	-	100.00%	-	-
Total	4,487,491,440	403,426,772	(825,368)	201,300,702		(294,566,584)	4,595,526,260

Non-utility and shared asset eliminations	756,512
Utility Federal CCA	(293,810,072)

Capital Cost Allowance - Ontario

Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2017	UCC Carry Forward
1	1,518,665,812	-	-	-	4.00%	(60,746,633)	1,457,919,179
51	2,756,118,411	352,699,649	-	176,349,825	6.00%	(175,948,094)	2,932,869,966
2	87,390,071	-	(337,655)	(168,828)	6.00%	(5,233,275)	81,819,141
6	8,060	-	-	-	10.00%	(806)	7,254
8	26,430,256	8,073,000	-	4,036,500	20.00%	(6,093,351)	28,409,905
10	15,286,004	5,739,031	(420,613)	2,659,209	30.00%	(5,383,564)	15,220,858
12	9,650,000	19,300,000	-	9,650,000	100.00%	(19,300,000)	9,650,000
12	-	-	-	-	-	-	-
17	21,343	-	-	-	8.00%	(1,708)	19,636
38	3,476,530	1,331,250	(67,100)	632,075	30.00%	(1,232,582)	3,508,098
41	41,288,988	7,813,842	-	3,906,921	25.00%	(11,298,977)	37,803,853
13	16,578,431	270,000	-	135,000	-	(249,000)	16,599,431
3	183,169	-	-	-	5.00%	(9,158)	174,010
45	24,648	-	-	-	45.00%	(11,092)	13,557
50	12,369,718	8,200,000	-	4,100,000	55.00%	(9,058,345)	11,511,373
52	-	-	-	-	100.00%	-	-
Total	4,487,491,440	403,426,772	(825,368)	201,300,702		(294,566,584)	4,595,526,260

Non-utility and shared asset eliminations	756,512
Utility Provincial CCA and UCC	(293,810,072)

COST COMPARISON OF UTILITY
OPERATING COSTS AND EXPENSES
2018 FORECAST AND 2017 FORECAST

Item No.		Col. 1 2018 Forecast ($Millions)	Col. 2 2017 Forecast ($Millions)	Col. 3 2018 Forecast Over/(Under) 2017 Forecast ($Millions)
1.1	Gas costs charged to operations	1,632.5	1,632.5	-
1.2	Operations and maintenance	461.8	450.5	11.3
1.3	Depreciation	322.1	313.4	8.7
1.4	Fixed financing costs	1.9	1.9	-
1.5	Municipal and other taxes	50.4	47.9	2.5
1.0	Total costs and expenses	2,468.7	2,446.2	22.5

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2018 FORECAST AND 2017 FORECAST

Item No.

1.1 Gas costs charged to operations – immaterial change

1.2 Operation and maintenance - increase of $11.3 Million

The increase in operation and maintenance costs in the 2018 Forecast from 2017 forecast is primarily due to applying average annual growth rate for the "Other O&M" and RCAM costs from 2013 to 2016 and the inflationary pressures for the 2017 DSM forecast.

1.3 Depreciation expense – increase of $8.7 Million

The increase in depreciation expense is mainly due to higher depreciable PP&E resulting from the annual capital expenditures.

1.4 Fixed financing costs – immaterial change

1.5 Municipal and other taxes – increase of $2.5 Million

The increase reflects the average rate of change on municipal tax rate.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2018 Forecast Year

Line No.	Particulars ($ 000's)	Budget 2018
1.	Operations	$ 73,160
2.	Pipeline Integrity & Engineering	43,359
3.	Human Resources and Facilities	24,426
4.	Employee Benefits	28,632
5.	Short Term Incentive Program	23,518
6.	Information Technology	33,688
7.	Regulatory, Public and Government Affairs	22,598
8.	Finance	13,025
9.	Provision for Uncollectibles (Bad Debts)	10,102
10.	Customer Care (Exclude CC/CIS and Bad Debts)	2,604
11.	Business Development & Customer Strategy (excluding DSM)	6,919
12.	Legal and Corporate Security	5,839
13.	Energy Supply and Policy	4,731
14.	Non-Departmental	3,989
15.	Capitalization (A&G)	(39,494)
16.	Interest on Security Deposit	2,681
17.	Regulatory Eliminations	(3,504)
18.	Other O&M	256,272
19.	Customer Care/CIS Service Charges	108,500
20.	Pensions and OPEB Costs	26,200
20.	Corporate Cost Allocations (including direct costs)	46,043
21.	Demand Side Management Programs (DSM)	34,900
22.	Subtotal	471,915
	Other Regulatory Eliminations	
23.	To eliminate Corporate Cost Allocations above RCAM	(10,151)
24.	Total Eliminations	(10,151)
25.	Total Net Utility O&M Expense	$ 461,764

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2018 Forecast Year vs. 2013 Board Approved

Line No.	Particulars ($000's)	Budget 2018 (a)	Board Approved 2013 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$188,826	$ 166,355	$ 22,472	13.5%
2.	Benefits	28,632	25,261	3,371	13.3%
3.	Short Term Incentive Program	23,518	20,700	2,817	13.6%
4.	Employee Training and Development	5,119	4,751	368	7.8%
5.	Materials and Supplies	5,666	5,309	357	6.7%
6.	Outside Services	96,953	83,710	13,244	15.8%
7.	Consulting	5,488	5,082	406	8.0%
8.	Repairs and Maintenance	2,600	2,343	257	11.0%
9.	Fleet	11,355	10,213	1,142	11.2%
10.	Rents and Leases	8,306	7,338	968	13.2%
11.	Telecommunications	4,160	3,637	523	14.4%
12.	Travel and Other Business Expenses	5,451	5,387	64	1.2%
13.	Memberships	5,579	5,010	570	11.4%
14.	Claims, Damages and Legal Fees	1,036	863	173	20.1%
15.	Interest on Security Deposits	2,681	780	1,901	243.7%
16.	Provision for Uncollectibles	10,102	9,500	602	6.3%
17.	Legal Fees	3,068	2,700	368	13.6%
18.	Audit Fees	1,777	1,594	183	11.5%
19.	Other	5,307	4,545	762	16.8%
20.	Internal Allocations and Recoveries	(32,056)	(29,900)	(2,155)	7.2%
21.	Capitalization (A&G)	(39,494)	(37,795)	(1,698)	4.5%
22.	Capitalization	(84,299)	(74,136)	(10,163)	13.7%
23.	Regulatory Eliminations	(3,504)	(4,049)	546	-13.5%
24.	Other O&M	256,272	219,197	37,075	16.9%
25.	Customer Care/CIS Service Charges	108,500	89,444	19,056	21.3%
26.	Pension and OPEB Costs	26,200	42,800	(16,600)	-38.8%
27.	Corporate Cost Allocations (including direct costs)	46,043	45,761	282	0.6%
28.	Demand Side Management Programs (DSM)	34,900	31,588	3,312	10.5%
29.	Conservation Services	-	2,728	(2,728)	-100.0%
30.	Subtotal	471,915	431,519	40,396	9.4%
	Other Regulatory Eliminations				
31.	To eliminate Corporate Cost Allocations above RCAM	(10,151)	(13,666)	3,515	-25.7%
32.	To eliminate Conservation Services	-	(2,728)	2,728	-100.0%
33.	Total Eliminations	(10,151)	(16,394)	6,243	-38.1%
34.	Total Net Utility O&M Expense	$461,764	$ 415,125	$ 46,639	11.2%
35.	FTE's	2,361	2,388	-27	-1.1%

Witnesses: S. Kancharla
R. Lei

FTE and SALARIES & WAGES
2018 Budget Year

Salary Bands	Col. 1 FTE	Col. 2 Total Salaries ($000's)	Col. 3 Average Salary ($000's)
1. Management	152	$ 25,990	$ 171.0
2. Supervisory	1,470	132,033	89.8
3. Unionized	739	51,403	69.6
4. Total	2,361	$ 209,426	$ 88.7

Witnesses: S. Kancharla
R. Lei
S. Trozzi

COST OF CAPITAL
2017 FORECAST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,515.5	61.49	5.31	3.265
2.	Short-Term Debt	43.3	0.76	4.30	0.033
3.		3,558.8	62.25		3.298
4.	Preference Shares	100.0	1.75	4.64	0.081
5.	Common Equity	2,058.1	36.00	10.17	3.661
6.		5,716.9	100.00		7.040
7.	Rate Base	($Millions)			5,716.9
8.	Utility Income	($Millions)			293.9
9.	Indicated Rate of Return				5.141
10.	Deficiency in Rate of Return				(1.899)
11.	Net Deficiency	($Millions)			(108.6)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(147.7)
13.	Customer Care/CIS Deficiency	($Millions)	($128.6 vs $110.2)		(18.4)
14.	Total Gross Revenue Deficiency	($Millions)			(166.1)
15.	Revenue at Existing Rates	($Millions)			2,693.2
16.	Allowed Revenue	($Millions)			2,859.3
17.	Gross Revenue Deficiency	($Millions)			(166.1)
	Common Equity				
18.	Allowed Rate of Return				10.170
19.	Earnings on Common Equity				4.894
20.	Deficiency in Common Equity Return				(5.276)

Witness: K. Culbert

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2017 FORECAST YEAR

Line No.		Col. 1 Average of Monthly Averages	Col. 2	Col. 3 Carrying Cost
		($Millions)		($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	3,532.4		187.5
2.	Unamortized Finance Costs	(16.9)		-
3.	(Profit)/Loss on Redemption	-		-
4.		3,515.5		187.5
5.	Calculated Cost Rate		5.31%	
	Short-Term Debt			
6.	Calculated Cost Rate		4.30%	
	Preference Shares			
7.	Preference Share Summary	100.0		4.6
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		4.6
11.	Calculated Cost Rate		4.64%	
	Common Equity			
12.	Board Formula ROE		10.17%	

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2017 FORECAST YEAR

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost
			($Millions)		($Millions)
Medium Term Notes					
1.	8.85%	October 2, 2025	20.0	8.970%	1.8
2.	7.60%	October 29, 2026	100.0	8.086%	8.1
3.	6.65%	November 3, 2027	100.0	6.711%	6.7
4.	6.10%	May 19, 2028	100.0	6.161%	6.2
5.	6.05%	July 5, 2023	100.0	6.383%	6.4
6.	6.90%	November 15, 2032	150.0	6.950%	10.4
7.	6.16%	December 16, 2033	150.0	6.180%	9.3
8.	5.21%	February 25, 2036	300.0	5.183%	15.5
9.	4.77%	December 17, 2021	175.0	5.310%	9.3
10.	5.16%	December 4, 2017	191.7	5.220%	10.0
11.	4.04%	November 23, 2020	200.0	5.209%	10.4
12.	4.95%	November 22, 2050	200.0	4.990%	10.0
13.	4.95%	November 22, 2050	100.0	4.731%	4.7
14.	4.10%	August 15, 2023	400.0	4.180%	16.7
15.	3.80%	September 15, 2024	195.0	3.850%	7.5
16.	3.90%	September 15, 2024	20.0	3.980%	0.8
17.	4.30%	September 15, 2044	130.0	4.320%	5.6
18.	4.70%	September 15, 2044	85.0	4.720%	4.0
19.	4.30%	June 15, 2025	130.0	4.350%	5.7
20.	5.00%	October 15, 2025	145.0	5.050%	7.3
21.	4.60%	October 15, 2045	130.0	4.620%	6.0
22.	5.60%	October 15, 2045	145.0	5.620%	8.1
23.	4.60%	September 15, 2026	162.0	4.650%	7.5
24.	5.80%	November 15, 2027	31.3	5.850%	1.8
25.			3,460.0		179.8
Long-Term Debentures					
26.	9.85%	December 2, 2024	85.0	9.910%	8.4
27.			85.0		8.4
28.	Removal of separately treated CIS 64% assumed debt of 2017 $19.7M rate base value		(12.6)	5.350%	(0.7)
29.	Total Term Debt		3,532.4		187.5

Witness: K. Culbert

UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	18.5
2.	January 31	18.2
3.	February	17.9
4.	March	17.6
5.	April	17.3
6.	May	17.1
7.	June	16.8
8.	July	16.5
9.	August	16.2
10.	September	15.9
11.	October	15.6
12.	November	16.5
13.	December	16.2
14.	Average of Monthly Averages	16.9

Witness: K. Culbert

PREFERENCE SHARES
SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST
2017 FORECAST YEAR

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal ($Millions)	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost ($Millions)
	Fixed/Floating Cumulative Redeemable Convertible $25 Par Value				
1.	N/A	Group 3 Series D	100.0	4.64%	4.6
2.	Total		100.0		4.6

UNAMORTIZED PREFERENCE SHARE ISSUE EXPENSE
AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Unamortized Issue Expense
		($Millions)
1.	January 1	-
2.	January 31	-
3.	February	-
4.	March	-
5.	April	-
6.	May	-
7.	June	-
8.	July	-
9.	August	-
10.	September	-
11.	October	-
12.	November	-
13.	December	-
14.	Average of Monthly Averages	-

Witness: K. Culbert

COST OF CAPITAL
2018 FORECAST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,614.9	61.28	5.36	3.285
2.	Short-Term Debt	60.5	1.02	4.30	0.044
3.		3,675.4	62.30		3.329
4.	Preference Shares	100.0	1.70	4.64	0.079
5.	Common Equity	2,123.7	36.00	10.27	3.697
6.		5,899.1	100.00		7.105
7.	Rate Base	($Millions)			5,899.1
8.	Utility Income	($Millions)			277.9
9.	Indicated Rate of Return				4.711
10.	Deficiency in Rate of Return				(2.394)
11.	Net Deficiency	($Millions)			(141.2)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(192.1)
13.	Customer Care/CIS Deficiency	($Millions)	($133.8 vs $110.2)		(23.6)
14.	Total Gross Revenue Deficiency	($Millions)			(215.7)
15.	Revenue at Existing Rates	($Millions)			2,703.3
16.	Allowed Revenue	($Millions)			2,919.0
17.	Gross Revenue Deficiency	($Millions)			(215.7)
	Common Equity				
18.	Allowed Rate of Return				10.270
19.	Earnings on Common Equity				3.619
20.	Deficiency in Common Equity Return				(6.651)

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2018 FORECAST YEAR

Line No.		Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	3,629.8		194.5
2.	Unamortized Finance Costs	(14.9)		-
3.	(Profit)/Loss on Redemption	-		-
4.		3,614.9		194.5
5.	Calculated Cost Rate		5.36%	
	Short-Term Debt			
6.	Calculated Cost Rate		4.30%	
	Preference Shares			
7.	Preference Share Summary	100.0		4.6
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		4.6
11.	Calculated Cost Rate		4.64%	
	Common Equity			
12.	Board Formula ROE		10.27%	

Witness: K. Culbert

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2018 FORECAST YEAR

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal ($Millions)	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost ($Millions)
Medium Term Notes					
1.	8.85%	October 2, 2025	20.0	8.970%	1.8
2.	7.60%	October 29, 2026	100.0	8.086%	8.1
3.	6.65%	November 3, 2027	100.0	6.711%	6.7
4.	6.10%	May 19, 2028	100.0	6.161%	6.2
5.	6.05%	July 5, 2023	100.0	6.383%	6.4
6.	6.90%	November 15, 2032	150.0	6.950%	10.4
7.	6.16%	December 16, 2033	150.0	6.180%	9.3
8.	5.21%	February 25, 2036	300.0	5.183%	15.5
9.	4.77%	December 17, 2021	175.0	5.310%	9.3
10.	4.04%	November 23, 2020	200.0	5.209%	10.4
11.	4.95%	November 22, 2050	200.0	4.990%	10.0
12.	4.95%	November 22, 2050	100.0	4.731%	4.7
13.	4.10%	August 15, 2023	400.0	4.180%	16.7
14.	3.80%	September 15, 2024	195.0	3.850%	7.5
15.	3.90%	September 15, 2024	20.0	3.980%	0.8
16.	4.30%	September 15, 2044	130.0	4.320%	5.6
17.	4.70%	September 15, 2044	85.0	4.720%	4.0
18.	4.30%	June 15, 2025	130.0	4.350%	5.7
19.	5.00%	October 15, 2025	145.0	5.050%	7.3
20.	4.60%	October 15, 2045	130.0	4.620%	6.0
21.	5.60%	October 15, 2045	145.0	5.620%	8.1
22.	4.60%	September 15, 2026	162.0	4.650%	7.5
23.	5.80%	November 15, 2027	250.0	5.850%	14.6
24.	5.80%	January 15, 2028	62.3	5.880%	3.7
25.			3,549.3		186.3
Long-Term Debentures					
26.	9.85%	December 2, 2024	85.0	9.910%	8.4
27.			85.0		8.4
28.	Removal of separately treated CIS 64% assumed debt of 2018 $7.0M rate base value		(4.5)	5.350%	(0.2)
29.	Total Term Debt		3,629.8		194.5

UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	16.2
2.	January 31	16.4
3.	February	16.1
4.	March	15.8
5.	April	15.5
6.	May	15.2
7.	June	14.9
8.	July	14.6
9.	August	14.3
10.	September	14.0
11.	October	13.7
12.	November	13.4
13.	December	13.1
14.	Average of Monthly Averages	14.9

PREFERENCE SHARES
SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST
2018 FORECAST YEAR

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost
			($Millions)		($Millions)
Fixed/Floating Cumulative Redeemable Convertible $25 Par Value					
1.	N/A	Group 3 Series D	100.0	4.64%	4.6
2.	Total		100.0		4.6

UNAMORTIZED PREFERENCE SHARE ISSUE EXPENSE
AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Unamortized Issue Expense
		($Millions)
1.	January 1	-
2.	January 31	-
3.	February	-
4.	March	-
5.	April	-
6.	May	-
7.	June	-
8.	July	-
9.	August	-
10.	September	-
11.	October	-
12.	November	-
13.	December	-
14.	Average of Monthly Averages	-

Witness: K. Culbert

REVENUE DEFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2017 FORECAST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,515.5	61.49	5.31	3.265
2.	Short-Term Debt	43.3	0.76	4.30	0.033
3.		3,558.8	62.25		3.298
4.	Preference Shares	100.0	1.75	4.64	0.081
5.	Common Equity	2,058.1	36.00	10.17	3.661
6.		5,716.9	100.00		7.040
7.	Rate Base	($Millions)			5,716.9
8.	Utility Income	($Millions)			293.9
9.	Indicated Rate of Return				5.141
10.	Deficiency in Rate of Return				(1.899)
11.	Net Deficiency	($Millions)			(108.6)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(147.7)
13.	Customer Care/CIS Deficiency	($Millions)	($128.6 vs $110.2)		(18.4)
14.	Total Gross Revenue Deficiency	($Millions)			(166.1)
15.	Revenue at Existing Rates	($Millions)			2,693.2
16.	Allowed Revenue	($Millions)			2,859.3
17.	Gross Revenue Deficiency	($Millions)			(166.1)
	Common Equity				
18.	Allowed Rate of Return				10.170
19.	Earnings on Common Equity				4.894
20.	Deficiency in Common Equity Return				(5.276)

Witness: K. Culbert

ALLOWED REVENUE
AND DEFICIENCY
2017 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base	B6.T1.S1.P1	5,716.9	19.7	5,736.6
2.	Required rate of return	E6.T1.S1.P1	7.04%	6.44%	7.04%
3.			402.5	1.3	403.8
	Cost of Service				
4.	Gas costs	D6.T1.S1.P1	1,632.5	-	1,632.5
5.	Operation and maintenance	D6.T1.S1.P1	346.1	104.4	450.5
6.	Depreciation and amortization	D6.T1.S1.P1	300.7	12.7	313.4
7.	Fixed financing costs	D6.T1.S1.P1	1.9	-	1.9
8.	Municipal and other taxes	D6.T1.S1.P1	47.9	-	47.9
9.			2,329.1	117.1	2,446.2
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue	C6.T1.S1.P1	(41.2)	-	(41.2)
11.	Interest and property rental	C6.T1.S1.P1	0.0	-	-
12.	Other income	C6.T1.S1.P1	(0.1)	-	(0.1)
13.			(41.3)	-	(41.3)
	Income taxes on earnings				
14.	Excluding tax shield	D6.T1.S1.P3	51.3	7.5	58.8
15.	Tax shield provided by interest expense	D6.T1.S1.P3	(50.0)	(0.2)	(50.2)
16.			1.3	7.3	8.6
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS	E6.T1.S1.P1	(147.7)	-	(147.7)
18.	Net deficiency -w/out CC/CIS	E6.T1.S1.P1	(108.6)	-	(108.6)
19.			39.1	-	39.1
20.	Sub-total Allowed Revenue		2,730.7	125.7	2,856.4
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	2.9	2.9
22.	**Allowed Revenue**		2,730.7	128.6	2,859.3
	Revenue at existing Rates				
23.	Gas sales	C6.T1.S1.P1	2,388.5	91.8	2,480.3
24.	Transportation service	C6.T1.S1.P1	192.7	18.4	211.1
25.	Transmission, compression and storage	C6.T1.S1.P1	1.8	-	1.8
26.	Rounding adjustment		-	-	-
27.	Total		2,583.0	110.2	2,693.2
28.	**Gross revenue deficiency**		(147.7)	(18.4)	(166.1)

Witness: K. Culbert

UTILITY INCOME
2017 FORECAST YEAR

Line No.		Col. 1 Utility Income Excl. CIS & Customer Care ($Millions)	Col. 2 CIS & Customer Care ($Millions)	Col. 3 Total Utility Income ($Millions)
1.	Gas sales	2,388.5	91.8	2,480.3
2.	Transportation of gas	192.7	18.4	211.1
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue (Ex. C6-1-1-pg.1)	2,624.3	110.2	2,734.5
8.	Gas costs	1,632.5	-	1,632.5
9.	Operation and maintenance	346.1	104.4	450.5
10.	Depreciation and amortization expense	300.7	12.7	313.4
11.	Fixed financing costs	1.9	-	1.9
12.	Municipal and other taxes	47.9	-	47.9
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service (Ex. D6-1-1-pg.1)	2,329.1	117.1	2,446.2
16.	Utility income before income taxes	295.2	(6.9)	288.3
17.	Income tax expense (Ex. D6-1-1-pg.3)	1.3	7.3	8.6
18.	Utility income	293.9	(14.2)	279.7

Witness: K. Culbert

UTILITY RATE BASE
2017 FORECAST YEAR

Line No.		Col. 1 2017 Forecast Year Excl. CIS & Customer Care	Col. 2 2017 Forecast Year CIS & Customer Care	Col. 3 Total 2017 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	8,686.6	127.1	8,813.7
2.	Accumulated depreciation	(3,258.4)	(107.4)	(3,365.8)
3.	Net property, plant, and equipment	5,428.2	19.7	5,447.9
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	40.0	-	40.0
11.	Total Working Capital	288.7	-	288.7
12.	Utility Rate Base	5,716.9	19.7	5,736.6

Witness: K. Culbert

REVENUE DEFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2018 FORECAST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,614.9	61.28	5.36	3.285
2.	Short-Term Debt	60.5	1.02	4.30	0.044
3.		3,675.4	62.30		3.329
4.	Preference Shares	100.0	1.70	4.64	0.079
5.	Common Equity	2,123.7	36.00	10.27	3.697
6.		5,899.1	100.00		7.105
7.	Rate Base	($Millions)			5,899.1
8.	Utility Income	($Millions)			277.9
9.	Indicated Rate of Return				4.711
10.	Deficiency in Rate of Return				(2.394)
11.	Net Deficiency	($Millions)			(141.2)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(192.1)
13.	Customer Care/CIS Deficiency	($Millions)	($133.8 vs $110.2)		(23.6)
14.	Total Gross Revenue Deficiency	($Millions)			(215.7)
15.	Revenue at Existing Rates	($Millions)			2,703.3
16.	Allowed Revenue	($Millions)			2,919.0
17.	Gross Revenue Deficiency	($Millions)			(215.7)
	Common Equity				
18.	Allowed Rate of Return				10.270
19.	Earnings on Common Equity				3.619
20.	Deficiency in Common Equity Return				(6.651)

Witness: K. Culbert

ALLOWED REVENUE
AND DEFICIENCY
2018 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base	B7.T1.S1.P1	5,899.1	7.0	5,906.1
2.	Required rate of return	E7.T1.S1.P1	7.11%	6.44%	7.11%
3.			419.4	0.5	419.9
	Cost of Service				
4.	Gas costs	D7.T1.S1.P1	1,632.5	-	1,632.5
5.	Operation and maintenance	D7.T1.S1.P1	353.3	108.5	461.8
6.	Depreciation and amortization	D7.T1.S1.P1	309.4	12.7	322.1
7.	Fixed financing costs	D7.T1.S1.P1	1.9	-	1.9
8.	Municipal and other taxes	D7.T1.S1.P1	50.4	-	50.4
9.			2,347.5	121.2	2,468.7
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue	C7.T1.S1.P1	(41.2)	-	(41.2)
11.	Interest and property rental	C7.T1.S1.P1	0.0	-	-
12.	Other income	C7.T1.S1.P1	(0.1)	-	(0.1)
13.			(41.3)	-	(41.3)
	Income taxes on earnings				
14.	Excluding tax shield	D7.T1.S1.P3	60.7	7.2	67.9
15.	Tax shield provided by interest expense	D7.T1.S1.P3	(52.0)	(0.1)	(52.1)
16.			8.7	7.1	15.8
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS	E7.T1.S1.P1	(192.1)	-	(192.1)
18.	Net deficiency -w/out CC/CIS	E7.T1.S1.P1	(141.2)	-	(141.2)
19.			50.9	-	50.9
20.	Sub-total Allowed Revenue		2,785.2	128.8	2,914.0
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	5.0	5.0
22.	**Allowed Revenue**		2,785.2	133.8	2,919.0
	Revenue at existing Rates				
23.	Gas sales	C7.T1.S1.P1	2,404.4	91.8	2,496.2
24.	Transportation service	C7.T1.S1.P1	186.6	18.4	205.0
25.	Transmission, compression and storage	C7.T1.S1.P1	1.8	-	1.8
26.	Rounding adjustment		0.3	-	0.3
27.	Total		2,593.1	110.2	2,703.3
28.	**Gross revenue deficiency**		(192.1)	(23.6)	(215.7)

Witness: K. Culbert

UTILITY INCOME
2018 FORECAST YEAR

Line No.		Col. 1 Utility Income Excl. CIS & Customer Care ($Millions)	Col. 2 CIS & Customer Care ($Millions)	Col. 3 Total Utility Income ($Millions)
1.	Gas sales	2,404.4	91.8	2,496.2
2.	Transportation of gas	186.6	18.4	205.0
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue (Ex. C7-1-1-pg.1)	2,634.1	110.2	2,744.3
8.	Gas costs	1,632.5	-	1,632.5
9.	Operation and maintenance	353.3	108.5	461.8
10.	Depreciation and amortization expense	309.4	12.7	322.1
11.	Fixed financing costs	1.9	-	1.9
12.	Municipal and other taxes	50.4	-	50.4
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service (Ex. D7-1-1-pg.1)	2,347.5	121.2	2,468.7
16.	Utility income before income taxes	286.6	(11.0)	275.6
17.	Income tax expense (Ex. D7-1-1-pg.3)	8.7	7.1	15.8
18.	Utility income	277.9	(18.1)	259.8

Witness: K. Culbert

UTILITY RATE BASE
2018 FORECAST YEAR

Line No.		Col. 1 2018 Forecast Year Excl. CIS & Customer Care	Col. 2 2018 Forecast Year CIS & Customer Care	Col. 3 Total 2018 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	9,042.2	127.1	9,169.3
2.	Accumulated depreciation	(3,431.7)	(120.1)	(3,551.8)
3.	Net property, plant, and equipment	5,610.5	7.0	5,617.5
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	39.9	-	39.9
11.	Total Working Capital	288.6	-	288.6
12.	Utility Rate Base	5,899.1	7.0	5,906.1

Witness: K. Culbert

EXHIBIT LIST

A – ADMINISTRATIVE AND MODEL DESIGN

Exhibit	Tab	Schedule	Contents	Witness(es)
A1	1	1	Exhibit List	R. Bourke
	2	1	Application	R. Bourke
	3	1	Approvals Requested	R. Bourke
	4	1	Draft Issues List	R. Bourke
	5	1	Conditions of Service	T. Ferguson S. McGill
		2	Schedule of Service Charges – Rider G	S. McGill M. Torriano
	6	1	Curriculum Vitae of Company Witnesses	R. Bourke
		2	Curriculum Vitae of Company Witnesses	M. Lister
		3	Curriculum Vitae of Julia Frayer – London Economics	M. Lister
		4	Curriculum Vitae of Concentric Consultants	M. Lister
	7	1	Procedural Orders	

Proposals for the Model

Exhibit	Tab	Schedule	Contents	Witness(es)
A2	1	1	Customized IR Plan	R. Fischer M. Lister

EXHIBIT LIST

A – ADMINISTRATIVE AND MODEL DESIGN

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

EXHIBIT LIST

A – ADMINISTRATIVE AND MODEL DESIGN

EXHIBIT LIST

B – RATE BASE AND CAPITAL EXPENDITURES

Exhibit	Tab	Schedule	Contents	Witness(es)
Rate Base and Capital Expenditures 2014 to 2016				
B1	1	1	Rate Base Evidence and Summaries	K. Culbert
		2	Rate Base - Year to Year Summary	K. Culbert
	2	1	Economic Feasibility Procedure and Policy	F. Ahmad P. Squires
	3	1	Community Expansion	T. MacLean D. McIlwraith
Capital Expenditure Budget by Business Area				
B2	1	1	Capital Budget Overview	A. Mandyam J. Sanders
	2	1	Capital Budget: 2014 to 2016 Growth	F. Ahmad D. Lapp
	3	1	Capital Business Area - Reinforcements	E. Naczynski
		2	Capital Business Area - Major Reinforcements	C. Fernandes D. Lapp
	4	1	Capital Business Area - Relocations	L. Chiotti I. Taylor
	5	1	Capital Business Area – System Integrity and Reliability - Overview	L. Lawler J. Sanders
		2	Capital Requirements - Mains Replacement	D. Lapp L. Lawler J. Sanders
		3	Capital Requirements - Services Replacement	D. Lapp L. Lawler

EXHIBIT LIST

B – RATE BASE AND CAPITAL EXPENDITURES

Exhibit	Tab	Schedule	Contents	Witness(es)
B2	5	4	Capital Requirements - Stations Replacement and Upgrade	S. Surdu N. Thalassinos
		5	System Integrity & Reliability – Other Programs & Projects 2014 to 2016	A. Creery C. McCowan
		6	System Integrity & Reliability: Direct Resource Costs	A. Mandyam J. Sanders
	6	1	Capital Business Area – Storage	D. Dalpe B. Pilon
	7	1	Capital Business Area - Business Development	R. Murray
	8	1	Capital Business Area - Information Technology	T. Adesipo B. Misra
		2	Work and Asset Management Solution (“WAMS”)	W. Akkermans M. Brophy
	9	1	Capital Business Area - Facilities and General Plant	D. Lapp P. Rapini R. Riccio
	10	1	The Company’s Asset Plan 2013-2022	L. Chiotti

2014 Fiscal Year Rate Base

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

EXHIBIT LIST

B – RATE BASE AND CAPITAL EXPENDITURES

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

EXHIBIT LIST

B – RATE BASE AND CAPITAL EXPENDITURES

Exhibit	Tab	Schedule	Contents	Witness(es)
2018 Rate Base Forecast				
B7	1	1	Utility Rate Base - 2018 Forecast	K. Culbert
		2	Utility PP&E (excluding CC/CIS) 2018 Summary & AOMA's	K. Culbert
		3	Working Capital Components – 2018 Forecast	K. Culbert

EXHIBIT LIST

C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
Revenue Forecast Summaries				
C1	1	1	Operating Revenue Summary	S. Kancharla R. Lei S. Qian
	2	1	Gas Volume Budget	R. Cheung S. Qian
	3	1	Transactional Services (TS)	J. Denomy J. LeBlanc D. Small
	4	1	Other Service Charges, Administrative and Late Payment Penalty (LPP) Revenue	S. McGill M. Torriano
	5	1	GTA Project Revenue Requirement And Revenue Requirement for Shared Pipeline with TransCanada	K. Culbert C. Fernandes A. Kacicnik
Economic Forecasts				
C2	1	1	Key Economic Assumptions	H. Sayyan M. Suarez
		2	Heating Degree Day Forecast	H. Sayyan M. Suarez
		3	Average Use Forecasting Model	H. Sayyan M. Suarez
2014 Fiscal Year Revenue				
C3	1	1	Utility Operating Revenue 2014 Fiscal Year	K. Culbert

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C – OPERATING REVENUE

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

2015 Revenue Forecast

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

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
C4	2	1	Customers, Volumes and Revenues by Rate Class - 2015 Forecast	R. Cheung S. Qian
		2	Comparison of Average Customer Numbers by Rate Class 2015 Forecast and 2014 Fiscal Year	R. Cheung S. Qian
		3	Comparison of Gas Sales and Transportation Volume by Rate Class 2015 Forecast and 2014 Fiscal Year	R. Cheung S. Qian
		4	Comparison of Gas Sales and Transportation Revenue by Rate Class 2015 Forecast and 2014 Fiscal Year	R. Cheung S. Qian
	3	1	Details of Other Revenue 2015 Forecast and 2014 Fiscal Year	R. Lei S. Qian

2016 Revenue Forecast

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

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C – OPERATING REVENUE

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

2017 Revenue Forecast

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

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

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

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D1	13	1	Operations – O&M Budget	J. Alton D. Dalpe D. Lapp M. Wagle
	14	1	Information Technology – O&M Budget	T. Adesipo B. Misra
	15	1	Business Development and Corporate Strategy - O&M Budget	L. Kennedy P. Squires
	16	1	Human Resources Department O&M Budget	R. Riccio S. Trozzi
	17	1	Pipeline Integrity and Engineering – O&M Budget	J. Briggs A. Creery L. Lawler
	18	1	Regulatory, Public and Government Affairs – O&M Budget	K. Culbert P. Green R. Small
	19	1	Energy Supply and Policy	J. LeBlanc
	20	1	Non-Departmental O&M Expense	M. Lee S. Trozzi

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

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C – OPERATING REVENUE

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

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2016 Forecast				
D5	1	1	Utility Operating Costs 2016 Forecast	K. Culbert
	2	1	Cost Comparison of Utility Operating Cost and Expenses 2016 Forecast and 2015 Forecast	S. Kancharla R. Lei
		2	2016 Forecast Operating & Maintenance Expense by Department	S. Kancharla R. Lei
		3	Operating and Maintenance Expense by Cost Type - 2016 Forecast vs. 2013 Board Approved	S. Kancharla R. Lei
		4	2016 Forecast - Salaries & Wages and FTE Forecast	S. Kancharla R. Lei S. Trozzi
	3	1	2016 Gas Cost, Transportation and Storage	J. Denomy D. Small
		2	2016 Forecast Summary of Gas Cost Charged to Operations	J. Denomy D. Small
		3	2016 Forecast Summary of Storage and Transportation Costs	J. Denomy D. Small
		4	2016 Forecast Peak Day Supply Mix	J. Denomy D. Small

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C – OPERATING REVENUE

Exhibit	Tab	Schedule	Contents	Witness(es)
D5	3	5	2016 Forecast Monthly Pricing Information	J. Denomy D. Small
		6	2016 Forecast Gas Supply/Demand	J. Denomy D. Small
	4	1	2016 Forecast Unbilled and Unaccounted-for (UAF) Gas Volumes	H. Sayyan M. Suarez
2017 Forecast				
D6	1	1	Cost of Service 2017 Forecast Year	K. Culbert
	2	1	Cost Comparison of Utility Operating Cost and Expenses 2017 Forecast and 2016 Forecast	S. Kancharla R. Lei
		2	2017 Forecast Operating & Maintenance Expense by Department	S. Kancharla R. Lei
		3	Operating and Maintenance Expense by Cost Type - 2017 Forecast vs. 2013 Board Approved	S. Kancharla R. Lei
		4	FTE and Salaries & Wages 2017 Budget Year	S. Kancharla R. Lei S. Trozzi
2018 Forecast				
D7	1	1	Cost of Service 2018 Forecast Year	K. Culbert
	2	1	Cost Comparison of Utility Operating Cost and Expenses 2018 Forecast and 2017 Forecast	S. Kancharla R. Lei

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C – OPERATING REVENUE

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

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

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

2018 Forecast Capital Structure

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

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Exhibit	Tab	Schedule	Contents	Witness(es)
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F – REVENUE SUFFICIENCY/DEFICIENCY

Exhibit	Tab	Schedule	Contents	Witness(es)
Written Evidence				
F1	1	1	Revenue (Deficiency) / Sufficiency Summary	K. Culbert
		2	Allowed Revenue (Deficiency)/Sufficiency 2014 to 2016	K. Culbert
		3	Allowed Revenue (Deficiency)/Sufficiency 2017 to 2018	K. Culbert
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F3	1	1	2014 Fiscal Year Revenue Sufficiency Calculation And Required Rate Of Return	K. Culbert
		2	Utility Income 2014 Fiscal Year	K. Culbert
		3	Utility Rate Base 2014 Fiscal Year	K. Culbert
2015 Forecast Revenue				
F4	1	1	2015 Forecast Revenue Deficiency Calculation And Required Rate Of Return	K. Culbert
		2	Utility Income 2015 Forecast	K. Culbert
		3	Utility Rate Base 2015 Forecast	K. Culbert

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F – REVENUE SUFFICIENCY/DEFICIENCY

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

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

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G – COST ALLOCATION

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

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G – COST ALLOCATION

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	2	1	Proposed Changes to Terms and Conditions to Services in the Rate Handbook	J. Collier A. Kacicnik
		2	Proposed Rate Change – Rate 100	J. Collier A. Kacicnik
		3	Proposed Rate Change – Rate 110	J. Collier A. Kacicnik
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	2	1	Proposed Revenue Recovery by Rate Class	J. Collier
	3	1	Summary of Proposed Rate Change by Rate Class	J. Collier
	4	1	Calculation of Gas Supply Charges by Rate Class	J. Collier
	5	1	Detailed Revenue Calculations by Rate Class	J. Collier
	6	1	Rate Handbook	J. Collier
	7	1	Annual Bill Comparison	J. Collier

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I.A1.EGDI.CME.1 to 3, 10	CME Interrogatories	EGDI
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I.A1.EGDI.OAPPA.2	OAPPA Interrogatories	EGDI
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I.A10.EGDI.EP.6 to 10	Energy Probe Interrogatories	EGDI
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I.E35.EGDI.CME.7	CME Interrogatory	EGDI
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			Energy Probe Submission – September 4, 2013	
			SEC Submission – July 20 and August 7, 2013	
			VECC Submission – August 20, 2013	
L	1	1	PEG Report – Revised April 27, 2012	
		2	PEG Report – October 2013	

EXHIBIT LIST

N – SETTLEMENT PROPOSAL

CUSTOMIZED IR PLAN

Summary

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

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

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

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

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

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

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

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

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

Witnesses: R. Fischer
M. Lister

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

Witnesses: R. Fischer
M. Lister

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

Witnesses: R. Fischer
M. Lister

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

Estimated Rate and Bill Impacts including SRC rate rider credit

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

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

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

A. Objectives of an Incentive Regulation Plan

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

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

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

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

22. Taken together, the Board's objectives make clear that a gas distributor's IR plan must:

a. ensure appropriate reliability and quality of service (including safe operations);
b. protect customers from unreasonable price impacts;
c. promote energy conservation and efficiency;
d. protect the financial viability of the distributor and allow for appropriate investments to be made; and
e. provide a framework that incents the distributor to implement sustainable efficiency improvements.

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

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

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

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

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

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

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Summary of Capital Expenditures

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

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

Witnesses: R. Fischer
M. Lister

(i) *safety and integrity spending*

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

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

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

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

Witnesses: R. Fischer
M. Lister

(ii) major projects

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

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

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

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

(iii) customer growth

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

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

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

(iv) *relocation requirements*

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

b. Other costs pressures

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

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

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

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

Witnesses: R. Fischer
M. Lister

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

c. Productivity Challenges

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

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

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

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

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

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

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

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

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

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

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

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

D. 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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Witnesses: R. Fischer
M. Lister

b. Considerations for Enbridge's next Incentive Regulation plan

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

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

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

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

a. Allowed Revenue

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

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

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

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

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

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

Witnesses: R. Fischer
M. Lister

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

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

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

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

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

b. Volumes and Gas Costs for 2014

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

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

c. Final Rates for 2014

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

d. Preliminary Rates for 2015 to 2018

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

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

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

Witnesses: R. Fischer
M. Lister

e. Annual Adjustments for 2015 to 2018

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

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

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

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

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

f. Deferral and Variance Accounts

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

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

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

Witnesses: R. Fischer
M. Lister

g. Earnings Sharing Mechanism (ESM)

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

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

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

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

h. Sustainable Efficiency Incentive Mechanism (SEIM)

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

Witnesses: R. Fischer
M. Lister

i. Off-Ramps

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

j. Z-Factor

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

k. Performance Measurement

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

Witnesses: R. Fischer
M. Lister

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

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

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

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

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

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

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

G. Implementation and Impacts of the Customized IR Plan

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

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

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

Estimated Rate and Bill Impacts including SRC rate rider credit

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

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

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

Witnesses: R. Fischer
M. Lister

IR PLAN PRODUCTIVITY

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

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

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

Witnesses: A. Mandyam
S. Kancharla
R. Fischer
M. Lister

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

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

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

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

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

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

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

<u>The Budget Forecasting Process</u>

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

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

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

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

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

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

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

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

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

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

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

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

Witnesses: A. Mandyam
S. Kancharla
R. Fischer
M. Lister

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.

Tests of Reasonableness

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

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

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

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

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

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

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

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

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

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

31. Concentric concludes(at page 49):

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

Witnesses: A. Mandyam
S. Kancharla
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Benchmarking

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Witnesses: A. Mandyam
S. Kancharla
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M. Lister

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.

Witnesses: A. Mandyam
S. Kancharla
R. Fischer
M. Lister

2014 TO 2018 RATE ADJUSTMENT PROCESS

1. This evidence describes Enbridge Gas Distribution's ("Enbridge" or the "Company") proposal to adjust rates for the years of the Customized IR plan term – 2014 to 2018.

2. The rate adjustment process under the Customized IR plan is very consistent with Enbridge's 1st Generation IR plan. Under the Customized IR plan, Allowed Revenue amounts will be set by the Board in this proceeding, and then subject to adjustment in annual Rate Adjustment proceedings from 2015 to 2018 to take account of updated impacts of volumes, gas costs and discrete pass-through cost items. Those same types of items were updated each year during the 1st Generation IR plan, though annual Rate Adjustment proceedings.

3. As explained in the updated Exhibit A2, Tab 1, Schedule 1, Enbridge has updated its Customized IR Plan to enable Allowed Revenue amounts to be set within this proceeding for all five years of the IR term (2014 to 2018). To accomplish this, Enbridge will set its 2017 and 2018 Capital Budgets based upon the 2016 Capital Budget. The rationale for why this is an appropriate approach is set out within the updated Exhibit B2, Tab 1, Schedule 1. This approach eliminates the requirement for Enbridge's 2017 and 2018 Capital Budgets to be presented and approved in a Phase I of the 2016 Rate Adjustment proceeding. Under this approach, Enbridge is at risk (except within three specified areas of spending) for any additional capital spending requirements in 2017 and 2018 other than those identified within the 2016 Capital Budget.

4. The evidence in this case presents Enbridge's cost forecasts required to build the annual Allowed Revenue amounts for the 2014 to 2016 years within Enbridge's

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

Customized IR plan. As explained below, these cost forecasts are also used, with appropriate adjustments, to build the Allowed Revenue amounts for 2017 and 2018.

5. Enbridge is requesting Board approval of Allowed Revenue amounts for each year from 2014 to 2018 within this Application.

6. As explained at Exhibit A2, Tab 2, Schedule 1, for the 2014 Fiscal Year Enbridge is also requesting approval of the 2014 volume forecast that underpins the revenue at existing rates and the resulting sufficiency / deficiency. Finally, Enbridge is seeking approval of the resulting rates for 2014.

7. Enbridge is not seeking approval of rates for 2015 to 2018 at this time. Rates for those years will be set through annual Rate Adjustment proceedings which will apply updated volume forecasts to the Allowed Revenue amounts approved in this proceeding. The 2015 to 2018 volume forecasts and the resulting revenues at existing rates presented in the case are intended to be proxies for the determination of revenues at existing rates, and the resulting revenue sufficiency/deficiency in those years.

8. In the following paragraphs, the Company sets out how:

    a. Allowed Revenue amounts for 2014 to 2018 will be determined within this proceeding.

    b. The annual Rate Adjustment process to set rates for each year from 2014 to 2018 will work, including:

        i. The process to set final rates for 2014; and

Witnesses: K. Culbert
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ii. The process to set final rates for 2015 to 2018, which will involve the updating of volumes and associated forecast revenues and gas costs, as well as updates within the final allowed Revenue Amounts for each year for customer care, DSM and pension/OPEB costs.

Process for Determining Allowed Revenue Amounts for 2014 to 2018

9. The Allowed Revenue amount for each year is determined by summing together the following elements: the cost of capital, operating costs, depreciation costs and taxes, less an offset amount for other revenues.

10. The Company has filed detailed evidence setting out how each of these elements, and the overall Allowed Revenue, can be determined for the years from 2014 to 2016. As explained in the updated Customized IR Plan evidence (Exhibit A2, Tab 1, Schedule 1), Enbridge cannot provide a reliable line-by-line forecast of capital spending requirements for 2017 and 2018 at this time However, in order to enable Allowed Revenue amounts for those years to be set in this proceeding, Enbridge's updated Customized IR Plan provides for the 2016 Capital Budget to be used to represent forecast 2017 and 2018 capital spending requirements.

11. As noted, Enbridge's updated Customized IR Plan provides for Allowed Revenue amounts for all five years of the IR term to be set in this proceeding. The components of Allowed Revenue are the same for all years. There are, however, differences between how these components are derived for 2014 to 2016 (based upon detailed budgets) as compared to 2017 and 2018 (where certain components are derived using adjustments to the 2014 to 2016 budgets). In the subsections below, explanation is provided about how the Allowed Revenue amounts will be set in this proceeding for 2014 to 2016, and for 2017 and 2018.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

12. The Allowed Revenue amounts for 2014 to 2018 that are being set within this proceeding are set out at the updated Exhibit F1, Tab 1, Schedule 1. These 2014 to 2018 Allowed Revenue amounts are referred to as ”final” in this evidence, because they will not be adjusted except to take account of the items that will be updated within the annual Rate Adjustment proceedings. The final Allowed Revenue amounts for 2015 to 2018 are to be used as the starting point within the annual Rate Adjustment proceedings to set final rates for 2015 through 2018. Final rates for 2014 are being set within this proceeding.

(i) Determination of the final Allowed Revenue amounts for 2014 to 2016, to be set within this proceeding

13. The Allowed Revenue amounts for each year from 2014 to 2016 are set based on the following elements:

    a. Rate Base: The 2014 value is determined beginning with the use of the 2013 Board-approved closing rate base values (from EB-2011-0354) and applying the forecast 2014 Capital Budget and working capital inputs and applying impacts of the return of site restoration cost (“SRC”) reserve amounts to determine the appropriate 2014 Rate Base level. The 2015 and 2016 Rate Base amounts are determined through the application of 2015 and 2016 Capital Budget and working capital inputs and site restoration cost (“SRC”) return impacts. The relevant evidence is set out in the B series of exhibits.

    b. Rate of Return on Rate Base: The values for each year are set through the application of the forecast debt rates, and level of debt, and the forecast applicable ROE level, as set out within the E series of exhibits.

Witnesses: K. Culbert
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c. Gas Costs: The values for each year are determined based upon the proxy volume forecasts as applied to the proxy gas supply plans for each year. This volume information is set out in in Exhibit C1, Tab 2, Schedule 1, and the gas costs forecasts are set out in Exhibits D3/D4/D5, Tab 3, Schedule 1. The Gas Costs inputs into Allowed Revenue will be updated within each annual Rate Adjustment proceeding.

d. Operating & Maintenance Costs: The values for each year are determined based upon the O&M Budget information set out in the D1 series of exhibits. The values related to customer care/CIS, pension/OPEB and DSM costs will be updated within each annual Rate Adjustment proceeding.

e. Depreciation Costs: The values for each year are determined based upon the forecast Capital Budget impacts, using the proposed updated depreciation rates. Evidence can be found within the B series of exhibits (Capital Budget) and at Exhibit D1, Tab 1, Schedule 1 and Exhibit D1, Tab 5, Schedule 1.

f. Fixed Financing Costs: The values for each year represent a forecast of the administration, extension and standby fees associated with the Company's committed credit facility. Evidence can be found at Exhibit E1, Tab 2, Schedule 1.

g. Municipal and Property Taxes: The values for each year are based on a forecast of taxes as applied to the Company's relevant assets. Evidence can be found within Exhibit D1, Tab 6, Schedule 1.

Witnesses: K. Culbert
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h. Other Operating Revenue: The values for each year are based on forecasts of revenues for items such as Transactional Services, Open Bill Access, Late Payment Penalties, Other Service Charges and DPAC. Evidence can be found within the C series of exhibits.

i. Income Taxes: The values for each year are based on a forecast of income tax rates applied to forecast utility taxable income. Evidence can be found in Exhibits D3/D4/D5, Tab 1, Schedule 1.

(ii) Determination of the final Allowed Revenue amounts for 2017 and 2018, to be set within this proceeding

14. The final Allowed Revenue amounts for 2017 and 2018 that are being set within this proceeding are provided within Exhibits F6 and F7, and are set based on the following elements:

    a. Rate Base: The 2017 Rate Base amount is determined beginning with the use of the 2016 closing rate base values and applying (as a reasonable forecast of 2017 requirements) the forecast 2016 Capital Budget[1] and working capital inputs and 2017 SRC return amount impacts to determine the appropriate 2017 Rate Base level. The 2018 Rate Base amount is determined through the application (as a reasonable estimate of 2018 requirements) of 2016 Capital Budget and working capital inputs and 2018 SRC return amount impacts.

[1] Note, as explained within Exhibit B2, Tab 1. Schedule 1, that the 2016 Capital Budget used for 2017 and 2018 is reduced by $8.1 million to account for the fact that the WAMS project costs will not recur in those years.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

b. Rate of Return on Rate Base: The values for each year are set through the application of the forecast debt rates, and level of debt, and the forecast applicable ROE level for 2017 and 2018, as set out within the E6 and E7 series of exhibits.

c. Gas Costs: The values for each year are determined based upon the proxy 2016 volume forecasts (used as a proxy for 2017 and 2018) as applied to the proxy gas supply plan for 2016. The Gas Costs inputs into Allowed Revenue will be updated within each annual Rate Adjustment proceeding.

d. Operating & Maintenance Costs: The values for 2017 and 2018 are determined as follows: (i) "Other O&M" and RCAM are combined, and the 2017 value is determined by applying the average rate of change in those costs from 2013 to 2016 to the 2016 forecast amount of "Other O&M" and RCAM; (ii) the 2018 amount for "Other O&M" and RCAM are determined by applying the same average rate of change to the 2017 value for those costs: (iii) the customer care/CIS costs are determined by applying the current forecast of customers within Exhibit D1, Tab 10, Schedule 3, to the per-customer amount set out in the updated EB-2011-0226 Template; (iv) the DSM amounts are determined by applying a 2% per year inflation amount to the 2016 forecast budget; and (v) the pension/OPEB amounts for 2017 and 2018 are those that are found within the Mercer studies attached to Exhibit D1, Tab 16, Schedule 1. The forecast level of costs for customer care/CIS, DSM and pension/OPEBs will be updated within the 2017 and 2018 Rate Adjustment proceedings.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

e. Depreciation Costs: The values for each year are determined based upon use of the 2016 forecast Capital Budget impacts (as a reasonable estimate of impacts for each of 2017 and 2018), using the proposed updated depreciation rates.

f. Fixed Financing Costs: The forecast values for 2017 and 2018 of the administration, extension and standby fees associated with the Company's committed credit facility are filed in updated Exhibit E1, Tab 2, Schedule 2.

g. Municipal and Property Taxes: The values for 2017 and 2018 are determined by calculating the average rate of change in these costs from 2013 to 2016, and applying that rate of change to the 2016 value, and then to the resulting forecast 2017 value.

h. Other Operating Revenue: The values for 2017 and 2018 are held flat at the 2016 level.

i. Income Taxes: The values for 2017 and 2018 are based on the forecast of income tax rates within Exhibits D3/D4/D5, Tab 1, Schedule 1, as applied to forecast utility taxable income, using the Allowed Revenue inputs described above.

<u>Rate Adjustment process to set rates for each year from 2014 to 2018</u>

15. The Company's proposal to set rates for 2014, based on the Allowed Revenue amount for 2014, is set out at Exhibit A2, Tab 2, Schedule 1.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

16. In order to set rates for 2015 to 2018, Enbridge proposes to follow a similar annual rate adjustment process as was used during the 1st Generation IR term. That is, Enbridge proposes to present the Board with an annual update of volumes, which when applied to existing rates, will determine the revenue forecast at existing rates. Enbridge will then compare the pre-determined Allowed Revenue for 2015 to 2018 as approved by the Board in this case, to the revenue forecast at existing rates to determine the revenue sufficiency or deficiency to be applied as a rate adjustment for the year being reviewed.

17. Normally, total volumes are determined by multiplying the average use forecast by the number of small volume customers and adding in total forecast industrial or other volumes. Enbridge believes the process may be somewhat streamlined by approving the customer additions forecast numbers for each year of the IR term within this proceeding (for 2014 to 2018). That is also consistent with the fact that the cost forecasts being presented for approval in those proceedings are premised in part on the customer additions forecasts being used. As a result, the Company proposes that there will be no updating of the customer additions forecast as part of the annual Rate Adjustment proceedings. Instead, the total volume forecast will be calculated using the approved customer additions.[2]

18. Finally, as in the 1st Generation IR term, Enbridge proposes to annually file and present an update of its gas supply plan. This Application presents estimates and assumptions regarding the supply and transportation contracting conditions that are expected to prevail based on current information. However, market changes over the course of the 2014 to 2018 period as a result of the completion of the GTA

[2] Note, however, that the Customer Care/CIS Settlement Agreement requires that EGD adjust the number of average unlocks each year for the determination of Customer Care/CIS costs that are to be adjusted each year through the Rate Adjustment proceedings.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

Reinforcement project, and uncertainties with respect to the TCPL Mainline may be material. An annual update of the gas supply plan has the advantage of capturing these market changes as they occur during the course of the IR term and benefits consumers by ensuring that the most appropriate contracting for upstream supplies is in place for each year. Once the annual gas supply plan has been approved, any variances from the annual plan would be captured in the PGVA and cleared within the normal course of the QRAM process.

19. Under this approach, risks for ratepayers and shareholders are reduced by annually reviewing volume forecasts. Specifically, since the volume forecast depends on the forecast annual degree days, an annual review and update will ensure that rates are set using the most up to date information using the Board Approved methodology for degree days. This will minimize the probability that volumes, and therefore rates, are set on an irrelevant weather basis.

20. To effect the setting of rates for 2015 to 2018, Enbridge proposes to file annual Rate Adjustment applications setting out:
    a. The approved final Allowed Revenue amount for the rate year;
    b. Forecast volumes for the rate year as determined by a degree day forecast, average use forecast, and other volume forecast;
    c. An updated gas supply plan;
    d. Updated Allowed Revenue amounts for Customer Care/CIS costs (calculated in accordance with the EB-2011-0226 Settlement Agreement) and pension/OPEB costs, which will replace the relevant amounts within the Allowed Revenue for that year;
    e. Any Z-Factor request, if necessary;

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

f. Proposed deferral and variance accounts for the rate year, including any forecast amounts for clearance, and the methodology for any proposed clearance of deferral or variance accounts;
g. A draft rate order; and
h. A rate handbook and supporting documentation explaining how rates have been adjusted.

21. As was the case for the 1st Generation IR period, the Company submits that a final rate order would need to be issued by December 15th, for any required rate adjustment to take effect by January 1st of the following year.

22. In order to accommodate a final rate order by December 15th, the Company proposes to file its rate adjustment application (without the supporting evidence) for each year by September 1st of the prior year, which will allow for the necessary administrative processes and notices to be produced.

23. Similar to the 1st Generation IR term, Enbridge will file the evidence in support of its rate adjustment applications by October 1st of each year. This will allow for the supporting evidence to be the most up-to-date and detailed information available in relation to rates for the following year. This timing will allow time enough for the Board and stakeholders to review the requested rate adjustment, pose interrogatories, and if necessary conduct a hearing, prior to the Board releasing a decision.

24. The Company has also proposed the inclusion of an Earnings Sharing Mechanism ("ESM") as part of this Customized IR proposal. As was the case for the 1st Generation IR proposal, Enbridge proposes to prepare and file and ESM calculation that pertains to each year of the plan following the release of its

Audited Financial Statements for the particular Fiscal Year. Enbridge will file an application containing this information with a proposal for clearance of any amount in the ESMDA and amounts in all other Board Approved deferral and variance accounts at that time.

25. For more information on the Company's proposed ESM, please refer to Exhibit A2, Tab 7, Schedule 1. For more information on other annual reporting related to performance measurement, and on the proposed Sustainable Efficiency Incentive Mechanism, please refer to Exhibit A2, Tab 11, Schedules 2 and 3.

Rate Design Changes during the Customized IR Term (2014 to 2018)

A) Energy Services

26. Gas utilities need rate design flexibility to respond to changing marketplace needs. The gas utilities accomplish this goal in two ways: a) by developing new rates and services, or b) by making specific changes to existing rates.

27. The unbundled rates and services that the Company has developed as part of the Natural Gas Electricity Interface Review ("NGEIR") generic proceeding (EB-2005-0551) are an example.

28. If the rate-related changes are minor in nature and customer impacts are minimal, the OEB's approval process could be included as part of the annual rate setting filing. However, if the rate-related changes are significant and warrant a longer review period, the Company will file a separate rate change application on a sufficiently timely basis.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

B) Miscellaneous and Non-Energy Services

29. Enbridge proposes that should Enbridge need to change or introduce new miscellaneous or non-energy services during the IR plan period, the Company will seek approval for the changes and provide the Board with supporting evidence.

Witnesses: K. Culbert
R. Fischer
A. Kacicknik

COST OF CAPITAL TREATMENT

1. This evidence sets out Enbridge's proposal and rationale for the treatment of the Cost of Capital in this Customized IR plan.

2. Enbridge has considered each of the following areas with respect to this proposal:
    a. Capital structure through the IR term
    b. Return on Equity ("ROE") through the IR term
    c. Cost of Capital for ESM purposes

Capital Structure

3. Through this Application, Enbridge proposes to fix the capital structure ratios that will apply through the term of the Customized IR plan for ratemaking purposes.

4. As a result of the 2013 Test Year Rebasing case (EB-2011-0354), the Board determined that Enbridge's equity ratio should remain at 36%. Enbridge proposes to maintain this equity ratio for ratemaking purposes for the duration of the IR term.

5. For the 2014 to 2018 period, Enbridge's use of long term debt, short term debt, and /u
preferred shares during the IR term have been developed according to the pace of required capital spending and the timing for cash flow needs. The financing plan for 2014-2018 is filed at Exhibit E1, Tab 2, Schedules 1 and 2, and sets out the /u
determination of the amounts, timing, and costs for each of long term debt, short term debt, and preferred share financing, and results in the following capital structure derived percentages:

Witnesses: K. Culbert
R. Fischer
M. Lister
M. Suarez-Sharma

Capital Structure Component	2014 Weight	2015 Weight	2016 Weight	2017 Weight	2018 Weight
Equity	36%	36%	36%	36%	36%
Long term debt	59.37%	61.41%	61.31%	61.49%	61.28%
Short term debt	2.34%	0.49%	0.87%	0.76%	1.02%
Preferred shares	2.29%	2.10%	1.82%	1.75%	1.70%

6. It should be noted that Enbridge's acceptance of the 36% for the equity ratio for the duration of the IR term is not an acceptance that this ratio meets the Fair Return Standard. While Enbridge is implementing this equity ratio for the duration of the Customized IR term, the Company reserves its rights to apply, at a later date, for an appropriate equity ratio that meets the Fair Return Standard in conjunction with a given ROE level and to take any position deemed appropriate if a generic Cost of Capital proceeding is convened.

7. Where the required level of capital spending is altered for purposes of determining eventual approved rates, the planned ratios of long and short term debt may be affected which could require a re-forecast of planned debt issuances.

<u>ROE through the IR term</u>

8. For ratemaking purposes, Enbridge proposes to include forecasted ROE levels for each year of the IR plan into the determination of Allowed Revenue for each fiscal year of the IR term. That is, a different ROE level will apply for each of 2014 to 2018, inclusive.

9. The forecasted ROE levels for 2014 through 2018 can be found at Exhibit E2, Tab 1, Schedules 1 and 2. /u

Witnesses: K. Culbert
R. Fischer
M. Lister
M. Suarez-Sharma

10. It is appropriate and reasonable to include the ROE forecasts directly into the derivation of the Allowed Revenue, as the cost of capital is a legitimate utility cost. In a traditional 'I-X' framework, forecast cost of capital is typically not included as it is believed that the inflation factor provides, at least in part, some compensation for changes in interest rates, which otherwise affect the level of Allowed ROE. In this proposed Customized IR approach, however, there is no explicit forecast of inflation, only a forecast of the costs that contribute to the Allowed Revenue. As such, it is reasonable that the Allowed Revenue forecasts should include representation for the forecast costs of capital that the utility will bear during the IR term.

11. EGD also considered an approach that would float the ROE, so that any updated ROE value would be used each year. That ROE value would be determined annually according to the Board Approved Formula at the time that the Formula output is known (i.e., approximately November of each year).

12. This alternative has the advantage of annually representing a true reflection of the cost of capital into rates, but the disadvantage of being another item for update and adjustment through the IR term. There is also difficulty with the timing of this approach, since a November date for ROE updates would make it a challenge to implement rates by January 1st of the following year. Given these disadvantages, Enbridge believes this alternative is not best suited to incentive regulation.

<u>Cost of Capital for ESM purposes through the IR term</u>

13. Discussion of the Company's ESM proposal can be found at Exhibit A2, Tab 7, Schedule 1. Enbridge proposes that if its actual ROE is more than 100 basis points above the Board's ROE Formula for that year, then it will equally share any

earnings above that level with ratepayers, subject to the Off Ramp Criteria at 300Bp or greater ROE (Exhibit A2, Tab 6, Schedule 1).

14. As explained in that evidence, Enbridge proposes that the Board's ROE Formula used to calculate the annual ESM amount should be annually adjusted according to the ROE formula set out in the Board's 2009 Cost of Capital report.

15. Enbridge proposes leaving its equity ratio unchanged for the purposes of calculating the amounts for ESM. Enbridge will leave the equity ratio unchanged at 36% even if there is a change to this amount as a result of any Cost of Capital review. While it would be ideal to calculate ESM on the basis of the most up to date cost of capital parameters in order to obtain a true reflection of the Fair Return Standard, this would be very difficult to implement. Changing the equity ratio for ESM purposes relative to what is used for ratemaking purposes would require the Company to estimate what financing would otherwise have taken place had rates been set to use an equity ratio different from 36%. This would require estimates for the amounts, timing, and costs of both short-term and long-term debt, and would therefore introduce layers of complexity, and potential controversy, into the calculation of earnings sharing.

Witnesses: K. Culbert
R. Fischer
M. Lister
M. Suarez-Sharma

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.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

10. EGD considered the information about similar mechanisms in other jurisdictions in conjunction with the intentions of the mechanism (as listed above) to develop its modified SEIM proposal.

11. The ECM that has been proposed in BC relates to FortisBC Energy Inc. That ECM would calculate net O&M and Net Plant savings by year of the IR plan term, which would then be shared equally between ratepayers and shareholders and summed over a rolling 5-year time horizon.[1] The application containing this request is ongoing, and there is no decision from the BC regulator.

12. The most relevant Canadian example that EGD reviewed is from Alberta. The Alberta Utilities Commission ("AUC") approved an ECM as proposed by ATCO Gas as part of the Rate Regulation Initiative.[2] Under that proposal, the ECM would be calculated as an add-on to the Approved ROE for up to two years following the term of the IR plan. The add-on would be equal to one half of the difference between the average ROE achieved over the term of the IR plan and the average approved ROE over the IR term. If the difference is positive, then that difference would be multiplied by 50%, and then the lessor of that result or 0.5% would apply as a premium to the Approved ROE for 2 years after the term of the IR plan.

13. In approving the ECM mechanism, the AUC commented as follows:

> 775. The Commission agrees that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects. The Commission finds that the incentive

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[1] FortisBC Energy Inc., Application for Approval of Multi-Year Performance Based Ratemaking Plans for 2014 through 2018: http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/130610_FEI_2012-2018_PBR_Application_Volume_1.pdf .

[2] Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance Based Regulation, September 12, 2012

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

> properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term. The Commission agrees with ATCO's proposal for an upper limit for earnings that can be carried over and finds the limit of 0.5 per cent to be reasonable. Accordingly, the Commission approves the ATCO companies' ROE ECM for inclusion in the ATCO companies' PBR plans. If any of the other companies wish to submit the same ECM in their PBR plans, they may do so in their compliance filings.[3]

14. The Company agrees with the intent of an ECM, as articulated by the AUC. EGD notes that the intent of the Alberta ECM is to strengthen incentives for utilities' IR plans. More specifically, this type of mechanism is intended to reduce the disincentive for a utility to invest in the latter years of an IR plan. That disincentive arises, ultimately, because the benefits to be derived by the productivity investment will be clawed back for the benefit of ratepayers at rebasing. As such, with a shorter duration for enjoyment of the benefits (i.e., in the latter years of the plan) the incentives for the utility to invest in productivity-enhancing initiatives is weakened. In some cases, this could lead to a situation where full recovery of the costs of the productivity-enhancing investment would not be achieved during the term of the IR plan.

15. The Company does note, however, that there may be some issues with the FortisBC and Alberta mechanisms that wouldn't necessarily correlate with the objectives for a SEIM as laid out above.

16. There are two main issues with the FortisBC proposal as EGD sees it. The first is that the mechanism doesn't directly incent long term efficiencies, and in fact, may strengthen the incentive to undertake short-term, temporary, cost cutting. That is, the utility would be able to simply defer costs until rebasing and still stand to gain an

[3] Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance Based Regulation, September 12, 2012, at para. 775.

ECM reward. A second issue arises in that the design of the mechanism may be seen to reward over-budgeting.

17. EGD also sees an issue with the ECM as it has been adopted by the AUC. The trigger for determining whether an ECM payout is due is not linked with achieved productivity gains. Both the amount of the Alberta ECM reward, and whether the award is merited, are based solely on historical earnings (a comparison of actual ROE to approved ROE) which may or may not have any bearing on long term, sustainable benefits. The fact that a utility has achieved an ROE in excess of the Board-approved level may or may not be related to productivity gains. That is to say that excess historical earnings may have arisen due to factors beyond the utilities' control, or that aren't related to long term ratepayer benefits. Again, this would contradict the Ontario objective of fostering sustainable efficiency gains.

18. EGD believes that an appropriately designed ECM/SEIM should contain measures that condition the receipt of the reward on actual performance and sustainable efficiency programs undertaken by the utility.

The Modified SEIM: EGD's Proposal

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:
   - o 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
   - o 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:
   - o 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
   - o 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):
   - o Step 1: Determine the reward potential
   - o Step 2: Demonstrate that the reward is justified
   - o Step 3: Apply the reward, if applicable

21. These three steps are described further below.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

Step 1: Determining the Reward Potential

The amount of the SEIM reward that is available is based on a comparison of EGD's average actual ROE for each year of the IR term compared to the Board-Allowed ROE for each year. The actual ROE to be used will be calculated in the same way as actual ROE is determined for ESM purposes. This SEIM reward (which will operate as a premium on the ROE that applies to rates for the rebasing year and the following year) will be equal to one half of the difference between the average ROE achieved during the IR term and the average Allowed ROE over the term of the plan. If the difference is positive, then that difference would be multiplied by 50%, to create a SEIM reward. The SEIM reward for each of the two years will be capped at a maximum of 50 basis points above the Allowed ROE.

Mathematically, the Reward Potential could be presented as follows:

> SEIM Reward Potential (ROE Premium) for each of 2019 and 2020= [Average Actual ROE (2014-2018) – Average Allowed ROE (2014-2018)]*50%*50%
>
> ROE Premium=Min[Reward Potential, 0.5%] (the lesser of the Reward Potential or 0.5%)

As a final step for this stage, the ROE premium will be expressed as a dollar amount, based on the forecast rate base level for 2019. This dollar amount (multiplied by two) will be used for the purpose of justifying the reward in the next step.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

Step 2: Demonstrating that the reward is justified

To qualify for the SEIM reward, EGD must show that the NPV of the long-term benefits generated by any productivity initiatives undertaken during the IR term are greater than the reward. The Company must also show that its service and performance have been maintained at or above the current level. The data and information used to make this determination would consist of the following items:

1. EGD will have to show that the NPV of the expected benefits from productivity initiatives undertaken during the IR term is greater than the dollar amount associated with the SEIM reward. The information to be used for this exercise will be included within the Productivity Initiatives Reports that are to be filed each year during the IR term (see Exhibit A2, Tab 11, Schedule 2). Within those reports, EGD will provide details of the projects, a description of how multi-year benefits accrue as a result of the projects, information about how the project costs were determined, and the details and assumptions used to estimate the long-term multi-year benefits anticipated from the projects. The NPV of the net benefits will be determined using the same financial parameters (capital structure, costs of capital, tax rates, etc.) as are used for customer additions feasibility analysis.

2. EGD will produce a Performance Metrics Benchmarking Report, as described at Exhibit A2, Tab 11, Schedule 2, which will set out the results of EGD and the industry average in relation to metrics around Customer Relationship and Operational Performance. To be permitted to recover the SEIM reward, EGD will need to establish that on average over the IR term, the Company has been able to maintain or improve its performance in these areas.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

3. Included within the Performance Metrics Benchmarking Report will be a reporting of EGD's Service Quality Requirements (SQR) performance over all years of the IR plan. To be permitted to recover the SEIM reward, EGD will need to establish that its overall SQR performance is maintained at or above the 2013 level for at least three of the five years of the IR term.

In the event that EGD seeks a SEIM reward for 2019 and 2020, the Company will include all of the above information within its rebasing application. Stakeholders will be free to take any position challenging any of the information brought forward or any other information challenging EGD's entitlement to the SEIM reward.

i Step 3: Applying the Reward

If EGD is successful in establishing its entitlement to a SEIM reward (ROE premium), then the reward would be administered within the 2019 rebasing case and the 2020 rates case, as follows:

SEIM Reward = 2019 Utility Rate Base * Utility Equity Ratio * ROE Premium

This amount would be added to the Revenue Requirement in the rebasing year for collection in that year. The same amount would be applied in the 2020 rates proceeding.

22. To provide further illustration of EGD's updated SEIM proposal, examples are provided below.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

Example 1:

- *Step 1*:

  Average Actual ROE = 9.5%

  Average Allowed ROE = 10.0%

  Reward Potential = (9.5% - 10.0%) = -0.5%

  EGD does not qualify for the reward.

Example 2:

- *Step 1*:

  Average Actual ROE = 10.5%

  Average Allowed ROE = 10.0%

  Reward Potential = (10.5% - 10.0%) = 0.5% * 50% * 50% = .125%

  ROE Premium = Min[0.125%, 0.5%] = 0.125%

  The ROE Premium would then be converted into a dollar amount.

  2019 Utility Rate Base * 2019 Utility Equity Ratio * 0.125%.

  Assume 2019 Utility Rate Base = $4 billion

  Assume 2019 Equity Ratio = 36%

  Therefore, the dollar value of the ROE premium for 2019 would be $1.8 million (4 billion * 36% * 0.125%).

  The same amount would be applied for 2020.

- *Step 2*:

  EGD will file information to establish entitlement to the SEIM reward.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

The data from the Productivity Initiatives Reports will have to demonstrate that the net present value of benefits from sustainable efficiency gains undertaken during the IR term exceeds $3.6 million.

EGD will also have to establish, through the Performance Metrics Benchmarking Report, that it has at least maintained its current Customer Relationship and Operational Performance levels over the IR term and has not experienced material shortcomings in overall SQR performance over the IR term.

- *Step 3*:
  If EGD successfully meets all thresholds above, then a reward of $1.8 million would flow to EGD for each of 2019 and 2020.

Conclusion

23. EGD believes that the redesigned SEIM achieves the goals of the mechanism more effectively, and address concerns raised by stakeholders. The goal of the SEIM is to produce incentives for management to undertake long-term, sustainable efficiencies. In particular, through the “carrot” of the potential SEIM “reward” at re-basing, the SEIM will encourage management to pursue initiatives where benefits may accrue beyond the term of the IRM cycle, which would exclusively benefit customers

24. The redesigned SEIM addresses each of the criticisms from stakeholders that were noted above :
    a) The SEIM reward is no longer calculated based on future unverified benefits

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

i) The SEIM reward is now calculated based on Enbridge's financial performance during the IR term, however,

(1) EGD will still have to establish that the NPV of the benefits to be achieved from sustainable productivity initiatives will be greater than the amount of the SEIM reward

(2) The reward will also be contingent on other demonstrated performance factors (i.e. ROE performance, Benchmarking performance, SQR performance)

b) The SEIM payout will no longer be an annual reward during the IR term

i) The modified SEIM is a one-time reward (if applicable) to be assessed for the rebasing year and the next year

c) There will be a cap on the amount of the SEIM reward payout

i) The modified SEIM sets out a maximum of a 0.5% ROE adder, but only if the long term ratepayer benefits exceed the reward sought.

25. Enbridge acknowledges that, at least in part, the modified SEIM will still be premised in part upon a quantification of future benefits from sustainable efficiency initiatives. The Company believes that this is the only viable way to implement the SEIM in a straightforward manner. It is not feasible to expect that projections of future financial benefits from efficiency gains will be validated at a future date in order to make adjustments to SEIM reward payments. The fact is that some productivity initiatives may have benefits that are forecast to run for three, five, ten or more years into the future. If the validation of such benefits is a requirement, then the SEIM for 2014 to 2018 would not be finalized until all the benefits have run their full course, which may be upwards of 10 years. This is clearly not feasible. Another option for validation would be to hire a 3rd party to conduct the validation, as occurs in the Demand Side Management evaluations. However, in the

Company's opinion, this creates layers of bureaucracy and administration that outweigh the benefit. That said, there will be an opportunity for the Board and stakeholders to review and comment on the Company's evidence around the productivity initiatives undertaken during the IR term and the associated NPV.

26. The Company believes that the updated SEIM proposal creates the right incentives, but conditions the reward on the justification of long term benefits to ratepayers, as opposed to mere reliance on historical earnings, which may or may not have any bearing on long term sustainable efficiencies. This proposal starts by adopting the ESM mechanism that was approved in Alberta (and characterized as "an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects"), and then evolves and improves the mechanism for use in an Ontario context.

27. EGD believes that the modified SEIM laid out in this proposal meets the objectives of the OEB:
    - Ties SEIM reward to ROE performance and provides the utility with an ongoing incentive to operate efficiently throughout the entire IR term
    - Includes stronger incentives for creating sustainable efficiencies, by removing a disincentive for productivity investment in later years of the IR plan
    - Creates the incentives in such a way that they relate directly to long-term, sustainable efficiencies that will provide benefit to customers
    - Provides a direct link to the OEB's objective for driving sustainable efficiencies during IR.

Witnesses: R. Fischer
S. Kancharla
M. Lister
A. Mandyam
P. Squires

RATE BASE EVIDENCE AND SUMMARIES

1. This evidence deals with information with respect to EGD's utility rate base and the levels of gross plant, accumulated depreciation and working capital elements within rate base.

2. The table found at Updated Exhibit B1, Tab 1, Schedule 2, is a summary showing the values on an average of average basis for each of these rate base components.

3. The 2014 fiscal year rate base of $4,431.6 million is higher by $269.6 million than the Board Approved 2013 rate base of $4,162.0 million. This increase is mainly due to property, plant and equipment costs and amounts closing into service offset partly by increases in accumulated depreciation along with an increase in the total required working capital. The increase in net property, plant and equipment of $193.8 million, is the result of the level of customer related capital amounts which close into service, an increased level of system improvement related capital requirements including the Ottawa reinforcement project closing into service in 2014 along with the impact of annual depreciation and increased accumulated depreciation which were partially reduced by the impact of the proposed reduction in certain distribution related asset depreciation rates. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $68.1 million to ratepayers in 2014 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $39.8 million due to the monthly pattern of the rate rider. The increase in working capital of $75.8 million is mainly the result of an anticipated increase in the value of gas in storage along with an increase in the required working cash allowance resulting from an increase in net working cash lag days and HST related working cash mostly from the increased level of capital spending.

4. The 2015 forecast year rate base of $4,797.6 million is higher by $366.0 million than the 2014 fiscal year rate base of $4,431.6 million. The increase in net property, plant and equipment of $346.4 million, is the result of a slightly higher customer related capital amounts, an increased level of system improvement related capital requirements including the GTA project closing into service in October 2015, the partial year impact of the WAMS project closing into service in December 2015, along with the impact of annual depreciation and increased accumulated depreciation. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $63.1 million to ratepayers in 2015 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $36.8 million due to the monthly pattern of the rate rider. Working capital also increased by $19.6 million over 2014 mainly the result of an anticipated increase in the value of gas in storage along with an increase in the required working cash allowance mostly as a result of anticipated increases in gas cost and HST related working cash from the increased level of capital related spending.

5. The 2016 forecast year rate base of $5,524.4 million is higher by $726.8 million than the 2015 forecast year rate base of $4,797.6 million. The increase in net property, plant and equipment of $750.1 million, is the result of a slightly higher customer related capital amounts, the full year 2016 rate base impacts of the previous year's GTA and WAMS projects which closed into service late in 2015 along with the impact of annual depreciation and increased accumulated depreciation. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $58.1 million to ratepayers in 2016 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $33.9 million due to the

monthly pattern of the rate rider. Working capital decreased by $23.3 million compared to 2015 mainly the result of an anticipated decrease in the value of gas in storage along with a decrease in the required working cash allowance mostly as a result of an anticipated decrease in HST related working cash from the decreased level of capital related spending.

6. The 2017 forecast year rate base of $5,736.6 million is higher by $212.2 million than the 2016 forecast year rate base of $5,524.4 million. The increase in net property, plant and equipment of $212.3 million, has been derived by using the 2016 forecast year amounts of capital spend and amounts closing into service as being a reasonable estimate of amounts which would affect the forecast 2017 property, plant and equipment. As explained in evidence at Exhibit A2, Tab 1, Schedule 1, the 2016 forecast customer additions have been assumed to be a reasonable estimate to be used in 2017 and as a result the capital expenditure related impacts have been assumed to be mostly the same as 2016. However, amounts forecast to be closing into service in 2016 in relation to the WAMS project, $8 million, have been removed from the capital related amounts used to calculate the 2017 net property, plant and equipment and rate base. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $53.1 million to ratepayers in 2017 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $31.0 million due to the monthly pattern of the rate rider. Working capital elements have been assumed to remain at the same level in 2017 as forecast in 2016 other than a slight change to working cash resulting from the forecast change in O&M which is an element contained within the working cash calculation.

7. The 2018 forecast year rate base of $5,906.1 million is higher by $169.5 million than the 2017 forecast year rate base of $5,736.6 million. The increase in net property, plant and equipment of $169.6 million, has been derived by using the 2016 forecast year amounts of capital spend and amounts closing into service as being a reasonable estimate of amounts which would affect the forecast 2018 property, plant and equipment. The adjusted estimated amounts of 2017 capital expenditure related impacts have been assumed to be a reasonable estimate to be used in 2018 to calculate the 2018 net property, plant and equipment and rate base. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $17.4 million to ratepayers in 2018 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $10.1 million due to the monthly pattern of the rate rider. Working capital elements have been assumed to remain at the same level in 2018 as estimated in 2017 other than a slight change to working cash resulting from the forecast change in O&M which is an element contained within the working cash calculation.

8. Details and explanations of 2014 through 2018 budgeted capital expenditures can be found in Updated Exhibit B2, Tab 1, Schedule 1.

9. Continuity schedules for gross property, plant and equipment, accumulated depreciation and working capital related elements can be found in Exhibits B3, B4, B5, B6 and B7, Tab 1, Schedules 1, 2 & 3.

Witness: K. Culbert

UTILITY RATE BASE (INCLUDING CIS & CUSTOMER CARE)
YEAR TO YEAR SUMMARY

Line No.		Col. 1 2013 Board Approved	Col. 2 2014 Fiscal Year	Col. 3 2015 Fiscal Year	Col. 4 2016 Fiscal Year	Col. 5 2017 Fiscal Year	Col. 6 2018 Fiscal Year
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment						
1.	Cost or redetermined value	6,749.4	7,104.1	7,568.1	8,449.0	8,813.7	9,169.3
2.	Accumulated depreciation	(2,804.1)	(2,965.0)	(3,082.6)	(3,213.4)	(3,365.8)	(3,551.8)
3.		3,945.3	4,139.1	4,485.5	5,235.6	5,447.9	5,617.5
	Allowance for Working Capital						
4.	Accounts receivable rebillable projects	1.3	1.3	1.3	1.4	1.4	1.4
5.	Materials and supplies	31.9	32.8	33.7	34.6	34.6	34.6
6.	Mortgages receivable	0.2	0.1	0.1	-	-	-
7.	Customer security deposits	(68.7)	(65.7)	(65.1)	(64.6)	(64.6)	(64.6)
8.	Prepaid expenses	1.8	0.9	0.9	1.0	1.0	1.0
9.	Gas in storage	248.4	279.9	291.2	276.3	276.3	276.3
10.	Working cash allowance	1.8	43.2	50.0	40.1	40.0	39.9
11.	Total Working Capital	216.7	292.5	312.1	288.8	288.7	288.6
12.	Utility Rate Base	4,162.0	4,431.6	4,797.6	5,524.4	5,736.6	5,906.1

2014 to 2018 CAPITAL BUDGET OVERVIEW

1. The purpose of this evidence is to provide the Ontario Energy Board (the "Board", or the "OEB") with an Overview of Enbridge Gas Distribution's ("Enbridge", "EGD" or the Company") detailed Capital Budget for the years from 2014 to 2016. As described in Exhibit A2-1-1, the Company has used its 2016 Capital Budget as the basis for forecasting its spending requirements for each of 2016, 2017 and 2018. While details of the components of the Capital Budget are found in the balance of the B2 series of exhibits, this Overview sets out how and why the Company has chosen to set out details of a three year Capital Budget and explains the main components of the Capital Budget.

2. The Company's forecast capital expenditures for 2014 to 2016 have been identified as the outcome of a lengthy budgeting process that commenced with the Board approval of the 2013 rates case settlement (EB-2011-0354), followed by a lengthy Company process to identify, evaluate and determine its capital spending needs in coming years. The budgeting process has ensured that Enbridge's 2014 to 2016 Capital Budget reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. The 2016 Capital Budget reflects the level of spending required in 2016, and a base level of spending in 2017 and 2018.

3. What has become clear through the budgeting process is that the Company's necessary level of capital spending is higher than in past years, and the spending requirements become unacceptably unpredictable when one looks out further than three years. As explained in Exhibit A2-1-1, it is this combination of high capital spending requirements and uncertainty in the longer term that have driven Enbridge to request approval of its Customized IR plan.

Witnesses: J. Sanders
P. Squires

4. The Company's Capital Budget forecast for 2014 to 2016 indicates required capital expenditures of $682.3 million in 2014, $832.0 million in 2015 and $450.0 million in 2016. These budgets are substantially higher than prior year budgets. There are two main reasons for this. First, there are very high levels of spending associated with three major projects which the Company must undertake in the next three years. Second, there are substantial cost pressures associated with a higher level of required System Integrity and Reliability spending.

5. This Overview evidence sets out the main components of the 2014 to 2018 Capital Budget, including the process used to arrive at that budget, under the following topic headings:

   A. A summary of Enbridge's forecast capital expenditures over the period of 2014 to 2016,

   B. An explanation of the main drivers of the Capital Budget for 2014 to 2016,

   C. A description of the budgeting process that identified the necessary expenditures that form the Capital Budget,

   D. Explanation of the outcomes from the Capital Budget process,

   E. Explanation of how management incorporated productivity in the proposed Capital Budget for 2014 to 2016,

   F. Explanation of year over year variances in the 2014 to 2016 Capital Budget, and

   G. Explanation of why and how the 2016 Capital Budget is used as the basis for the 2017 and 2018 Capital Budget.

A. Summary of the Capital Budget 2014 - 2016

6. Table 1 provides a summary view of the planned capital expenditures for the Company, totaling $682.3 million in 2014, $832.0 million in 2015 and $450.0 million in 2016. These amounts are categorized in a standard summary view of the Capital Budget, as provided in previous applications.

Table 1
Summary of Capital Expenditures

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

7. The Company will use the term “Core Capital” to include all capital spending, except for three identified major projects: the GTA and Ottawa Reinforcements and the Work and Asset Management Project (WAMS). The “Core Capital” term essentially captures the spending amounts that were included within the 2013 Board Approved Capital amount (after taking into account, as seen in Table 1 above, that there was $0.5M of initial WAMS project spending included within the 2013 Board Approved Capital amount).

Witnesses: J. Sanders
P. Squires

8. Table 2 provides a standard detailed schedule of the proposed Capital Budgets for 2014 to 2016, as compared to the 2013 Board approved Capital Budget amount of $386.6 Million.

Table 2

COMPARISON OF UTILITY CAPITAL EXPENDITURES
2013 BOARD APPROVED BUDGET AND 2014 -2016 FORECASTS
(EXPRESSED IN $MILLION)

Item No.		Col. 1 Board Approved Budget 2013	Col. 2 Forecast 2014	Col. 3 Forecast 2015	Col. 4 Forecast 2016
A.	Customer Related				
1.1.1	Sales Mains	44.6	39.6	42.1	49.1
1.1.2	Services	68.1	69.0	73.7	76.3
1.1.3	Meters and Regulation	10.3	10.4	11.0	11.7
1.1.4	Customer Related Distribution Plant	123.0	119.0	126.8	137.1
1.1.5	NGV Rental Equipment	0.3	3.4	3.6	3.7
1.1	TOTAL CUSTOMER RELATED CAPITAL	123.3	122.4	130.4	140.8
B.	System Improvements and Upgrades				
1.2.1	Mains - Relocations	27.5	28.6	24.9	26.0
1.2.2	- Replacement	71.0	105.6	94.2	82.5
1.2.3	- Reinforcement	27.0	21.3	31.6	18.1
1.2.4	Total Improvement Mains	125.5	155.5	150.7	126.6
1.2.5	Services - Relays	17.3	29.8	34.5	52.1
1.2.6	Regulators - Refits	9.7	9.8	10.0	10.1
1.2.7	Measurement and Regulation	24.3	31.5	34.1	32.6
1.2.8	Meters	16.0	16.6	18.5	20.8
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	192.8	243.2	247.8	242.2
C.	General and Other Plant				
1.3.1	Land, Structures and Improvements	7.8	12.9	11.2	6.8
1.3.2	Office Furniture and Equipment	1.6	4.6	4.7	4.4
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	4.8	4.6	4.7	4.7
1.3.4	Tools and Work Equipment	1.4	1.5	1.5	1.5
1.3.5	Computers and Communication Equipment	32.0	32.7	30.6	31.0
1.3	TOTAL GENERAL AND OTHER PLANT	47.6	56.3	52.7	48.4
D.	Underground Storage Plant	22.4	21.9	15.7	10.5
E.	SUBTOTAL "CORE" CAPITAL EXPENDITURES	386.1	443.8	446.6	441.9
F.	Work and Asset Management System (WAMS)	0.5	36.3	25.7	8.1
G.	SUBTOTAL CAPITAL EXPENDITURES	386.6	480.1	472.3	450.0
H.	Leave to Construct				
1.7.1	Ottawa Reinforcement	44.0	5.1	-	-
1.7.2	GTA Reinforcement	19.3	197.1	359.7	-
1.7	TOTAL LEAVE TO CONSTRUCT	63.3	202.2	359.7	0.0
I.	TOTAL CAPITAL EXPENDITURES	449.9	682.3	832.0	450.0

Witnesses: J. Sanders
P. Squires

9. The first step in the budget process that led to the 2014 to 2016 Capital Budget was the finalizing of the 2013 capital budget to match the necessary capital needs of the business to the 2013 Board approved settlement amount of $386.6 Million (note that the Ottawa and GTA Reinforcement projects were outside of the $386.6 Million amount). In conducting the 2013 budget process, the Company determined that the necessary business expenditures and costs for 2013 were greater than the Board approved settlement amount. The Company is not seeking any recoveries in the Customized IR plan proposal for the additional capital spending in 2013 (nor the spending above forecast levels in 2012). The Company expects to bring forth in the Rebasing Rates Application any amounts of additional Capital spend for 2012 and 2013.

10. Based on the learnings from the 2013 budgeting process, including the recognition of increasing spending requirements for safety and integrity projects, the Company undertook a “Capital Budget Refresh” process to understand its capital spending needs for the period 2014 to 2018. That process, which involved several iterations of scrutinizing and prioritizing proposed capital spending, ultimately resulted in the three year detailed Capital Budget.

11. As explained within the updated evidence in the A2 series of exhibits, Enbridge has used the 2016 Capital Budget to represent its 2017 and 2018 capital spending requirements within the Allowed Revenue amounts for 2017 and 2018. Enbridge has made this change to the Customized IR plan to address the expectation that the Company will set Allowed Revenue amounts for all five years of this Customized IR term in this proceeding, and not revisit capital spending requirements midway through the term. While Enbridge is not currently able to specifically forecast all elements of its 2017 and 2018 Capital Budget, the Company believes that the best overall forecast of its capital spending requirements during those years can be seen

in the 2016 Capital Budget. Although some of the detailed spending requirements will change each year, Enbridge expects that the overall capital spending requirements for 2017 and 2018 will be in line with 2016. The one change that Enbridge has made to the 2016 Capital Budget is that, for purposes of 2017 and 2018, the $8 million forecast spending on WAMS has been removed, since that project will have been completed. Therefore, the Capital Budget used for 2017 and 2018 is the same as set out in the "Forecast 2016" column within Tables 1 and 2 above, except that the $8.1 million associated with WAMS is removed, leaving a forecast Capital Budget of $441.9 million for each of 2017 and 2018.

12. Further details about the application of the 2016 Capital Budget to 2017 and 2018 are set out below, in section "G" of this evidence.

13. The Capital Budget as proposed for 2014 to 2016 reflects the continued application of the Company's capitalization policy. In EB-2011-0354, the Board approved Enbridge's continued use of that capitalization policy notwithstanding the transition to US GAAP accounting policies.

14. The proposed overall capital expenditures for 2014 to 2016 represent a significant increase from the 2013 Board Approved Capital amount. The majority of the increase in expenditures can be attributed to three business needs:

- First and most significant is the need for the GTA and Ottawa Reinforcement projects,
- Second, the need for investment in WAMS, and
- Third, is the need for a variety of new and increased work to address System Integrity and Reliability requirements of the Company's distribution

system. It is this need that is primarily driving the increase in Core Capital Spending.

15. Details about the high-level drivers of the Capital Budget for 2014 to 2016 are set out in the next section of this Overview.

B. Main Drivers of the Capital Budget For 2014 To 2016

16. The Capital Budget for 2014 to 2016 is driven by new and ongoing spending requirements. The ongoing requirements include the continuation of historic activities to: (i) maintain the distribution system (including storage), (ii) add new customers, and (iii) maintain the Company's other infrastructure (such as buildings and IT systems). The new requirements relate to: (i) Major Reinforcement projects in the GTA and Ottawa, (ii) a need to implement WAMS to provide primary work and asset management functionality and support the increasing amount of asset-related work, (iii) increasing System Integrity and Reliability work to address identified risks within the Company's distribution system, and (iv) the need to act on increasing relocation work (especially in 2014) that is driven by external third-party projects.

17. The following sections provide information on the main drivers of Enbridge's 2014 to 2016 Capital Budget. The balance of the B2 series of exhibits contains further details about the Company's individual business area capital budgets, including descriptions of projects of $2 million or more, that cumulate to form the overall 2014 to 2016 Capital Budget.

Continuation of Historic Activities and Costs (Business as Usual)

18. The Capital Budget for 2014 to 2016 include a continuation of historic activities that: (i) maintain the distribution system (including storage), (ii) add new customers, and (iii) maintain the Company's other infrastructure (such as buildings

and IT systems); and historic costs such as (iv) departmental labour costs, (v) Capital Overheads (Administrative and General), and (vi) Interest During Construction.

(i) maintain the distribution system (including storage)

19. Within the Capital Budget, the Company will continue to undertake activities that are "keeps the lights on" type of capital work. Examples of these activities that the Company will continue to perform are the code and regulation based Meter Exchange Government Inspection program and the spending on base maintenance activities in the Reinforcements and Relocations areas.

(ii) add new customers

20. From 2009 and 2012, Enbridge's annual customer additions rose from approximately 32,000 to 36,000 new customers per year. Enbridge forecasts this trend to continue for the next few years with the addition of new customers being approximately 38,000 in 2013, 36,500 in 2014, 38,500 in 2015 and 39,500 in 2016. The Capital Budget includes the costs to add the annual forecasted new customers.

(iii) maintain the Company's other infrastructure (such as buildings and IT systems)

21. The Capital Budget includes costs to maintain facilities in a safe state and replacing out of date or end of life IT systems through the period of 2014 to 2016. In finalizing the necessary spending proposed in the Capital Budget, the Company has decided to defer some facilities-related activities, such as replacing aging building facilities.

(iv) Departmental Labour Costs

22. Departmental labour costs are primarily the salaries and employee expenses for the departments within Engineering and Operations. The respective functions of these departments contribute to putting Core Capital activities (Mains, Services and Stations) into service. Examples of these functions include system capacity planning, distribution plant drafting, pipeline inspection, field operations, customer attachment and records management.

23. The Capital Budget process reviewed each department and assessed staffing needs for the period of 2014 to 2016. Overall, the Company expects to deliver its Core Capital spending without adding additional Departmental Labour costs. The costs going down from 2013 levels and being maintained below 2013 levels for the period of 2014 to 2016 reflects that the Company expects to replace staff that have left through natural attrition with staff that have lower salaries. Through the period of 2014 to 2016 management expects turnover of employees to be as much as 100 employees annually. By not adding departmental labour costs for base programs, the Company is committing to accommodating any additional work in these programs by finding efficiencies in operations between these departments.

24. The following Table 3 sets out the amounts of Departmental Costs from 2014 to 2016 and are included in Tables 1 and 2.

Table 3
Departmental Labour Costs 2013 - 2016
($,000)

		2013 Budget Capitalized Departmental Labour Costs	2014 Forecast Capitalized Departmental Labour Costs	2015 Forecast Capitalized Departmental Labour Costs	2016 Forecast Capitalized Departmental Labour Costs
B1-2-1	**Total Departmental Labour Expenditures**	**76,563**	**74,843**	**73,428**	**75,551**

Witnesses: J. Sanders
P. Squires

(v) Capital Overheads (Administrative and General Costs)

25. Capital Overheads are recognized as Administrative and General Costs (A&G) and are a function of Operations and Maintenance expenses. The A&G costs represent the common services that support capital activities. As per Board approved methodology, specific categories of Operations and Maintenance expense are capitalizable by applying specific percentages (i.e.: Human Resources, Information Technology and Corporate Departments).

26. A&G is charged to Distribution plant; Storage plant and IT asset classes and allocated to each area as a percentage of that areas cost to the total Distribution Plant, Storage Plant and IT costs. Capital Overheads increase slightly over the period of 2014 to 2016 from their 2013 Budget. The increase between 2014 and 2013 is reflective of the slight increase in Corporate Department expenses and the increases in 2015 and 2016 reflect the increases in O&M salaries and expenses. Capital Overheads represent approximately 8% of the annual Core Capital Budget.

27. The following Table 4 sets out the amounts of A&G amounts within the Capital Budget from 2014 to 2016 and are included in Tables 1 and 2.

Table 4
Capital Overheads (A&G) Costs 2013 - 2016
($,000)

		2013 Budget Capital Overheads (A&G)	2014 Forecast Capital Overheads (A&G)	2015 Forecast Capital Overheads (A&G)	2016 Forecast Capital Overheads (A&G)
B1-2-1	**Total Capital Overheads (A&G) Expenditures**	33,602	35,500	36,440	37,140

(vi) Interest During Construction

28. Interest During Construction (IDC) is the recoverable amount of interest that the Company must spend in order to fund its capital initiatives. The calculation of IDC

Witnesses: J. Sanders
P. Squires

is a function of work in progress balances. This is applicable to pipeline construction, storage plant construction and software applications that are in progress and not yet used or useful.

29. The following Table 5 sets out the amounts of IDC amounts within the Capital Budget from 2014 to 2016 and are included in Tables 1 and 2.

Table 5
Interest During Construction (IDC) Costs 2013 - 2016
($,000)

		2013 Budget Interest During Construction (IDC)	2014 Forecast Interest During Construction (IDC)	2015 Forecast Interest During Construction (IDC)	2016 Forecast Interest During Construction (IDC)
B1-2-1	**Total Interest During Construction (IDC) Expenditur**	**5,356**	**8,400**	**9,251**	**7,399**

30. The forecast costs of Departmental Labour, Capital Overheads (A&G) and IDC are included and allocated across the major accounts set out within Tables 1 and 2.

<u>GTA and Ottawa Reinforcements</u>

31. The proposed GTA and Ottawa Reinforcements address critical distribution infrastructure requirements in the Greater Toronto Area and Ottawa. The Company has outlined the needs and benefits of these projects in its Leave to Construct applications (EB-2012-0099 and EB-2012-0451).

32. The Ottawa Reinforcement project is intended to increase the capacity of the Ottawa area distribution system to meet existing and forecast loads as well as to provide additional security of supply and operational flexibility. The Ottawa Reinforcement project has been approved through the Board's Decision on the Leave To Construct application, issued on November 29, 2012.

33. The GTA Reinforcement project is intended to maintain system safety and reliability through enabling pressure reduction on several key pipelines in the Greater Toronto Area. The project is also intended to support diversification of supply. The GTA Reinforcement Leave To Construct application is currently being heard by the OEB.

34. The forecast costs of these Major Reinforcement projects are set out separately within Tables 1 and 2.

Work and Asset Management System (WAMS)

35. The proposed Work and Asset Management System (WAMS) is a requirement for the future operations of the Company servicing our customers. The WAMS project is fully described in Exhibit B2-6-2. The need for this project stems from technology drivers and the need to support primary work and asset management functions.

36. The primary driver is the coming end of the Accenture Services Agreement which was part of the EnVision Project that the Board approved in its 2004 decision of RP-2003-0203. The Company has decided that a more cost effective solution to the services approach that currently provides Work and Asset Management services would be to implement an in-house IT system. Timing is also driven by technology obsolescence of the decade old solution. It is also recognized in the industry that the area of asset management information systems has evolved substantively since 2004. WAMS will be the primary system for creating and tracking work requests and transactional asset information related to functions such as construction, maintenance, service, etc. Aligning asset related work with other work activities will provide an opportunity to package activities in an efficient

manner. An example of the packaged approach would be scheduling an AMP Fitting replacement to coincide with a leak survey or service relay.

37. Another driver is the need for the Company to meet more stringent safety and reliability standards, which necessitates more flexible information technology.

38. Finally, the WAMS project will support the proposed performance measurement tracking and reporting on productivity over the Customized IR Plan term, including productivity of outside partners.

39. These business drivers have established a priority for the Company to implement the WAMS Program. Over the next two years this project will source and implement technology that will enable Enbridge to continue to operate its core functions, and implement systems that complement the Company's holistic asset management approach.

40. The forecast costs of the WAMS project are set out separately within Tables 1 and 2.

System Integrity and Reliability Activities

41. The Company has identified that a continuation of increased activities and expenditures associated with System Integrity and Reliability is necessary for the period of 2014 to 2016 and beyond. The Company has also determined that the System Integrity and Reliability costs for 2017 and 2018 are uncertain, but very likely to be as much or more than the corresponding costs in 2016.

42. From November 1, 2012 the Company is obligated to implement and operate a fulsome program as a natural gas distributor in the province of Ontario. The increase in activity and expenditures for System Integrity and Reliability which led

to an increased level of spending starting in 2011 can be attributed to the following items:

- Recent Events: safety incidents at utilities in the United States
- Changes to regulations in both the United States and Ontario
- Enbridge's ongoing review of processes and decision criteria to maintain a safe distribution system

43. The focus on integrity management programs has been heightened as a result of safety incidents at natural gas utilities in the United States. One such event was the September 2010 San Bruno pipeline rupture and ignition in California. The event resulted in the death of eight individuals, the destruction of 38 homes, and injury to several additional individuals and damage to several other properties in the area.

44. As a result of the San Bruno incident, regulation, standards and legislative obligations for natural gas utilities in the United States were amended to be more stringent with respect to integrity management of distribution systems.

45. The November 1, 2012, the Technical Standards and Safety Authority ("TSSA") Code Adoption Document (FS-196-12) requires companies to produce an Integrity Management Program to maintain a safe and reliable Distribution System. This regulation includes the Document Amendment clause 12.10 (of the Canadian standards Association Z662):

> 12.10.16: Operating companies shall establish effective procedures for managing the integrity of pipeline systems with an MOP less than 30% of SYMS (Distribution Systems) so that they are suitable for continued service, in accordance with the applicable requirements of clause 3.2 of CSA Z662-11.

46. For Enbridge, this means that all of the operating distribution assets will now need to be included and managed within an effective System Integrity and Reliability set of activities. As per clause 3.2 of CSA Z662-11 Pipeline System Integrity Management Program, this program must assess potential risks, identify steps to reduce these risks and monitor the results of the risk reduction projects or program. As per clause 10.3.10 of TSSA's November 1, 2012 Oil and Gas Systems Code Adoption Document, the Integrity Management Program shall include:

- a management system;
- a working records management system;
- a condition monitoring program, and
- a mitigation program

47. Management has taken its responsibility under the recent TSSA code change and more stringent landscape in the United States as an important change to its legislated obligations and expectations on how it manages the distribution system. Management has interpreted the code change as a requirement to proactively assess risks, propose remediation, refurbishment and replacement of the distribution system, when and where necessary, to prevent system failures.

48. Within Enbridge's proposed Integrity Management program expenditures for 2014 to 2016, examples of management decisions include:
    A. the expenditures for In-Line Inspections ("ILI") of pipelines above 20% of the Specified Minimum Yield Stress ("SMYS") and the Maximum Operating Pressure ("MOP") Verification Program;

B. adopting a proactive replacement strategy towards replaceable technology such as Compression Couplings or AMP Fittings rather than monitoring their operation and replacing after the failures have occurred; and

C. replacing critical operating assets such as specific components of Gate and District Stations (up to and including the entire station) rather than extending the active use of these assets beyond the end of their useful life through the use of Operations and Maintenance budgeted activities.

49. As set out within the Asset Plan (filed at Exhibit B2, Tab 10, Schedule 1), the Company expects to continue these activities within 2017 and 2018.

Externally Initiated Capital Projects

50. A further driver of incremental capital spending requirements in the coming years is the expected increase in relocation requirements resulting from third-party infrastructure projects, such as transit and the Pan Am games.

51. The main driver for the proposed increase to these costs is projects from government organizations such as:

- the 2015 Pan American Games,
- Toronto Transit Commission (“TTC”), and
- MetroLinx

52. These externally driven infrastructure projects lead to requirements for pipeline replacements or relocations. While relocation activity is not new, the level of expected activity in the coming years is a substantial increase from past experience.

The forecast cost increases can be seen within the Mains-Relocations line at Table 2, above.

C. Capital Budgeting Process

53. To understand and evaluate the Company's Capital Budget, it is useful and informative to look at how the budget was created. As explained below, the lengthy and rigorous process that led to this Capital Budget has ensured that the budget is set at a level that reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. Savings attributable to productivity and efficiency initiatives are included within the Capital Budget amounts.

54. The Company commenced the capital budgeting process that led to the 2014 to 2016 Capital Budget in November of 2012. The first step in the process was to align the 2013 Board-Approved Capital Budget of $386.6 million with the Company's spending requirements for 2013. That step led to a realization that complete alignment was not possible, because spending requirements for 2013 exceed that level. However, for the purpose of this Application, Enbridge has set out its 2013 Capital Budget to align with the Board-Approved Capital Budget amount. As noted above, to the extent that Enbridge spends above that level, it will not seek recovery until its Rebasing Application.

55. Immediately after the 2013 Capital Budget was set, the Company proceeded with its "Budget Refresh" process to update its forecasts of capital spending for 2014 to 2018. This began with a "Bottom-Up" list of business needs, and then proceeded through several iterations where proposed projects and spending were presented to and scrutinized by management and direction was given to make changes to the Capital Budget. Through a lengthy iterative process, Enbridge arrived at a three

year Capital Budget for 2014 to 2016, having determined that capital expenditures for 2017 and 2018 were too speculative to be included.

Inputs to the Capital Budget

56. As noted, the capital budget process began with a "Bottom Up" list of capital spending requirements for 2014 to 2018. There were a number of inputs into the creation of this "grassroots" budget, as described below.

(i) Asset Plan

57. The Company's long range distribution system planning tool, the Asset Plan, provides a 10 year view into customer growth, potential reinforcements, system integrity and reliability requirements, relocation projects and major reinforcements. The Asset Plan represents an information vehicle for Enbridge management to use for future planning purposes. The 2013-2022 Asset Plan is filed at Exhibit B2, Tab 10, Schedule 1.

58. The Asset Plan is an ever-evolving document, to reflect the Company's most current understanding of its distribution assets. While the actual 2013-2022 Asset Plan document filed in this case was not completed at the time that the Capital Budget process began in late 2012, the updated identification of the Company's asset requirements (which forms the basis for much of the Asset Plan) had been completed by that time. That information was used as an input into the creation of the "Bottom Up" budgets used at the outset of the Capital Budget process.

(ii) GTA and Ottawa Reinforcement Projects and WAMS

59. The GTA and Ottawa Reinforcements and WAMS project had all been identified as necessary projects by the time that the Capital Budget process began. Each of these projects has been subject to separate budgeting processes, and the outputs

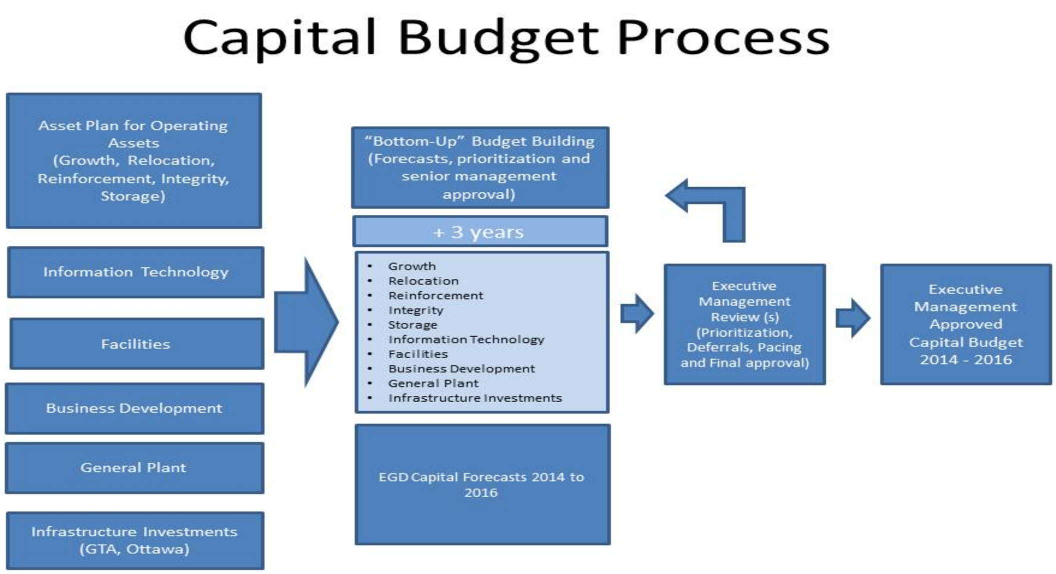
of those project specific reviews were used as inputs into the Capital Budget process.

(iii) All Other Inputs

60. The Asset Plan only addresses the Company's distribution asset requirements. Therefore, to determine the capital spending requirements for other aspects of the Company's operations, information was sought and received from additional capital business areas including Information Technology, Gas Storage, Business Development, Facilities and General Plant. That information was an input into the creation of the "Bottom Up" budgets used at the outset of the Capital Budget process.

Steps in the Capital Budget Process

61. Enbridge's Capital Budget for 2014 to 2016 was determined through a lengthy iterative process. Figure 1 below depicts the process flow undertaken by the Company to finalize its Capital Budgets.



62. The process commenced with departments such as Gas Storage, Information Technology, Facilities and Business Development providing their "Bottom-Up" capital needs. The Asset Plan was used as an input for the Operations and Planning, Integrity and Engineering departments "Bottom-Up" capital needs.

63. After the initial "Bottom-Up" Capital Budget was created, the Company proceeded with an intense process to scrutinize each proposed expenditure. The process was established as a Company priority and included all departments and associated capital decision makers. The objective was to define the amount of necessary capital expenditures required to ensure the utility meets its commitments to its customers and its regulators, including spending necessary to meet the growth, safety and operational requirements of the business. The ultimate goal of this exercise was to ensure that the capital expenditures within the Capital Budget were limited to the lowest prudent level.

64. A senior management committee ("Capital Owners Committee") made up of senior representatives of the operating groups within the Company, as well as Finance and Regulatory, conducted peer reviews and scrutinized the list of expenditures in each cycle of capital forecast. This resulted in changes to the budgets. For each cycle, the output of the Capital Owners Committee was then reviewed by Executive Management who made their own changes. The Executive Management team was made up of Enbridge's President and Vice Presidents.

65. The Capital Budget process went through six review cycles, culminating in Executive Management approval of the final 2014 to 2016 Capital Budget. Table 3 sets out the timing at which each review cycle was completed.

Table 6

Capital Budget Process Milestone Dates

Date	Iteration
November 1, 2012	2013 Budget Setting Start Date
January 8, 2013	2014 to 2018 Budget Setting Start Date
January 18, 2013	REVIEW 1
February 15, 2013	REVIEW 2
March 22, 2013	REVIEW 3
April 2, 2013	REVIEW 4
April 18, 2013	REVIEW 5
May 21, 2013	REVIEW 6 and Final Capital Budget 2014 – 2016

66. After the first review, it was recognized that many of the System Integrity and Reliability expenditures (along with some other items) had forecasts that were of a variable or uncertain nature. Analysis of the first review showed that the proposed spending pattern was forecasting System Integrity and Reliability activity costs that may not materialize as outcomes of the activity.

67. Executive Management requested a further segmentation of each capital forecast to identify the magnitude of the costs that were certain to be spent and those that were outcome based and therefore difficult to forecast. Each capital expenditure from Review 2 onward was broken out into Variable and Firm costs. The Firm costs category captured costs that were certain and the Variable category represented costs that may or may not materialize, largely based on the outcomes of studies and execution of certain System Integrity and Reliability programs. The Capital Budget Process retained this additional categorization through the remainder of the review cycles.

68. Through the budget review process, the Capital Owners Committee applied a number of criteria to prioritize proposed spending, and determine what items should be retained within each successive version of the Capital Budget, and which items could be altered or removed. The criteria that were applied included the following:

- *Priority*: to identify the need for particular spending within a given year. An example of a change in priority was the decision to delay the Don River Replacement project that is identified in the Asset Plan. Another example is evident in the Facilities budget which had proposed a building expansion to the Company's Kennedy Road facility to accommodate staff who are currently being housed in "portables" in the parking lot.

The final decision of the budget process was to reject building expansion and keep the additional staff in portables.

- *Probability of Spend Occurring*: High, Medium, Low. High Probability ratings were given where there was an 80% to 100% probability of the spend occurring in that year. A Medium Probability rating indicated a 50% to 80% chance and a Low Probability ranking represented a 0% to 50% chance of the project put in service that year. Items of Low Probability are not included within the Capital Budget for a given year, and items of a Medium Probability may have their spending profile changed.

- *Timing of Need*: to determine whether the pacing of the spending can be changed. An example is the Load Shed Program that the Company will continue to undertake in 2014 to 2016. The program adds valves and other assets required to establish isolatable geographic zones within the distribution system. These isolatable zones when established enable the Company to preserve supply to specific customers while neighbouring customers may have their gas supply shut-off in the event of an incident or other business requirement. Through the budget process, a decision was made to slow the pace of implementing the Load Shed Program to a range of 10 to 15 years rather than one of 5 to 10 years. This decision on Timing of Need was based on information that indicated that a longer period of implementation would not adversely increase the risk to Customers being supplied with natural gas.

- *Alternative to Need*: Review of other choices including O&M maintenance. For example, under the System Integrity and Reliability activities, Gate Stations Program, the Gas Preheat System Risk Mitigation project conducted several alternatives to need analysis. The proposed program includes the removal, replacement and testing of the oldest heat exchanger in the system. It also includes the retrofit of the next two oldest heat exchangers with actuated valves on the heat exchanger and glycol loop of the preheat system. Alternatives that were examined included doing nothing, replacing all heat exchangers, just replacing the oldest heat exchangers.

- *Financial Analysis*: Review of Capital and O&M cost interaction, historical trends where applicable, unit cost rates etc. An example was confirmation of a decision to install remote electronic pressure sensing devices to paper chart recorders and provide real-time pressure information to a central control centre. The capital costs of this initiative were confirmed to be less than the expected long-term O&M savings arising from no longer having to operate paper chart recorders and maintain and interpret the paper charts that had been produced.

- *Productivity*: Where applicable, incorporate actions to "get more work for same unit cost". An example is the proposed capital budget for Customer Related work which shows reductions in the cost to add new customers. This is a result of a determination that the Company can find ways to save money in its actual average cost to add a new customer, as compared to those costs in 2012. Further discussion of the productivity savings within the 2014 to 2016 Capital Budget is set out below.

- *Firm vs. Variable*: as described above.

69. These criteria allowed evaluation of each expenditure by several angles. The multiple angles of examination confirmed to management that the final proposed expenditure represented the lowest reasonable cost for the necessary activity.

70. The final Capital Budget review cycles examined the proposed capital expenditures by year, applying the criteria above to evaluate each capital expenditure. Executive Management provided direction and decisions through each review cycle and continued until they were fully satisfied that the Capital Budget had reached the lowest prudent level.

D. <u>Results of the Capital Budget Process</u>

71. There were three main outputs from the Capital Budget Process.

72. First, the identification of capital spending requirements in excess of historical levels led Enbridge to determine that it required a different IR plan from its 1st Generation IR plan. The discussion of why an "I-X" model is not appropriate is set out in a number of places within the A2 series of exhibits.

73. Second, the identification of a large amount of uncertain spending, especially in the years beyond 2016, led Enbridge to determine that it could only create a three year Capital Budget at this time. This led to the Customized IR plan as originally filed.

74. Third, the key output from the Capital Budget Process was the creation of a three year budget that reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. Through the rigour of the Capital Budget Process, more than $180 million was removed from the originally submitted "Bottom Up" grassroots budgets.

Decision to Proceed with a Three Year Capital Budget

75. The Company had gone through three Capital Budget Review cycles at which time a decision was made to change the budgeting time frame from a five year period ending in 2018 to a three year period of 2014 to 2016.

76. At a high level, the key information that drove the reduction in the term from five years to three years was the significant variability in capital forecasts after 2016. The variability was being driven by two primary issues: (i) uncertainty with System Integrity and Reliability program outcomes; and (ii) uncertainty with externally initiated projects. The amounts in the capital budget forecasts had variability in the range of $50 to $100 million per year of additional capital costs.

77. The decision to create a three year budget was seen to be consistent with the fact that the Company's capital spending requirements over the 2014 to 2016 period will be quite different from future years, because of the need for several major projects (GTA and Ottawa Reinforcement and WAMS) over the next three years.

78. Details of each of these items that contributed to the decision to proceed with a three year Capital Budget are set out below.

(i) Uncertainty with System Integrity and Reliability program outcomes

79. There are three main causes for the variability in the System Integrity and Reliability program cost forecasts. One is the fact that the scope and requirements of many of the System Integrity and Reliability programs will not be fully known until related studies are completed and there is some practical experience with the programs. The second is the fact that the Company anticipates more stringent Pipeline Integrity Management legislation, such as that contemplated in the United States,

but does not know when this will be implemented. The third is the continue evaluation on the Companies assessment of risk to the distribution system through the asset planning process. Future risk assessment will change the risks identified and the priorities of these risks.

80. Through the first two reviews of the Capital Budget, it had become clear that capital cost requirements for a five year period were hard to quantify with any specificity. Depending on the outcomes of System Integrity and Reliability studies, and the outcomes from early experience with new System Integrity and Reliability programs, the costs would vary. While there is uncertainty about the level of required costs even within a one year timeframe, the amount of the potential variance becomes unacceptably high when one forecasts five years into the future.

81. Examples of the variability in the System Integrity and Reliability cost forecasts are seen in the potential engineering outcomes of the MOP Verification Program, the In-Line Inspection Programs and the Process Hazard Assesment (“PHA”) of the Gate and District Stations. The MOP and ILI Programs will identify segments of the distribution system that require replacing. However, the outputs of the inspection programs could identify a greater number of kilometres of pipeline or additional reinforcements than budgeted. The variability in length of pipeline replacement or predicting potential reinforcement projects has created a large swing in the Company’s ability to firmly forecast capital expenditures. Similarly, the PHA’s could yield a range of outcomes from minor component replacements to entire station replacements and/or relocations.

82. The uncertainty and variability in cost forecasts led the Company to determine that it could only create a dependable Capital Budget forecast for three future years, rather than five. At the same time, though, the Company also recognized that it may not be appropriate to include its uncertain (or potential) costs within the Capital

Budget being presented to support its Customized IR application. The solution that was reached was to identify that group of costs for each year, but not to include those costs, which are referred to as "variable costs" throughout this document, within the filed 2014 to 2016 Capital Budget. For example, Enbridge decided to implement a budget for the MOP program that would include the project costs for inspection and assessment (the "firm" costs), but not include any capital amounts for replacement of pipeline (the "variable" costs). The same approach has been taken for the ILI program.

83. The result is that Enbridge will be at risk for the "variable" costs associated with the System Integrity and Reliability studies and programs (as well as variable costs associated with other capital spending projects). The Company expects that at least some of the identified "variable" costs will materialize, so this is a real risk that will have to be accommodated by finding further efficiencies within the rest of the Company's operations. This was one of the items driving Enbridge to a three year Capital Budget (2014 to 2016). The Company has been very uncomfortable with shouldering the risk associated with these "variable" costs for more than three years. At this time, though, as described below in section G, Enbridge has determined that it is prepared to continue to take these risks for 2017 and 2018, by using the 2016 Capital Budget as the basis for forecasts of 2017 and 2018 capital spending. However, to address two of the most real risks which are outside of Enbridge's control, there will be variance account treatment for 2017 and 2018 capital costs related to relocations and to pipeline replacements required because of issues discovered through pipeline inspections (such as, but not limited to, the ILI and MOP programs).

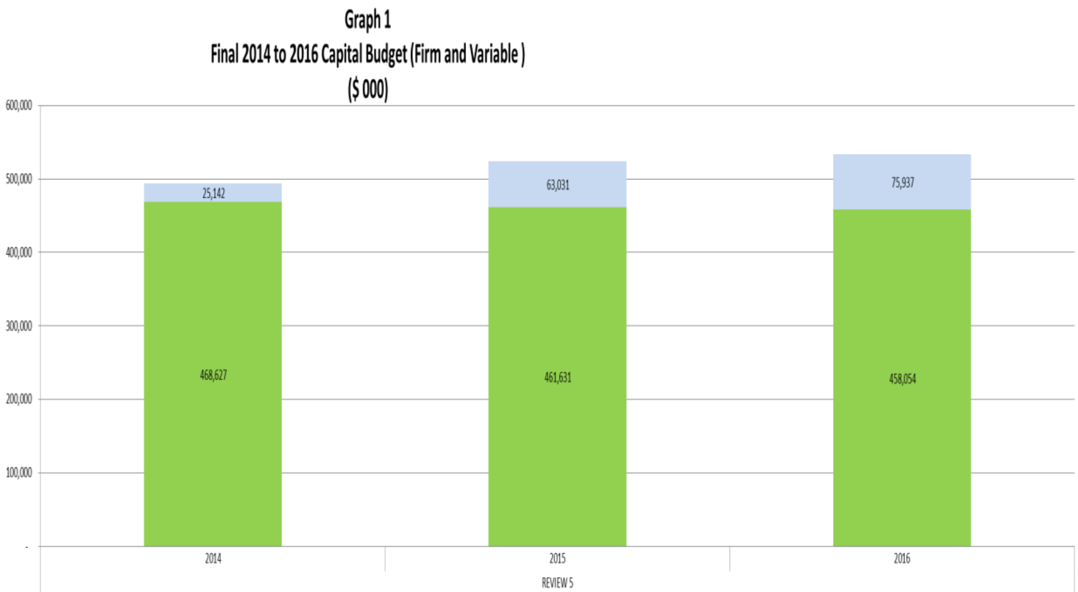
84. Table 7, below, sets out the "firm" and "variable" budget amounts associated with System Integrity and Reliability studies and programs over the 2014 to 2016 term.

The total forecast of "firm" amounts is approximately $94 million, while the total forecast of "variable" amounts is approximately $116 Million. Stated differently, for the period of 2014 to 2016 the System Integrity and Reliability studies and programs have a potential "variable" spend that is approximately 108% of the budgeted "firm" amounts that are included within the Capital Budget.

Table 7
System Integrity and Reliability List of Firm and Variable Forecasts
(Thousands)

Project Name or Blanket Program	Firm 2014	Firm 2015	Firm 2016	Variable 2014	Variable 2015	Variable 2016
AMP Fitting Replacement	8,543	13,100	30,046	-	13,814	13,694
Bare Steel Drips (study & removal program)	255	-	-		2,335	2,289
Bare Steel Service Replacement						208
Casing Study & Program	510	-	-		531	520
EFV Program	500	604	733	2,254	1,432	1,405
Failure of Bonnet Bolts on Valves Study					212	
ILI for pipelines over 20% SMYS plus HCA	4,000	4,080	4,162	6,200	6,450	6,324
Isolated Steel Mains CP Program	82	-	-		85	83
Load Shed Zone	1,145	1,171	1,194		1,194	1,170
Low Pressure Delivery Meter Set Program	1,530	2,341	2,388	1,530	2,387	2,341
Meter boxes				179	186	182
Plastic Mains (incl Services) Study					11,143	10,925
Remote Control Valve Study & Installation	565	602	680		3,979	3,901
Targeted Compression Couplings Pressure Contair	1,622	2,040	2,061		1,061	1,041
Verification of MAOP	3,296	3,397	3,195	5,304	4,881	4,786
WingLock Valve Study & Replacement	204	-	-		849	832
Totals	22,251	27,335	44,459	15,467	50,539	49,701

85. Beyond the System Integrity and Reliability studies and programs, there are other items within Enbridge's 2014 to 2016 Capital Budget which have associated "variable" costs. Graph 1 shows the total amounts of additional capital costs that could arise between 2014 and 2016 but which have not been included in the Capital Budget (the "variable" costs). These "variable" costs total more than $160 million over three years, and increase each year from 2014 to 2016. Enbridge is accepting the risk that some of these costs will likely arise, and will have to be accommodated.



	2014	2015	2016
Variable	25,142	63,031	75,937
Firm	468,627	461,631	458,054

(ii) Externally Initiated Projects

86. Another source of budget uncertainty relates to capital projects required to accommodate works being undertaken by Municipal and Provincial governments and organizations. Examples are large-scale transit projects and other infrastructure projects. These projects often require Enbridge to relocate or change distribution assets to accommodate construction activities.

87. Enbridge has found it challenging to forecast relocation requirements beyond the next few years, because details of transit and other infrastructure projects remain fluid. At the same time, though, the Company recognizes that the associated costs may be substantial. This has contributed to the difficulty of creating reliable five year Capital Budget forecasts.

(iii) Large Complex Projects over the Next Three Years

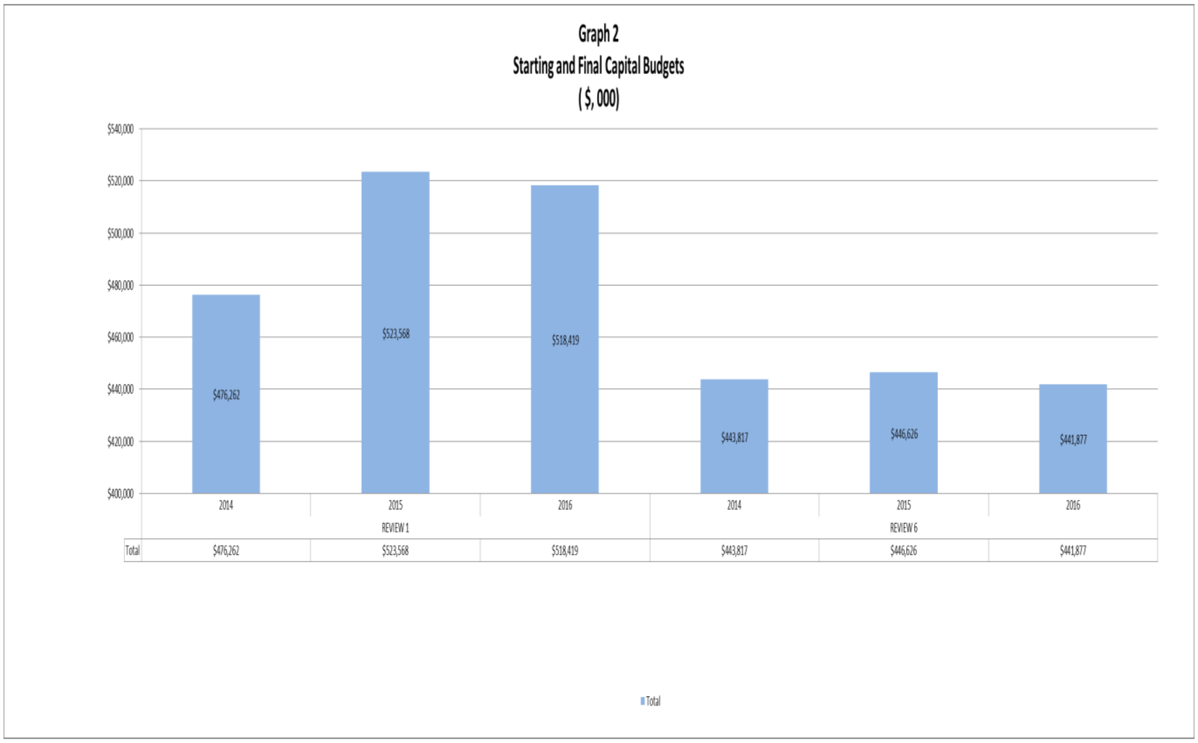
88. Enbridge determined that the use of a three year Capital Budget is consistent with the fact that the Company's capital spending requirements over the 2014 to 2016 period will be quite different from future years. The coming years are unusual because the majority of the Capital Budget increase arises from large complex capital projects that are contained within the 2014 to 2016 term (the GTA and Ottawa Reinforcements and WAMS project).

89. The Capital Budget process confirmed to the Company that the significant capital spending increase over the next three years is not a "business as usual" occurrence. Rather, this is an extraordinary period in Enbridge's history. Therefore, the Company concluded that a Capital Budget term of three years was the prudent approach to focus the utility on completing the large complex projects and to protect all parties from the consequences of presenting uncertain costs within the Company's filed budgets. At the same time, though, because the Company is taking the risk of uncertain "variable" capital costs, this approach will ensure focus on cost effectiveness.

The 2014 to 2016 Capital Budget

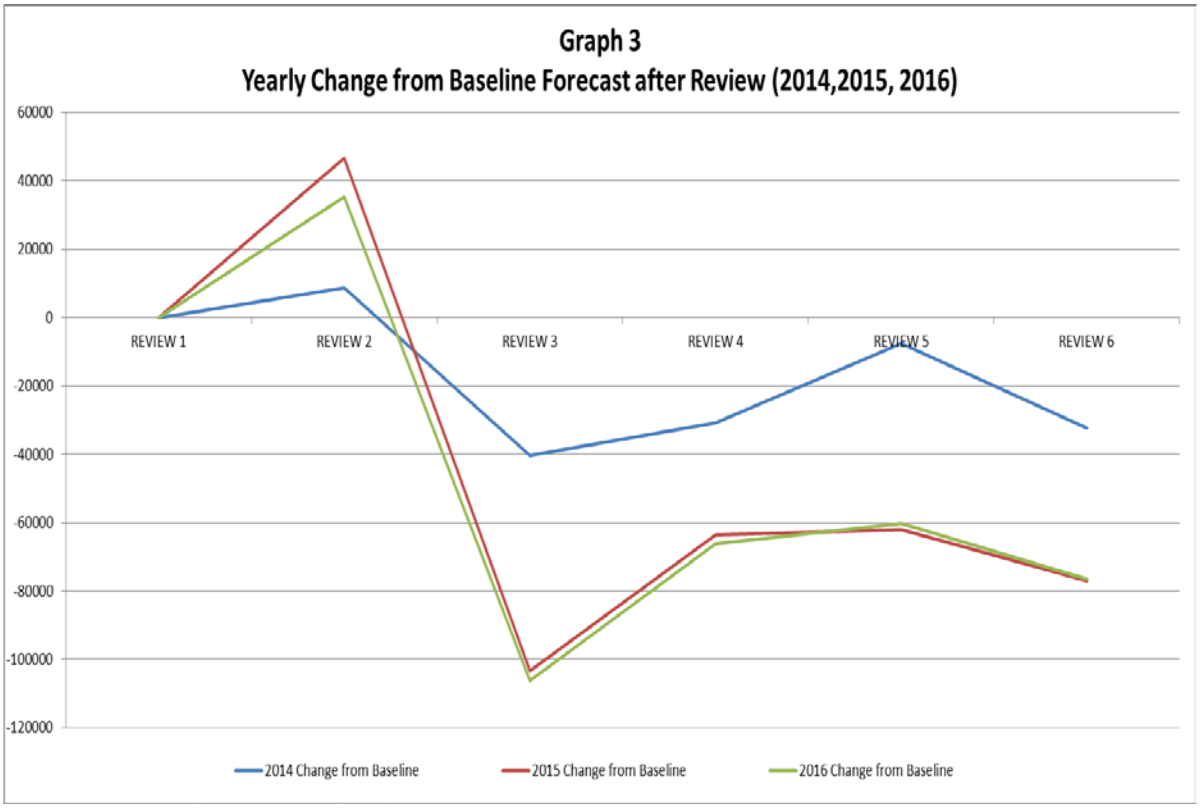
90. The 2014 to 2016 Capital Budget that resulted from the budget process is set out at Tables 1 and 2 above. From the start to end, the rigorous examination by the Capital Owners Committee and Executive Management of proposed capital budgets resulted in total reductions of approximately $185 Million for the three years or approximately 12.25% reduction from Review 1 to final approval. The annual reductions are approximately $32 Million, $76 Million and $77 Million for each year of 2014 to 2016. These annual amounts represent reductions of 6.8% in 2014, 14.7% in 2015 and 14.8% in the 2016.

91. The graph below shows the change from the opening capital forecast the final capital forecast as a result of the Capital Budget Refresh Process.



92. Given that the budgets related to the major projects were mostly unchanged from the outset of the budget review process, the changes that were made to the 2014 to 2016 Capital Budget mostly related to Core Capital amounts. The following graph sets out the Core Capital budget difference relative to the first budget after each review.

Witnesses: J. Sanders
P. Squires



93. Much of the change to the Core Capital amounts arose from the re-categorization of forecast costs as “variable”. As explained above, these costs are no longer included within the 2014 to 2016 Capital Budget; however, the Company expects that it will have to accommodate at least some of the costs. The following Table sets out the manner in which the Company’s categorization of “fixed” and “variable” costs evolved through the budget process.

Table 8

Yearly Change From Baseline After Each Review
($ 000)

REVIEW CYCLE	Sum of Firm 2014	Sum of Variable 2014	Sum of Firm 2015	Sum of Variable 2015	Sum of Firm 2016	Sum of Variable 2016
REVIEW 1	$ 476,262		$ 523,568		$ 518,419	
REVIEW 2	$ 485,010		$ 570,313		$ 553,820	
REVIEW 3	$ 435,739	$ 120,642	$ 420,039	$ 45,996	$ 411,591	$ 108,477
REVIEW 4	$ 445,509	$ 36,476	$ 459,964	$ 80,967	$ 452,251	$ 68,317
REVIEW 5	$ 468,627	$ 25,142	$ 461,631	$ 63,031	$ 458,054	$ 75,937
REVIEW 6	$ 443,817	$ 25,142	$ 446,626	$ 63,031	$ 441,877	$ 75,937

E. Incorporation of Productivity in the Capital Budget

94. Throughout the Capital Budget process, the Company worked to ensure that the Capital Budget amounts included cost savings due to efficiency and productivity. The following section outlines some examples of productivity initiatives incorporated in the proposed Capital Budgets for 2014 to 2016.

Departmental Labour Costs Productivity

95. As explained in the O&M evidence (for example, at Exhibit D1-3-1), the Company has resolved to maintain its overall FTE level (number of employees) flat through the 2014 to 2016 period. Executive management has determined that with a focus on efficiencies, the Core Capital programs (which are increasing to accommodate customer growth and System Integrity and Reliability programs) will be delivered within the existing FTE numbers.

96. One way of quantifying the productivity savings is to compare the departmental labour cost amounts within the 2014 to 2016 Capital Budget to the amounts that would be included using a 2% inflation rate from the 2013 levels.

Using that measure, there is a savings of approximately $14.98 million over the 2014 to 2016 term, as seen in the following table.

Table 9 Departmental Labour Cost Productivity ($ 000)						
		2013 Budget	2014 Forecast	2015 Forecast	2016 Forecast	Total Productivity Savings
Management Approved Departmental Labour Cost Forecasts		$ 76.50	$ 74.84	$ 73.43	$ 75.55	
2013 Budgeted Departmental Labour Cost Increased by Inflation @ 2 %		$ 76.50	$ 78.03	$ 79.59	$ 81.18	
Productivity amount Forecast vs 2013 @2% Inflation		**$ -**	**$ 3.19**	**$ 6.16**	**$ 5.63**	**$ 14.98**

97. To the extent that additional FTEs are needed to accomplish work, (such that the assumption of no staff additions cannot be maintained), Enbridge will accommodate the associated costs within other parts of the Capital Budget. Enbridge is committed to finding efficiencies needed to make this work.

<u>Productivity to Accommodate “Variable” Costs</u>

98. As explained above, the Company has determined that there are large amounts of uncertain or “variable” costs that may arise over the 2014 to 2016 term, primarily through the delivery of the System Integrity and Reliability initiatives. Those “variable” costs, which total more than $160 million, are not included within the Capital Budget.

99. 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. The result will be a requirement to find further productivity and efficiency gains, to allow for all necessary work to be completed.

F. Year over Year Variance Explanations

100. The 2014 to 2016 Capital Budget is set out at Tables 1 and 2 above. Part B of this Evidence described the main drivers of the overall budget during the 2014 to 2016 term. Set out below are high-level explanations of the year-to-year changes in the Capital Budget.

Major Changes: 2014 Capital Budget vs. 2013 Board Approved Budget

101. The 2014 Forecast is $682.3 million, which is $232.4 million or 51.6% over the 2013 Board Approved Budget of $449.9 million. Capital expenditure net increases in the 2014 Forecast are primarily driven by the requirements of three multi-year major initiatives; the GTA Reinforcement project, the Ottawa Reinforcement project and the Work and Asset Management System ("WAMS") project and an increase in System Improvement and Upgrades. The requirements of the three major projects contribute to $175.2 million of the variance, System Improvement and Upgrades accounts for $50.4 million of the variance and General and Other Plant needs increased by $8.2 million. The increase is partially offset by a $4.0 million decrease in the Customer Related (adding a new customer) requirements.

102. Table 10 below itemizes the major variances and the related evidence.

Table 10

2014 Forecast vs. 2013 Board Approved Budget Major Variance

2014 Test Year Budget vs 2013 Board Approved Budget ($Millions)	Over/(under)	Related Capital Evidence by Business Area
Customer Related Distribution Plant	(4.0)	B2-2-1 Customer Growth and B2-10-1 Asset Plan
NGV Rental Equipment	3.1	B2-7-1 Business Development
System Improvements and Upgrades	50.4	B2-3-1 Reinforcements, B2-4-1/5-1 Relocations/Integrity and B2-10-1 Asset Plan
General and Other Plant	8.7	B2-9-1 Facilities and General Plant, B2-8-1 Information Technology
Underground Storage Plant	(0.5)	B2-6-1 Underground Storage
"Core" Capital Requirements	**57.7**	
Work and Asset Management System (WAMS)	35.8	B2-8-2 Work and Asset Management
Leave to Construct Projects	138.9	B2-3-2 Major Reinforcements
Total Capital Expenditures	**232.4**	

Major Changes: 2015 Capital Budget vs. 2014 Capital Budget

103. The 2015 Forecast is $832.0 million, which is $149.7million or 21.9% over the 2014 Fiscal Year Budget of $682.3million. Capital expenditure net increases in the 2015 Forecast are primarily driven by the requirements of three multi-year major initiatives; the GTA Reinforcement project, the Ottawa Reinforcement project and the Work and Asset Management System (WAMS) project. The requirements of these three projects contribute to $146.9 million of the variance. The increase is partially offset by a $2.8 million decrease in the Core Capital requirements.

104. Table 11 below itemizes the major variances and the related evidence.

Witnesses: J. Sanders
P. Squires

Table 11

2015 Forecast vs. 2014 Forecast Major Variance

2015 Forecast vs 2014 Test Year Budget ($Millions)	Over/(under)	Related Capital Evidence by Business Area
Customer Related Distribution Plant	7.8	B2-2-1 Customer Growth and B2-10-1 Asset Plan
NGV Rental Equipment	0.2	
System Improvements and Upgrades	4.6	B2-3-1 Reinforcements, B2-4-1/5-1 Relocations/Integrity and B2-10-1 Asset Plan
General and Other Plant	(3.6)	B2-9-1 Facilities and General Plant, B2-8-1 Information Technology
Underground Storage Plant	(6.2)	B2-6-1 Underground Storage
"Core" Capital Requirements	**2.8**	
Work and Asset Management System (WAMS)	(10.6)	B2-8-2 Work and Asset Management
Leave to Construct Projects	157.5	B2-3-2 Major Reinforcements
Total Capital Expenditures	**149.7**	

Major Changes: 2016 Capital Budget vs. 2015 Capital Budget

105. The 2016 Forecast is $450.0 million, which is $382.0 million or 45.9% under the 2015 Forecast of $832.0 million. Capital expenditure decreases in the 2016 Forecast are primarily driven by the completion of two multi-year major initiatives; the GTA Reinforcement project and the Work and Asset Management System (WAMS) project. The completion of these two projects contributes to $377.3 million of the variance. The remaining $4.7 million decrease reflects fluctuations in the Core Capital requirements.

106. Table 12 below itemizes the major variances and the related evidence.

Witnesses: J. Sanders
P. Squires

Table 12

2016 Forecast vs. 2015 Forecast Major Variance

2016 Forecast vs 2015 Forecast ($Millions)	Over/(under)	Related Capital Evidence by Business Area
Customer Related Distribution Plant	10.3	B2-2-1 Customer Growth and B2-10-1 Asset Plan
NGV Rental Equipment	0.1	
System Improvements and Upgrades	(5.6)	B2-3-1 Reinforcements, B2-4-1/5-1 Relocations/Integrity and B2-10-1 Asset Plan
General and Other Plant	(4.3)	B2-9-1 Facilities and General Plant, B2-8-1 Information Technology
Underground Storage Plant	(5.2)	B2-6-1 Underground Storage
"Core" Capital Requirements	**(4.7)**	
Work and Asset Management System (WAMS)	(17.6)	B2-8-2 Work and Asset Management
Leave to Construct Projects	(359.7)	B2-3-2 Major Reinforcements
Total Capital Expenditures	**(382.0)**	

G. 2017 and 2018 Capital Budget

107. As explained above, Enbridge is not able to forecast its 2017 and 2018 Capital Budget requirements on a line by line basis, in the same way as has been done for 2014 to 2016. However, the Company understands that some parties do not agree with the proposal to update capital costs for 2017 and 2018 midway through the IR term.

108. In response, Enbridge has updated its Customized IR proposal to allow for Allowed Revenue amounts to be set for all five years at this time. To accomplish this, Enbridge has used the 2016 Capital Budget to represent its 2017 and 2018 capital spending requirements within the Allowed Revenue amounts for 2017 and 2018. The one change that Enbridge has made to the 2016 Capital Budget is that, for purposes of 2017 and 2018, the $8 million forecast spending on WAMS has been removed, since that project will have been completed by the end of 2016. Therefore, the Capital Budget used for 2017 and 2018 is the same as set out in the “Forecast 2016” column within Tables 1 and 2 above, except that the $8.1 million

associated with WAMS is removed, leaving a forecast Capital Budget of $441.9 million for each of 2017 and 2018.

109. The Company believes the 2016 Capital Budget sets out a reasonable forecast of its capital spending requirements for 2017 and 2018. The 2016 Capital Budget sets out Enbridge's capital spending requirements within the context of continuing customer growth, and new system reliability and integrity requirements. While some of the line item requirements within the Capital Budget will change each year, Enbridge believes that the overall capital spending requirements for 2017 and 2018 will be in line with 2016.

110. Indeed, using the 2016 Capital Budget to represent Enbridge's capital spending requirements for 2017 and 2018 likely understates the Company's actual requirements for those years.

111. One way this can be seen in within the Asset Plan. In that document, Enbridge has forecast that its distribution plant capital spending requirements for 2017 and 2018 will be $23 million and $50 million higher as compared to 2016 (see Exhibit B2, Tab 10, Schedule 1, at page 91). The Asset Plan also indicates that Enbridge expects its customer growth for 2017 and 2018 to continue at the same rate as forecast for 2016 (around 40,000 new customers per year).

112. Another way that the 2017 and 2018 Capital Budgets can be seen to be understated is from the fact that there is no allowance for cost inflation in an approach which keeps the 2016 Capital Budget flat for the following two years.

113. As explained above, there are large amounts of uncertain, or "variable", capital costs that may arise within the 2014 to 2016 period associated with the System Integrity and Reliability studies and programs (as well as variable costs associated with other capital spending projects). Exposure to these variable amounts, which

are not included within the 2014 to 2016 Capital Budgets, will continue in 2017 and 2018.

114. While Enbridge is prepared to take most of the risk associated with these "variable" capital costs for 2017 and 2018, there are two areas (relocations, and replacement mains requirements identified through pipeline inspection activities (including the ILI and MOP programs)) where a different approach is proposed. For each of these areas, Enbridge proposes variance accounts for 2017 and 2018, through which the allowed revenue implications of spending that is significantly higher or lower than included within the budget would be recoverable from ratepayers. Details of the proposed variance accounts can be found at Exhibit D1, Tab 8, Schedule 6. It should be noted that the variance accounts are only operative if the actual Allowed Revenue consequences of required additional spending in either area are more than $1.5 million above or below the forecast amount for that area (which is the same threshold as applies for Z Factors).

115. It is very difficult to forecast costs associated with relocations with any accuracy. This is described above, and within Exhibit B2, Tab 4, Schedule 1. That difficulty is exacerbated in years further into the future. Relocations requirements arise because of third party activities over which Enbridge has no control. Given the amount of development activity being undertaken within the Company's franchise areas, Enbridge observes that the amount and cost of relocation requirements is increasing even since the original filing in this proceeding. Therefore, the actual capital costs associated with relocations activity for 2017 and 2018 may be significantly higher than that forecast for 2016. It is for this reason that Enbridge proposes variance account treatment for 2017 and 2018 related to this category of activity.

116. One key “variable” cost that is not included within Enbridge’s capital cost forecasts for 2014 to 2016 is capital amounts related to pipeline replacement that is identified through the pipeline inspection programs. The Capital Budgets include the project costs for inspection and assessment of pipelines, but do not include the cost for replacements that result from the programs. The Miscellaneous Mains Replacement category of cost does not include any costs for pipeline replacement requirements identidifed through pipeline inspection programs. While Enbridge has indicated that it is prepared to take on the risk of the variable costs associated with these activities (capital amounts related to pipeline replacement) for 2014 to 2016, the Company believes that it is reasonable and appropriate to include variance account treatment for the revenue requirement implications of such costs for 2017 and 2018.

H. Conclusion

117. The balance of the B2 series of exhibits sets out the details of Enbridge’s 2014 to 2016 Capital Budget, organized by categories of capital spending (business areas). For each of the categories, the Company will provide Overview evidence, an explanation of the category’s capital budget, explanation of year-over-year budget variances, and individual project description documents for initiatives that have a capital budget over $2 Million during the three year term.

118. The following Table 13 sets out the direct costs for each of the major business areas detailed within the B2 series of Exhibits.

Table 13
Summary of Capital Expenditures by Business Area
($Millions)

		Col 1	Col 2	Col 3	Col 4
		Board Approved Budget	Forecast	Forecast	Forecast
Exhibit Reference	Business Area	2013	2014	2015	2016
B2-2-1	Customer Growth	95.9	91.2	97.5	102.3
B2-3-1	Reinforcements	11.4	11.4	16.9	8.8
B2-3-2	Major Reinforcements	63.4	202.2	359.7	-
B2-4-1	Relocations	15.2	15.2	13.4	12.6
B2-5-1	Sytem Integrity and Reliability	84.7	132.3	135.1	141.1
B2-6-1	Storage	19.0	19.2	13.8	8.9
B2-7-1	Business Development	0.3	3.5	3.6	3.7
B2-8-1	Information Technology	28.0	29.3	27.2	27.5
B2-8-2	Work and Asset Management System (WAMS)	0.5	35.7	23.7	7.7
B2-9-1	Facilities and General Plant (includes Fleet)	15.5	23.6	22.0	17.3
	Sub total Capital by Business Area	333.9	563.6	712.9	329.9
B2-1-1	Departmental Labour Costs	76.6	74.8	73.4	75.6
B2-1-1	Capitalized Administrative and General	33.6	35.5	36.4	37.1
B2-1-1	Interest During Construction	5.4	8.4	9.3	7.4
B2-1-1	Total Capital Expenditures	449.5	682.3	832.0	450.0

119. This Capital Budget Overview and Budget Process exhibit has explained the Company's approach, reasoning and decisions that led to the 2014 to 2016 Capital Budget. The budgeting process has ensured that Enbridge's Capital Budget reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. The inclusion of productivity savings within the Capital Budget reflects Enbridge's commitment to demonstrate cost effective operation during an extraordinary period of expenditure.

120. As explained at Exhibit A2, Tab 3, Schedule 1, the Capital Budgets for 2014 to 2016 are used as an input into the Allowed Revenue amounts for each year of the Customized IR term, with the adjusted 2016 Capital Budget (exclusive of WAMs spending) used as the relevant input for 2017 and 2018. This updated approach enables Allowed Revenue to be set for each of the five years of the Customized IR term.

Witnesses: J. Sanders
P. Squires

SYSTEM INTEGRITY AND RELIABILITY – OTHER PROGRAMS AND PROJECTS 2014 - 2016

Overview

1. Over the forecast period there are two programs and one project included in this grouping of evidence. These are the Meter and Regulator Replacement Program, the Distribution Records Management Program and the Envision Extension project. These programs and project are included in this grouping given that they generally support multiple operating assets (mains, service or stations) or cover a unique aspect of the operating system (residential and small commercial meters and regulators).

2. Further information is provided for the Meter and Regulator Replacement Program in this evidence under Exhibit B2, Tab 5, Schedule 5, Attachment 1, for the Distribution Records Management Program under Exhibit B2, Tab 5, Schedule 5, Attachment 2 and for the Envision Extension project under Exhibit B2, Tab 8, Schedule 2, /c
Attachment 3.

3. Table 1 provides the forecasted capital requirements for both programs and the Envision Extension project.

Witnesses: A. Creery
C. McCowan

Table 1: System Integrity and Reliability – Other Programs and Projects ($000)

Description	2013	2014	2015	2016
Meter and Regulator Replacement Program	23,520	24,169	25,911	28,115
Distribution Records Management Program	9,386	9,639	8,740	7,695
Envision Extension Project	–	8,000	8,000	–
Total	32,000	41,808	42,651	35,810

Witnesses: A. Creery
C. McCowan

REVENUE FORECAST

1. The purpose of this evidence is to summarize the revenue forecast for 2014 to 2018 provided in this application.

2. A summary of the revenue forecast for 2014 to 2018 is provided in Table 1 below.

Table 1

Revenue Forecast
($ millions)

	Col. 1 2013 Board Approved	Col. 2 2014 Budget	Col. 3 2015 Forecast	Col. 4 2016 Forecast	Col. 5 2017 Forecast	Col. 6 2018 Forecast
1.0 Gas Sales	2,043.8	2,253.5	2,404.3	2,464.5	2,480.3	2,496.2
2.0 Transportation of Gas	318.6	242.8	229.6	217.1	211.1	205.0
3.0 Transmission, Compression and Storage	1.7	1.8	1.8	1.8	1.8	1.8
4.0 Other Operating Revenue	45.0	40.6	41.0	41.3	41.3	41.3
5.0 Total Operating Revenue	2,409.1	2,538.7	2,676.7	2,724.7	2,734.5	2,744.3

3. The 2014 Revenue Budget is $2,538.7 million as shown at Exhibit C3, Tab 1, Schedule 1. This represents a $129.6 million increase over the 2013 Board Approved of $2,409.1 million. A comparison of the 2014 Budget of Utility Operating Revenues to the 2013 Board Approved Budget is provided at Exhibit C3, Tab 1, Schedule 2.

4. The 2015 Revenue Forecast is $2,676.7 million as shown at Exhibit C4, Tab 1, Schedule 1. This represents a $138.0 million increase over the 2014 Budget of $2,538.7 million. A comparison of the 2015 Forecast of Utility Operating Revenues to the 2014 Budget is provided at Exhibit C4, Tab 1, Schedule 2.

Witnesses: R. Lei
S. Qian

5. The 2016 Revenue Forecast is $2,724.7 million as shown at Exhibit C5, Tab 1, Schedule 1. This represents a $48.0 million increase over the 2015 Revenue Forecast. A comparison of the 2016 Forecast of Utility Operating Revenues to the 2015 Forecast is provided at Exhibit C5, Tab 1, Schedule 2.

6. The 2017 Revenue Forecast is $2,734.5 million as shown at Exhibit C6, Tab 1, Schedule 1. This represents a $9.8 million increase over the 2016 Revenue Forecast. A comparison of the 2016 Forecast of Utility Operating Revenues to the 2016 Forecast is provided at Exhibit C6, Tab 1, Schedule 2.

7. The 2018 Revenue Forecast is $2,744.3 million as shown at Exhibit C7, Tab 1, Schedule 1. This represents a $9.8 million increase over the 2017 Revenue Forecast. A comparison of the 2016 Forecast of Utility Operating Revenues to the 2017 Forecast is provided at Exhibit C7, Tab 1, Schedule 2.

8. The year over year variances are further explained by the revenue categories in the following paragraphs.

<u>Gas Sales and Transportation of Gas Revenues</u>

9. Gas sales and transportation of gas revenues for the 2014 Budget are updated on the basis of Q4 2013 rates that can be found in the Board Decision and Order for EB-2013-0295. Gas sales and transportation of gas revenues for 2015 Forecast, 2016 Forecast, 2017 Forecast and 2018 Forecast are developed based on the Q2 2013 rates that can be found in the Board Decision and Order for EB-2013-0045.

10. A breakdown of the 2014 Budget, 2015 Forecast, 2016 Forecast, 2017 Forecast and 2018 Forecast gas sales and transportation of gas revenues by rate class is

provided at Exhibit C3, Tab 2, Schedule 1, Exhibit C4, Tab 2, Schedule 1, Exhibit C5, Tab 2, Schedule 1, Exhibit C6, Tab 2, Schedule 1 and Exhibit C7, Tab 2, Schedule 1, respectively.

11. The increase in gas sales and transportation of gas revenues of $133.9 million from the 2013 Board Approved Budget to the 2014 Budget is primarily due to higher QRAM commodity rates, general service customer growth, partially offset by continuing decline in average use for general service customers and lower gas demand forecast resulting from a forecast of lower degree days. Please refer to Exhibit C3, Tab 2, Schedule 1 for the details of the 2014 volume forecast. Also please refer to Exhibit C3, Tab 2, Schedule 3 for a comparison of the 2014 Budget volume forecast to the 2013 Board Approved. The forecast for weather is described in the degree day forecast found at Exhibit C2, Tab 1, Schedule 2.

12. The increase in gas sales and transportation of gas revenues of $137.6 million from the 2015 Forecast to the 2014 Budget is primarily due to general service customer growth, higher QRAM commodity rates, partially offset by the continued decline in average use for residential customers. Please refer to Exhibit C4, Tab 2, Schedule 3 for a comparison of the 2015 Forecast volume forecast to the 2014 Budget.

13. The increase in gas sales and transportation of gas revenues of $ 47.7 million from the 2016 Forecast to the 2015 Forecast is primarily attributable to general service customer growth, partially offset by the continued decline in average use for residential customers. Please refer to Exhibit C5, Tab 2, Schedule 3 for a comparison of the 2016 Forecast volume to the 2015 Forecast.

Witnesses: R. Lei
S. Qian

14. The increase in gas sales and transportation of gas revenues of $15.9 million from the 2017 Forecast to the 2016 Forecast is primarily attributable to general service customer growth. Please refer to Exhibit C6, Tab 2, Schedule 3 for a comparison of the 2017 Forecast volume to the 2016 Forecast.

15. The increase in gas sales and transportation of gas revenues of $15.8 million from the 2018 Forecast to the 2017 Forecast is primarily attributable to general service customer growth. Please refer to Exhibit C7, Tab 2, Schedule 3 for a comparison of the 2018 Forecast volume to the 2017 Forecast.

Transmission, Compression and Storage

16. Transmission, Compression and Storage revenues for the 2014 Budget are also developed on the basis of Final Rate Order in EB-2011-0354. There are no significant variances from the 2014 Budget of $1.8 million compared to the 2013 Board Approved of $1.7 million.

Other Operating Revenues

17. Other Operating Revenues for the 2014 Budget of the revenue items identified at Exhibit C3, Tab 3, Schedule 1, are developed based on the Company's final rate set out in EB-2011-0354.

18. The decrease in Other Operating Revenues of $4.4 million from the 2013 Board Approved Budget to the 2014 Budget is primarily due to lower late payment penalties (LPP) in 2014, which are held at the 2012 level. In comparison, 2013 Board Approved was higher because it underestimated the LPP reduction resulting from the implementation of customer service rules; and 2013 Board Approved also assumed higher billed receivables driven by colder weather. A comparison of the

2014 Budget of Other Operating Revenues to the 2013 Budget is provided at Exhibit C3, Tab 3, Schedule 1.

19. The increase in Other Operating Revenues of $0.4 million from the 2015 Forecast to the 2014 Budget is primarily due to slightly higher NGV revenues driven by expected growth in NGV customers. A comparison of the 2015 Forecast of Other Operating Revenues to the 2014 Budget is provided at Exhibit C4, Tab 3, Schedule 1.

20. The increase in other Operating Revenues of $0.3 million from the 2016 Forecast to the 2015 Forecast is primarily due to slightly higher NGV revenues driven by continued growth in the number of NGV customers. A comparison of the 2016 Forecast Other Operating Revenues to the 2015 Forecast is provided at Exhibit C5, Tab 3, Schedule 1.

21. Evidence on the NGV program is presented at Exhibit C3, Tab 5, Schedule 1. Evidence on Transactional Services is presented at Exhibit C1, Tab 3, Schedule 1. Evidence on Other Service Charges, Administrative and Late Payment Penalty Revenue is presented at Exhibit C1, Tab 4, Schedule 1.

22. There is no change in other Operating Revenues from the 2017 Forecast to the 2016 Forecast as the 2017 Forecast other Operating Revenues remain at the 2016 Forecast Operating Revenues.

23. There is no change in other Operating Revenues from the 2018 Forecast to the 2017 Forecast as the 2018 Forecast other Operating Revenues remain at the 2017 Forecast Operating Revenues.

Witnesses: R. Lei
S. Qian

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2014 forecast of volumes and the preliminary volume forecast for 2015 to 2018, which will be subject to annual adjustments to reflect updated forecast assumptions. Due to the annual adjustments, 2017 and 2018 volumes are assumed at the same level as 2016. The evidence describes the forecasting methodology and the key assumptions used to develop the volumes forecast for the General Service and Large Volume Budgets. The volume forecasts for 2014 to 2018 have been prepared based on the methodology applied in prior rate case filings.

2. A summary of the volumes forecast for the years from 2013 to 2018 is provided below. Further rate class detail and explanation for all gas volumes and related items are provided at Exhibit C3, Tab 2, Schedule 3; Exhibit C4, Tab 2, Schedule 1; Exhibit C5, Tab 2, Schedule 1; Exhibit C6, Tab 2, Schedule 1 and Exhibit C7, Tab 2, Schedule 1.

Table 1
Summary of Gas Sales and Transportation Volumes
(Volumes in 10^6m^3)

	2013 Board Approved Budget	2014 Budget	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
General Service Volumes	9 558.9	9 190.0	9 272.2	9 369.1	9 369.1	9 369.1
Contract Market Volumes	1 945.5	1 966.0	1 977.3	1 979.3	1 979.3	1 979.3
Total Volumes, Gas Sales and Transportation	11 504.4	11 156.0	11 249.5	11 348.4	11 348.4	11 348.4

3. Total customers are reported on an annual average of monthly customer numbers. This annual average customer methodology has been used to develop Board Approved annual average customer numbers for more than ten years.

Witnesses: R. Cheung
S. Qian

Table 2 illustrates the annual average number of general service and contract market customers for the forecast years. The methodology used to develop the customer budget can be found at Appendix B of this evidence.

Table 2
Summary of Total Average Number of Customers

	2013 Board Approved Budget	2014 Budget	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
General Service Customers	2 025 038	2 059 216	2 094 900	2 131 485	2 168 070	2 204 654
Contract Market Customers	424	403	402	402	402	402
Total Number of Customers (Average)	2 025 462	2 059 619	2 095 302	2 131 887	2 168 472	2 205 056

General Service Demand Forecast Methodology

4. The general service volume forecast is derived using the general service customer budget and the normalized average use per customer forecast generated from the average use forecasting models. The 2014 volume budget incorporates calendar 2012 actual billing data.

5. The average use forecasting models are the Company developed regression models, which are described in detail in the evidence at Exhibit C2, Tab 1, Schedule 3. The forecast incorporates economic assumptions from the Economic Outlook, Spring 2013. Key economic assumptions can be found at Exhibit C2, Tab 1, Schedule 1. The average use regression models forecast also includes 2012 actual billing consumption information.

Witnesses: R. Cheung
S. Qian

6. The major variables in Rate 1 and Rate 6 models are heating degree days, vintage (Rate 1 only), employment, Ontario real gross domestic product, vacancy rates (Rate 6 only), real energy prices, and time trend. Annual econometric models are employed to model and quantify the impact of different variables on average use per customer. The vintage variable is constructed to reflect the impact that new homes, associated with more energy efficient gas equipment and enhanced building codes, have on average use. The time trend, including the dynamic variable in the regression model, captures the historical actual average trend of the sectoral average use, conservation initiatives originated by customers themselves or promoted by government programs, stock turnover and other historical impact not reflected in the mentioned driver variables.

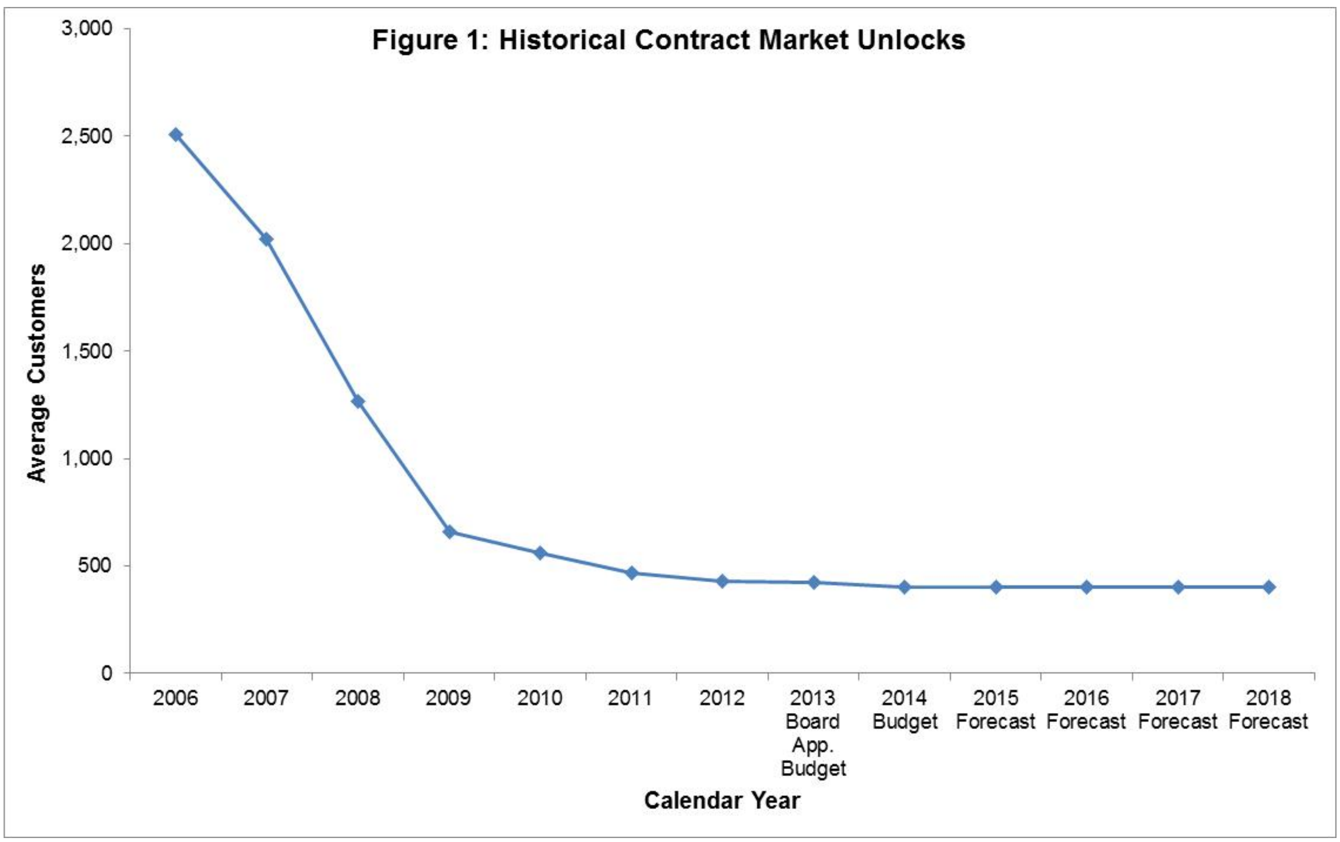
7. The forecast of average use per customer is prepared based upon the analysis of weather-normalized volumes data. Normalization is the process that allows the Company to compare average use per customer by removing the influence of the weather. The Company's weather normalization methodology has been approved by the Board and utilized for more than ten years.

8. Consistent with previous rate cases, the Company continues to report the results that the models would generate using the actual data and driver variable information to allow parties to compare the results to the prior year's forecast. The Rate 1 average in-sample forecast error of regression models is 0.8% and the Rate 6 average in-sample forecast error is about 1.0% on average during 2003 to 2012. Overall, the regression model continues to be an excellent predictor of general service average use.

Contract Market Volume Forecast Methodology

9. The contract market volume budget was generated using the established grass roots approach. Volumes are forecasted on an individual customer basis by account executives in consultation with customers during the budget process. Specifically, the account executive review the contract attributes for each contract in order to ensure that the customer can meet the contracted rate class minimum volume and load factor requirements. Current economic and industry conditions and budgeted degree days, are factored into the budget determination.

10. Figure 1 below shows the trend of historical actual contract market unlocks between 2006 and 2012 and the projection for the years from 2013 to 2018.



Witnesses: R. Cheung
S. Qian

11. As the above graph illustrates, approximately 2,000 contract market customers migrated to general service over the period 2006 through 2010. As shown in Figure 3, this customer migration drove up the average use per customer in Rate 6 during that period. In the past few years, contract market customers have remained at the same level.

12. As a consequence of the implementation of the Natural Gas Electricity Interface Review ("NGEIR") in 2007, the Company experienced customer migration from bundled rate classes that bill distribution volumes volumetrically, reported in Table 1, to unbundled rate classes (e.g., Rate 125, Rate 300 Firm) that do not bill distribution volumes volumetrically. Unbundled customers incur monthly contract demand volumes and generate fixed contract demand revenues. Table 3 below presents a summary of these contract demand volumes.

Table 3
Summary of Unbundled Customers Contract Demand Volumes
(Volumes in 10^6m^3)

	2013 Board Approved Budget	2014 Budget	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Total Contract Demand Volumes	119.5	119.4	119.4	119.4	119.4	119.4

2014 Volume Budget

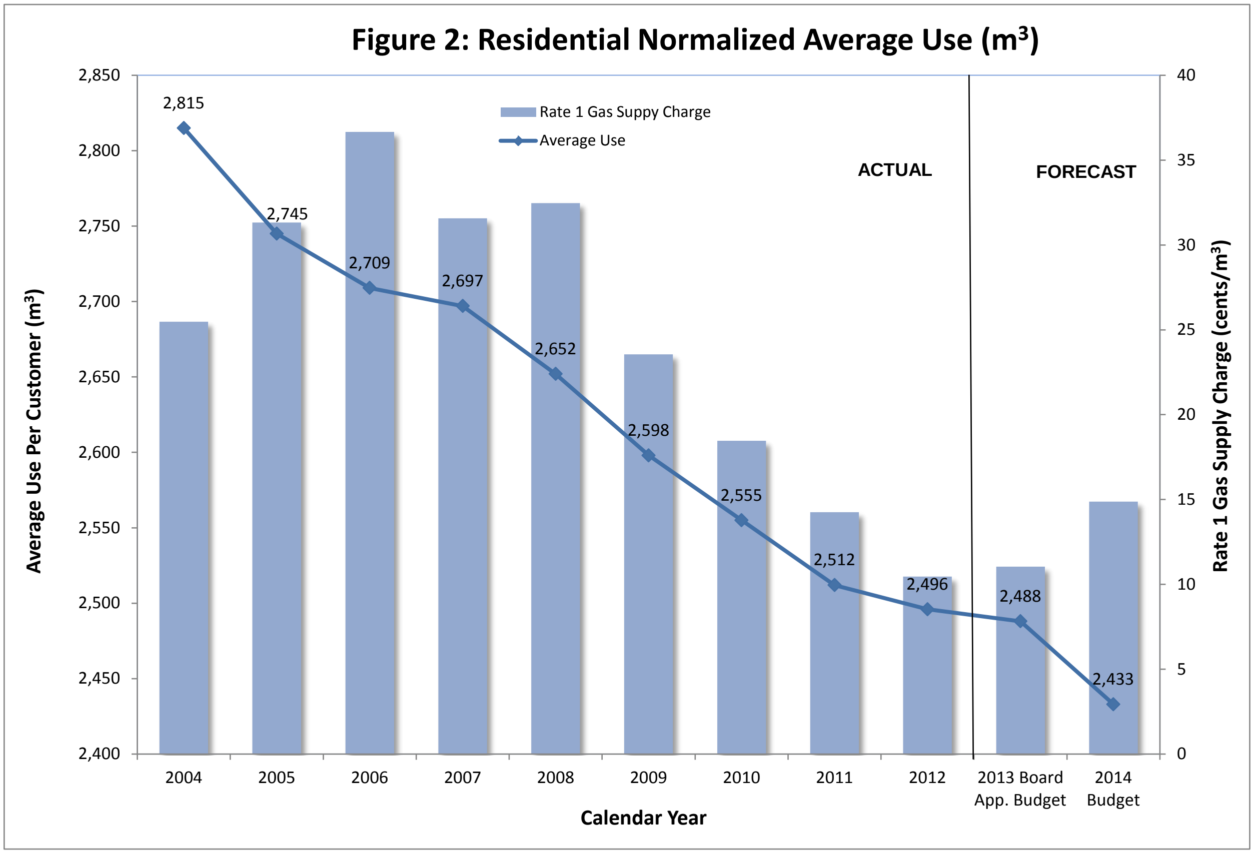
13. The 2014 Budget volumes reflect the meter reading heating degree days forecast for the Central Region of 3,517. The 2014 Budget is comprised of General Service volumes of 9,190.0 10^6m^3 and Contract Market volumes of 1,966.0 10^6m^3. Detailed breakdown of gas volumes by rate class is provided at Exhibit C3, Tab 2,

Witnesses: R. Cheung
S. Qian

Schedule 1. Monthly meter reading heating degree days are determined by combining the Gas Supply heating degree day forecasts with the billing schedules. Evidence related to the forecast of degree days is presented at Exhibit C2, Tab 1, Schedule 2.

14. Appendix A of this evidence presents the historical normalized actual and Board approved general service average uses. In addition, in order to eliminate the weather impact for year over year comparison, normalized average uses are also normalized to the 2014 test year forecast degree days at Appendix A.

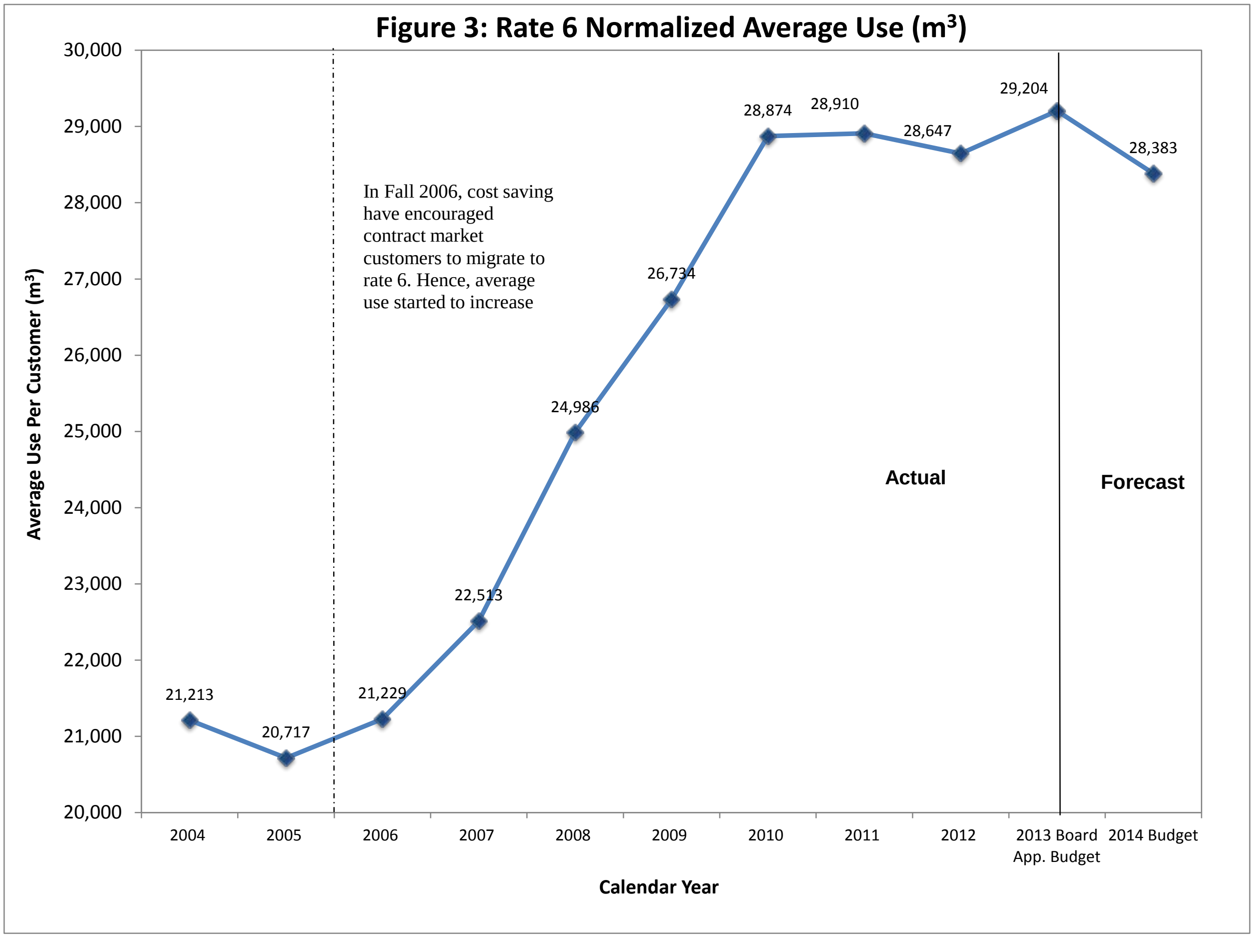
15. Residential average use per customer has declined steadily over the period of 2004 through 2012, average at a rate of 1.5% per year. Figure 2 depicts this trend.



16. Residential average use is forecast to decline in 2014 primarily due to the following reasons:
    - Replacement of older, less efficient appliances with newer high efficient units by customers;
    - Home improvements by customer, e.g., upgrades to insulation, windows and doors;
    - Conservation initiatives originated by customers and also government policies and programs aimed at improving efficiencies;
    - The 2006 Building Code includes enhance requirements for houses came into force in December 31, 2006. New requirements for near-full-height basement

insulated came into force December 31, 2008. In 2012, new houses were required to meet standards in accordance with the national guideline, EnerGuide 80.

17. From 2006 to 2010, the small apartment, commercial and industrial (Rate 6) average use per customer has increased by an average of 6.7% per year during this period. The increase in actual usage was largely attributable to the rate switching from contract market customers to general service, which began in the fall of 2006. However, the rate migration has stabilized since 2010 and the Rate 6 average use decreased in 2012 compared to 2011, which is primarily driven by the customer volatility in the industrial sector, as well as efficiency improvements in apartment sectors. The following Figure 3 shows the normalized actual average use per customer for Rate 6 from 2004 to 2012, and the projection for 2013 to 2014, as filed at Table 2 and Table 3 of Appendix A of this evidence.



18. From the figure above, there is a clear upward trend in usage per customer from 2006 to 2010. It is largely attributable to the customer migration from contract market to general service as described in Figure 1. Rate design changes to include contract demand charges for Rate 100 and Rate 145, which became effective April, 2007, prompted much of this rate migration. Approximately 2,000 contract market customers have migrated to general service over the period from 2006 through 2010. Over the past few years, the rate migration has stabilized and the Rate 6 average use per customer has reflected a relatively flat or downward trend. Based on the driver variables in the updated regression models which incorporate 2012

actual billing data and latest economic assumptions, it is expected that the Rate 6 average use per customer will decrease in 2014 compared to 2013 Board Approved Budget. Compared to 2012 actual, the Rate 6 average use in 2014 is relatively flat.

Comparison of 2014 Budget and 2013 Board Approved Budget

19. The 2014 Budget volumes reflect the heating degree days forecast for the Central Region of 3,517, a decrease of 151 degree days compared to the 2013 Budget level of 3,668.

20. The 2014 Budget volumes of 11 156.0 10^6m^3 forecast to be 348.4 10^6m^3, or 3.0%, below the 2013 Board Approved Budget of 11 504.4 10^6m^3. The decrease is primarily attributable to the lower degree days forecast and other factors discussed below. On a weather-normalized basis, the 2014 Budget volumes are forecast to be 87.0 10^6m^3 lower than the 2013 Budget. The volume decrease on a normalized basis is made up of a decrease in General Service of 111.9 10^6m^3, partially offset by an increase in contract market volumes of 24.9 10^6m^3. Further rate class detail and explanations are provided at Exhibit C3, Tab 2, Schedule 3.

21. The decrease in the general service volumes of 111.9 10^6m^3 on a weather-normalized basis is primarily due to lower average use per customer in Rate 1 totaling 105.5 10^6m^3 and lower average use per customer in Rate 6 totaling 106.6 10^6m^3, partially offset by net customer growth of 105.7 10^6m^3. Continuous home improvements and conservation initiatives are assumed to be the primary drivers of the decline in residential average use per customer.

22. The 2014 large volume budget is expected to see an increase of 24.9 10^6m^3 compared to the 2013 Budget on a weather-normalized basis. The variance is

mainly due to the increase in the industrial sector of 22.9 10^6m^3, Rate 200 of 1.8 10^6m^3 and the apartment sector of 0.4 10^6m^3, partially offset by the decrease of commercial sector of 0.2 10^6m^3. Table 4 below illustrates the major drivers contributing to the increase in contract market volumes between the 2014 Budget and the 2013 Budget.

Table 4 - Comparison of Contract Market Volumes
2014 Budget and 2013 Board Approved Budget
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2014 Budget	2013 Borad Approved Budget	2014 Budget Over (Under) 2013 Budget (1-2)
Contract Market - Total Gas Sales and Transportation Volumes	1,966.0	1,945.5	20.5
Major Variance Factors:			
Weather Normalization, Exhibit C3, Tab 2, Schedule 3, Page 2, Col. 4, Item No. 4			(4.4)
Transfer gains - net migration of customers from general service rate 6 to contract rates			71.5
Transfer losses - net migration of customers from contract rates to general service rate 6			(67.4)
Wholesale customer			1.8
Non-Metallic Mineral Products			8.2
Transportation Equipment			6.4
Primary Metal & Machinery			4.7
Impact of price spread between Hydro and Gas on Distributed Energy customers			4.5
Chemical and Chemical Products			(5.0)
Other			0.2
Total Major Variance Factors:			**20.5**

2015 and 2016 Gas Volume Forecast

23. As explained in Exhibit A2, Tab 1, Schedule 1, the Gas Volume Budget for 2015 and 2016 will be updated within annual rate adjustment proceedings. The forecasts presented here are provided in order to provide estimated rate impacts for 2015 and 2016. As explained at Exhibit A2, Tab 3, Schedule 1, the 2016 Gas Volume Budget

is used to set preliminary Allowed Revenue amounts for 2017 and 2018. The forecasts will be updated within 2017 and 2018 Rate Adjustment proceedings.

24. Similar to 2014 Budget, both 2015 and 2016 Forecast volumes also reflect the heating degree days forecast for the Central Region of 3,517. The methodology used to forecast the volumes and the number of customers for 2015 and 2016 are consistent to the one used in preparation of 2014 Budget. Detailed breakdown of gas volumes by rate class are provided at Exhibit C4, Tab 2, Schedule 1 for 2015 forecast and Exhibit C5, Tab 2, Schedule 1 for 2016 forecast.

25. Total volumes forecast between the years 2015 and 2016 are expected to increase by an average of 0.8% each year. The Company expects to increase its distribution customer base by 1.7% during both forecast years. Customer growth is anticipated to offset the declining demand of residential customers as a result of continuing trend of declining residential average use per customer in both 2015 and 2016 Forecast.

26. Residential normalized average use per customer is forecast to decline by an average of 0.85% from the years 2015 to 2016. Efficiency improvements continue to be the key driver of the decline in residential average use per customer. On the other hand, the total Rate 6 normalized average use per customer is projected to be flat over the forecast years.

<u>Comparison of 2015 Forecast and 2014 Budget</u>

27. The 2015 Forecast volumes of the 11 249.5 10^6m^3 are 93.5 10^6m^3, above the 2014 Budget of 11 156 10^6m^3. This variance is made up of increase in the general service volumes of 82.2 10^6m^3 and the increase in the contract market of

11.3 10^6m^3. Further rate class detail and explanations are provided at Exhibit C4, Tab 2, Schedule 3.

28. The increase in the volumes demand of 93.5 10^6m^3 is primarily due to the following factors:
    - Additional 35,684 general service customers, as stated at Exhibit C4, Tab 2, Schedule 2, result an increase in volume demands of 110.1 10^6m^3;
    - Lower residential average use per customer results a forecast decrease in total volumes demand of 39.5 10^6m^3;
    - Slightly higher average use per customer in small apartment, commercial and industrial sector results a forecast increase in volume demand of 11.0 10^6m^3;
    - A modest increase from the contract market customers of 11.3 10^6m^3 is primarily due to the improved economic conditions in contract market.

Comparison of 2016 Forecast and 2015 Forecast

29. The 2016 Forecast volumes of the 11 348.4 10^6m^3 are forecast to be 98.9 10^6m^3, above the 2015 Budget of 11 249.5 10^6m^3. The variance is made up of increase in the general service volumes of 96.9 10^6m^3 and the increase in the contract market of 2.0 10^6m^3. Further rate class detail and explanations are provided at Exhibit C5, Tab 2, Schedule 3.

30. Key drivers and the offsetting factors that contribute to the increase in volumes demand of 98.9 10^6m^3 are as follows:

    - Additional 36,585 general service customers, as stated at Exhibit C5, Tab 2, Schedule 2, result an increase in volume demands of 117.0 10^6m^3;

Witnesses: R. Cheung
S. Qian

- Lower residential average use per customer by 20 m^3, which results a forecast decrease in total volumes demand of 39.5 $10^6 m^3$;

- Higher average use per customer in small apartment, commercial and industrial sector results a forecast increase in volume demand of 19.4 $10^6 m^3$;
- A modest increase from the contract market customers of 2.0 $10^6 m^3$.

<u>Evaluation of Forecast Accuracy – Historical Normalized Actual vs. Board Approved Budget</u>

31. Historical Board Approved volumes were developed and approved based upon fiscal year information. For the periods prior to 2006 September 30 is fiscal year end whereas for the years 2006 and beyond the fiscal year is the calendar year.

32. The key factor used to evaluate the accuracy of the general service volumetric demand is the variance of normalized residential average use per customer. The General Service Average Use Table 1 of the Appendix A at this evidence illustrates a 10-Year history of Normalized Actual vs. Board Approved volumes. The average normalized percentage variances between 2003 and 2012 was less than 0.8% for Rate 1 and about 1.2% for Rate 6. Hence, the general service average use forecasting methodology continues to be a reasonable predictor for general service average use.

33. For the contract market, customer migration has had a significant impact between 2006 and 2010. In addition, the contract market volumes are primarily driven by economic factors. The Table 4 at Appendix A of this evidence illustrates a 10-Year history of Normalized Actual vs. Board Approved volumes for contract market customers to evaluate accuracy of forecast volumes.

Weather Normalization Methodology

34. The Company's weather normalization methodology has been approved by the Board and utilized for more than ten years. Consistent with the previous rate case, this section explains the Board approved normalization methodology of normalizing actual consumption for general service rate classes.

35. General Service normalization is carried out taking customers at a group level. The Company's General Service customers are grouped together into homogenous classes of gas usage within the three delivery areas (and six operating regions) of the Company's franchise area. Only the heat sensitive portion of consumption is normalized for heat sensitive or balance point degree days.

36. Firstly, the total load per customer of a customer group is calculated by dividing the group's consumption by the total customers within this group. Then, base-load per customer is calculated by taking an average of the two non-weather sensitive summer months' total load. Base-load represents non-weather sensitive load, such as water heating and other non-heating uses. Thereafter, heat-load per customer is calculated by subtracting the base-load per customer from the total load per customer. This heat-load represents the heat sensitive portion of consumption. By dividing the heat-load per customer by Actual Heating Degree Days, an Actual Use per Degree Day is generated. The Actual Use per Degree Day is then adjusted to reflect normal weather by multiplying the Budget Heating Degree Days. Consequently, total normalized average use per customer is defined as an aggregate sum of base-load use per customer and normalized heat-load per customer.

Witnesses: R. Cheung
S. Qian

37. For contract market customers who consume more than 340,000 m^3 annually, a similar process is followed to determine the actual base-load for each contract. Actual heat-load is obtained by removing the base-load and the process load from the total consumption, which is then adjusted to reflect normal weather. The actual volumes are also adjusted, where necessary, to the budgeted level of curtailment.

Witnesses: R. Cheung
S. Qian

AVERAGE NUMBER OF CUSTOMERS

1. The purpose of this exhibit is to present the calculation of the 2014 annual average customers underpinning the 2014 volume budget as well as the preliminary customer forecast 2015 to 2018. The annual average customer methodology used by the Company has been applied to calculate Board Approved annual average customer for more than ten years.

2. The 2014 Customer Budget of 2,059,619 is forecast to be 34,157, or 1.7%, above the 2013 Board Approved Budget of 2,025,462. The increase in customers is primarily attributable to the customer additions in the 2014 Budget. The total customer additions forecast for 2014 are 36,647. The customer additions forecast underpins the new customer volumes of 105.7 10^6m^3 added between 2014 Budget and 2013 Budget as stated at Exhibit C3, Tab 2, Schedule 3.

3. The 2015 Customer Forecast of 2,095,302 is forecast to be 35,683, or 1.7%, above the 2014 Budget. The increase in customers is primarily attributable to the forecast of customer additions in 2015 of 38,489. The customer additions forecast contributes to the volumes demand increase of 110.1 10^6m^3 between 2015 Forecast and 2014 Budget as stated at Exhibit C4, Tab 2, Schedule 3.

4. The 2016 Customer Forecast of 2,131,887 is forecast to be 36,585, or 1.7%, above the 2015 Forecast. The increase in customers is primarily attributable to the forecast of customer additions in 2016 of 39,645. The customer additions forecast contributes to the volumes demand increase of 117.0 10^6m^3 between 2016 Forecast and 2015 Forecast as stated at Exhibit C5, Tab 2, Schedule 3.

Witnesses: R. Cheung
S. Qian

5. The 2017 Customer Forecast of 2,168,472 is forecast to be 36,585, or 1.7%, above the 2016 Forecast. The increase in customers is primarily attributable to the forecast of customer additions in 2017.

6. The 2018 Customer Forecast of 2,205,056 is forecast to be 36,584, or 1.7%, above the 2017 Forecast. The increase in customers is primarily attributable to the forecast of customer additions in 2018.

Underlying Forecast Methodology

7. Consistent with previous rate proceedings, each year's customer numbers are reported on an annual average of monthly customer numbers. Every month customer numbers are measured by number of active meters (or unlock meters)[1]. As a result, each month's customer number is an aggregate sum of the total active meters for that particular month. Specifically, each year's annual average is calculated as follows:

   annual average_customer = (1/12)(january_customer + february_customer + march_customer + april_customer + may_customer + june_customer + july_customer + august_customer + september_customer + october_customer + november_customer + december_customer)*

8. Consistent with the contract demand forecast methodology discussed in the Gas Volume Budget evidence, contract customer counts in the contract market are generated through the grass root approach between account executives and customers. The formula for forecasting the total number of contract market customers is as follows:

[1] Unlock meter is defined as customer whose gas meter is unlocked, allowing gas to flow through the meter to a premise.

forecast contract market customers = year end customers (2013 Estimate)

+ forecast new customer additions

+ forecast replacement customer additions

- forecast lost customers

+ forecast transfer gains (i.e. customer migration from general service Rate 6 to contract market rate class)

– forecast transfer losses (i.e. customer migration from contract market rate class to general service Rate 6)

9. The forecast of total number of general service customers is obtained by adding the forecast customer additions along with a time lag between customer additions and unlock meters to the number of customers recorded at the end of the prior year's forecast. Historical average monthly change in actual lock meters or customers are then added to these numbers. Transfer gains or losses between contract rate class and general service Rate 6 obtained from account executives are then layered onto general service Rate 6 customers. The formula for forecasting the total number of general service customers is as follows:

forecast general service customers = year end customers

*+ forecast new construction customer additions*new construction time lag*

*+ forecast replacement customer additions*replacement time lag*

+ historical average monthly change in actual lock customers

+ forecast transfer gains (i.e. customer migration from contract market rate class to general service Rate 6)

- forecast transfer losses (i.e. customer migration from general service Rate 6 to contract market rate class)

Witnesses: R. Cheung
S. Qian

10. Lock meters are defined as customers whose gas meters are locked and no gas is flowing through the meter to a premise. These can result from vacant premises (e.g., new construction, move-in/move out, bankruptcies, etc.), customer switching off gas to an alternate energy source, payment or credit reasons and seasonal usage. Company has experienced an increase in lock meters, which has resulted in reduced net customer growth. Unfavorable economic conditions, e.g., vacancy or bankruptcy, may lead to an increase in locked meters and this factor has been incorporated into the customer forecast. Table 1 below presents the historical annual actual lock customer data.

Table 1 - Historical Annual Average Locks Customers

Calendar Year	Lock Customers
2010	40,518
2011	41,170
2012	43,575

11. There is always a time lag between when the service line is installed (that underpins capital expenditures and customer additions) and the flow of gas which occurs when the customer moves into the premise and calls to have their meter unlocked by field staff, gas service and their account (that underpins billed revenues and volumes) is activated. This time lag is incorporated into the customer number calculation.

12. Similar to lock customers, this time lag is challenging to predict. Therefore, the latest available historical actual data is used in order to obtain an objective forecast of lock meters for the budget. Table 2 below, presents a summary of the 2014 budgeted time lag. It is expected the average time lag (i.e., number of months) for

replacement customer additions will be shorter than new construction or subdivision customer additions. Also, the average time lag for commercial buildings or offices is anticipated to be longer than residential homes.

Table 2 - 2014 Budget Time Lag (i.e. Number of Months)

Sector	New Construction	Replacement
Residential	6	3
Apartment	7	7
Commercial	12	11
Industrial	7	7

Evaluation of Forecast Accuracy – Historical Actual vs. Board Approved Budget

13. Historical Board Approved customer numbers are set out on Table 3. The information for periods prior to 2006 shown in this Exhibit is presented on a September 30 fiscal year end whereas the fiscal-year for 2006 and beyond is the calendar year.

14. Table 3 on the following page illustrates 18 years of Historical Actual vs. Board Approved customer numbers. The average percentage error variances over the past 18 years were 516 customers or around 0.1%. Overall, the existing methodology has continued to be a good predictor of actual customers.

TABLE 3 - GENERAL SERVICE AND CONTRACT MARKET CUSTOMERS

	Test Year	Col. 1 Actual Customers	Col. 2 Board Approved Customers	Col. 3 Variance Customers (1-2)	Col. 4 %Variance Customers (3/2)*100
FISCAL YEAR	1995	1,222,293	1,216,511	5,782	0.5%
	1996	1,263,290	1,262,815	475	0.0%
	1997	1,312,434	1,309,752	2,682	0.2%
	1998	1,364,350	1,353,178	11,172	0.8%
	1999	1,414,788	1,417,832	(3,044)	-0.2%
	2000	1,464,738	1,468,915	(4,177)	-0.3%
	2001	1,519,039	1,514,710	4,329	0.3%
	2002	1,566,710	1,565,017	1,693	0.1%
	2003	1,622,016	1,615,037	6,979	0.4%
	2004*	1,676,380	1,672,586	3,794	0.2%
	2005	1,724,716	1,718,766	5,950	0.3%
CALENDAR YEAR	2006	1,782,813	1,792,615	(9,802)	-0.5%
	2007	1,824,789	1,823,258	1,531	0.1%
	2008	1,865,020	1,864,047	973	0.1%
	2009	1,887,605	1,906,437	(18,832)	-1.0%
	2010	1,926,294	1,931,528	(5,234)	-0.3%
	2011	1,960,378	1,965,538	(5,160)	-0.3%
	2012	1,994,903	1,984,734	10,169	0.5%

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at column 2 because Board Approved numbers are not available since there was no 2004 Board Approved Volumes Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

Witnesses: R. Cheung
S. Qian

OPERATING COST SUMMARY

1. This evidence shows a summary of EGD's cost of service for each of the 2013 Board Approved, and the 2014 through 2018 Fiscal Year forecasts.

Table 1
Operating Cost Summary

Line No.	($millions)	2013 Board Approved (a)	2014 Fiscal Year (b)	2015 Fiscal Year (c)	2016 Fiscal Year (d)	2017 Fiscal Year (e)	2018 Fiscal Year (f)
1	Gas costs	1,342.8	1,455.9	1,606.8	1,632.5	1,632.5	1,632.5
2	Operation and maintenance	414.9	425.3	428.5	439.5	450.5	461.8
3	Depreciation and amortization expense	279.3	262.8	276.6	303.9	313.4	322.1
4	Fixed financing cost	2.3	1.9	1.9	1.9	1.9	1.9
5	Municipal and other taxes	39.3	41.2	43.1	45.5	47.9	50.4
6	Operating costs	2,078.6	2,187.1	2,356.9	2,423.3	2,446.2	2,468.7
7	Income tax expense	51.9	33.5	13.8	4.5	8.6	15.8
8	Cost of service (excl, interest & return)	2,130.5	2,220.6	2,370.7	2,427.8	2,454.8	2,484.5

2. Explanations of the year over year changes in the operating cost items shown above is found in evidence at Exhibits D3/D4/D5/D6/D7, Tab 2, Schedule 1 and Updated Exhibit A2, Tab 3, Schedule 1.

3. Written evidence with respect to the details within each of the above forecast elements, for the 2014 through 2016 fiscal years, is found in evidence at Exhibit D1, Tabs 2 through 20.

4. The starting point for EGD's forecast total costs and expenses, standard and accepted regulatory and non-utility adjustments, and utility income tax calculations can be found at Exhibits D3, D4, D5, D6, & D7, Tab 1.

Witness: K. Culbert

DEFERRAL AND VARIANCE ACCOUNTS

2013 Test Year Approved Deferral and Variance Accounts

1. The following is EGD's list of 2013 Board Approved deferral and variance accounts ("DA" and "VA"). For the 2013 deferral and variance accounts approved and listed below, EGD will file a separate application requesting a process for the review and proposed clearance of the accounts as soon as feasibly possible following the public release of its fiscal 2013 year-end financial results (in March or April 2014).

2013 Purchased Gas Variance Account ("PGVA"),
2013 Design Day Criteria Transportation Deferral Account ("DDCTDA"),
2013 Transactional Services Deferral Account ("TSDA"),
2013 Unaccounted for Gas Variance Account ("UAFVA"),
2013 Storage and Transportation Deferral Account ("S&TDA")
2013 Deferred Rebate Account ("DRA"),
2013 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2013 Average Use True Up Variance Account ("AUTUVA"),
2013 Carbon Dioxide Offset Credits Deferral Account ("CDOCDA"),
2013 Manufactured Gas Plant Deferral Account ("MGPDA"),
2013 Gas Distribution Access Rule Costs Deferral Account ("GDARCDA"),
2013 Ontario Hearing Costs Variance Account ("OHCVA"),
2013 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2013 Open Bill Revenue Variance Account ("OBRVA"),
2013 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2013 Post-Retirement True-Up Variance Account (PTUVA"),
2013 Transition Impact of Accounting Changes Deferral Account ("TIACDA"),
2013 Demand-Side Management Variance Account ("DSMVA"),

Witnesses: K. Culbert
D. Small

2013 Lost Revenue Adjustment Mechanism Variance Account (“LRAM”),
2013 Demand Side Management Incentive Deferral Account (“DSMIDA”)

<u>2014 through 2018 Fiscal Year Proposed Deferral and Variance Accounts</u> /u

2. The Company has reviewed the existing required and potential requirement for deferral and variance accounts during the 2014-2018 rate making period and /u proposes the following accounts be established for use during the period. Within the list of accounts, the following are newly proposed accounts, CCSPDA, GGEIDA, CDNSADA, UDCDA, GTAPVA, RLMVA and RPMVA with separate written evidence /u provided within the D1 series of exhibits. The remainder of the accounts have been previously approved, though there are proposed revisions to the ongoing scope of several of these accounts: GDARIDA, OBRVA, TIACDA, TSDA and DSMVA.

2014-2018 Purchased Gas Variance Account (“PGVA”),
2014 Unabsorbed Demand Cost Deferral Account (“UDCDA”)
2014 Design Day Criteria Transportation Deferral Account (“DDCTDA”),
2014-2018 Transactional Services Deferral Account (“TSDA”),
2014-2018 Unaccounted for Gas Variance Account (“UAFVA”),
2014-2018 Storage and Transportation Deferral Account (“S&TDA”)
2014-2018 Deferred Rebate Account (“DRA”),
2014-2018 Customer Care Services Procurement Deferral Account (“CCSPDA”),
2014-2018 Customer Care CIS Rate Smoothing Deferral Account (“CCCISRSDA”),
2014-2018 Average Use True Up Variance Account (“AUTUVA”),
2014-2018 Greenhouse Gas Emissions Impact Deferral Account (“GGEIDA”),
2014-2018 Earnings Sharing Mechanism Deferral Account (“ESMDA”)
2014-2018 Manufactured Gas Plant Deferral Account (“MGPDA”),
2014-2018 Gas Distribution Access Rule Impact Deferral Account (“GDARIDA”),
2014-2018 Ontario Hearing Costs Variance Account (“OHCVA”),

2014-2018 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2014-2018 Open Bill Revenue Variance Account ("OBRVA"),
2014-2018 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2014-2018 Post-Retirement True-Up Variance Account ("PTUVA"),
2014-2018 Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA"),
2014-2018 Transition Impact of Accounting Changes Deferral Account ("TIACDA"),
2014-2018 Demand-Side Management Variance Account ("DSMVA"),
2014-2018 Lost Revenue Adjustment Mechanism Variance Account ("LRAM"),
2014-2018 Demand Side Management Incentive Deferral Account ("DSMIDA"),
2015-2018 Greater Toronto Area Project Variance Account ("GTAPVA"), /u
2017 -2018 Relocation Mains Variance Account ("RLMVA") and /u
2017-2018 Replacement Mains Variance Account ("RPMVA"). /u

Following the end of each year (2014 to 2018), EGD will file a separate application requesting a process for the review and proposed clearance of these deferral and variance accounts as soon as feasibly possible following the public release of its fiscal year-end financial results for that year (in March or April of the following fiscal year).

<u>Descriptions of Accounts</u>

<u>Purchased Gas Variance Account ("2014 to 2018 PGVA")</u>

3. The purpose of the PGVA is to record the effect of price variances between actual gas purchase prices and forecast prices which underpin the revenue rates to be charged in each fiscal year. Without this variance account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower

than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This variance account ensures that such effects are eliminated.

4. The Company has outlined the following methodology and scope to be in effect for the determination of amounts to be captured and cleared with respect to the 2014 PGVA. At this time, the basic premise and methodology to be used in determining what is to be included within the 2015 through 2018 PGVA accounts will not likely be materially different than that currently approved. However, the Company is not able to fully define what scope changes will potentially be required as a result of the planned GTA project and its gas supply plan implications. The Company proposes that it will bring forward a methodology scope for each of the 2015 through 2018 PGVAs within the rate adjustment applications for each of 2015 through 2018 (as outlined in evidence at Exhibit A3, Tab 3, Schedule 1).

2014 PGVA Methodology

5. The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada PipeLine Limited ("TCPL") firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded monthly in the PGVA.

6. The fixed cost component of the TCPL firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized long haul

TCPL ("FT") transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual long haul TCPL Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA. However, due to the uncertainty arising from the most recent TCPL decision, the Company is proposing a change for 2014. If the Company enters into alternative arrangements that allow it to satisfy its Peak Day Design Criteria Demand prior to the start of the fiscal year then the Company would propose that if these alternative arrangements impact the amount of forecasted UDC then the Company will amend its forecast and bring forward any changes as part of the January 2014 QRAM.

7. Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TCPL tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized long haul TCPL transportation capacity will also be recorded in the PGVA. The inclusion of changes in TCPL tolls in the PGVA is consistent with past practice.

8. Since the transportation tolls for the Alliance and Vector pipelines that were used in the determination of the PGVA reference price were based on an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

9. Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TCPL tolls will be recorded in the PGVA as a separate adjustment.

10. For the period January 1 to December 31, 2014, expenditures related to TCPL's Storage Transportation Services, including balancing fees related to TCPL's Limited Balancing Agreement, will be recorded in the 2014 PGVA. The PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

11. The PGVA will record adjustments related to Transactional Services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2014 PGVA and 2014 TSDA for purposes of deferral account dispositions.

12. In addition, the 2014 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

13. The 2014 PGVA will also record an inventory valuation adjustment every time a recalculated “Utility Price” or PGVA Reference Price comes into effect at the beginning of a quarter within the fiscal year. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

14. The 2014 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

15. The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

16. The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA for each fiscal year.

17. Simple interest is to be calculated on the opening monthly balance of the 2014 PGVA at the approved short-term debt interest rate.

2014 Design Day Criteria Transportation Deferral Account ("2014 DDCTDA")

18. The Company has prepared its 2014 Gas Cost budget inclusive of the impact of the increased requirements resulting from the update of the Peak Gas Design Day Criteria approved by the Board in EB-2011-0354, to be phased in equally over the 2013 and 2014 fiscal years. Consequently, the DDCTDA is not required for fiscal years beyond 2014.

Witnesses: K. Culbert
D. Small

19. The purpose of the proposed 2014 DDCTDA is to record the actual cost consequences of unutilized transportation capacity contracted by the Company to meet increased requirements resulting from the Approved changes in the Peak Gas Design Day Criteria.

20. Simple interest is to be calculated on the opening monthly balance of the 2014 DDCTDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Transactional Services Deferral Account ("2014-2018 TSDA")

21. The proposal for the 2014-2018 TSDA is to record the incremental ratepayer share of net revenue from transportation and storage related Transactional Services, to be shared 90/10 between EGD's ratepayers and shareholders.

22. While the Company plans to continue to include a forecast of $12.0 million in Transactional Services revenue as an offset to rates, the Company is proposing a change to the derivation of amounts in the TSDA. Given the recent NEB changes within TCPL tolls and unknowns within the future prices and potential related impacts, EGD is proposing an updat to the TSDA methodology and scope. In the event that the ratepayer share of 2014-2018 TS net revenue exceeds $12.0 million, then such amounts over $12.0 million will be credited to the TSDA. In the event that the ratepayer share of 2014 TS net revenue is less than $12.0 million, then EGD will be credited with the difference between the actual ratepayer share of 2014-2018 TS net revenue and $12.0 million. This is a change from the 2013 TSDA. Currently the

maximum credit to Enbridge is $ 4.0 million. The Company is proposing that there be no cap on the amount being credited to Enbridge should the ratepayer share of TS net revenue be less than $12.0 million.

23. Simple interest is to be calculated on the opening monthly balance of the 2014-2018 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Unaccounted for Gas Variance Account ("2014-2018 UAFVA")</u>

24. The purpose of the 2014-2018 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of Unaccounted for Gas ("UAF") and the Board approved UAF volumetric forecast. The Company proposes that for each of these fiscal years, the UAF volume variance calculation will measure each fiscal year's actual UAF against the UAF volume forecast.

25. The gas costs associated with the UAF variance will be calculated at the end of each calendar based on the estimated volumetric variance between the Board approved level of UAF for the subject year and the then-current estimate of the UAF for that year. This amount will be included within the UAF for the subject year. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF used within the prior year's UAFVA and actual UAF experienced for that year.

26. The UAF annual variance would then be allocated on a monthly basis in proportion to actual sales and the related cost would be calculated using the monthly PGVA reference price.

27. Carrying costs for the UAFVA will be calculated using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Storage and Transportation Deferral Account ("2014-2018 S&TDA")

28. The purpose of each of the 2014-2018 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the Company.

29. The S&TDA for each fiscal year will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

30. The S&TDA for each fiscal year will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

31. Simple interest is to be calculated on the opening monthly balance of each of the 2014-2018 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Deferred Rebate Account (“2014-2018 DRA”)</u>

32. The Company proposes to establish a DRA for each of 2014-2018, to record any amounts payable to, or receivable from, customers of the Company as a result of the clearing of deferral accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers. The account will also include amounts arising from differences between actual and forecast volumes used for the purpose of clearing deferral account balances.

33. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Customer Care Services Procurement Deferral Account (“2014-2018 CCSPDA”)</u>

34. The costs approved for recovery in rates by the EB-2011-0226 Decision included Enbridge’s major customer care outsourcing and internal O&M costs in addition to the remaining capital and related costs associated with the Enbridge Customer Information System (“CIS”)that was implemented in September 2009.

35. The two major outsourced customer care agreements addressed in the EB-2011-0226 proceeding will reach their normal expiry dates as on

December 31, 2017 subject to extension rights available to the Company. The Company is planning on conducting benchmarking and tendering processes with respect to the services conveyed via these agreements beginning in 2014. As such, the Company requests that a new deferral account be established, the Customer Care Services Procurement Deferral Account ("CCSPDA"), to be in effect /u for 2014, 2015 and 2016 to capture the costs associated with the benchmarking, tendering and potential transition of customer care services to new service provider(s). The Company would then bring the costs recorded in this account for recovery in rates in 2017. Further details are provided in the Customer Care Services Procurement Deferral Account evidence at Exhibit D1, Tab 8, Schedule 4.

36. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Customer Care / CIS Rate Smoothing Deferral Account ("2014-2018 CCCISRSDA")</u>

37. The CCCISRSDA is required for each of these years to capture the difference between the forecast customer care and CIS costs versus the amount to be collected in revenues. This approach was approved by the Board in the EB-2011-0226 CIS Customer Care Settlement Agreement and proceeding. The amount to be debited or credited to the deferral account for 2014 and for each subsequent year through 2018, will be calculated by multiplying the difference in cost per customer and smoothed costs per customer, times the updated customer forecast for the year. The balances in the account will not be cleared during the 2014 through 2018 period. The balance will build up during the years 2013 to 2015

when the cost per customer exceeds the smoothed cost per customer being collected in rates, and then the balance will be drawn down during the years 2016 to 2018 when the cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account it is to be cleared along with the clearance of other 2018 deferral and variance accounts.

38. As determined in the EB-2011-0226 Settlement Agreement, interest is to be calculated on the balance of this account at a fixed annual rate of 1.47%, and will not change during the period the deferral account is allowed to continue through 2018. The interest carrying charges will be disposed of annually at the same time of clearance of all other deferral and variance accounts.

<u>2014-2018 Average Use True Up Variance Account ("2014-2018 AUTUVA")</u>

39. The purpose of the AUTUVA for each of these fiscal years is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism ("LRAM"), extended by the average use volume variance per customer and the number of customers.

40. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of

this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Greenhouse Gas Emissions Impact Deferral Account ("2014-2018 GGEIDA")

41. The purpose of the GGEIDA for each of these years is to record amounts associated with any and all impacts of potential Provincial and or Federal regulations in relation to Greenhouse Gas Emission requirements effected onto EGD during these fiscal years along with the impacts resulting from the sale of or other dealings in earned carbon dioxide offset credits. EGD has provided the context for the potential regulation changes in relation to greenhouse gas emissions in Exhibit D1, Tab 8, Schedule 5.

42. EGD is proposing that this new account will take the place of the account which was formerly intended to deal with the potential impacts of any dealings in earned carbon dioxide offset credits which was called the Carbon Dioxide Offset Credits Deferral Account ("CDOCDA"). The CDOCDA was originally approved by the Board in its Natural Gas Generic DSM proceeding, EB-2006-0021.

43. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Earnings Sharing Mechanism Deferral Account ("ESMDA")

44. The purpose of the ESMDA is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. If the actual utility

return on equity, calculated on a weather normalized basis, is more than 100 basis points over the level of ROE determined by the application of the Board's ROE Formula, the resultant earnings amount above 100 basis points will be shared equally (i.e., 50/50) between the Company's ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application. In addition, the following shareholder incentives and other amounts are outside of the ambit of the earnings sharing mechanism: amounts related to the Shared Savings Mechanism ("SSM") and Lost Revenue Adjustment Mechanism ("LRAM"), amounts related to Transactional Services incentives, amounts related to Open Bill program incentives, and amounts related to Electric Program Earnings Sharing incentives. The ESM is non-symmetrical, such that ratepayers will not be responsible for sharing any level of under-earnings.

45. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Manufactured Gas Plant Deferral Account ("2014-2018 MGPDA")</u>

46. The Company is proposing to establish a MGPDA for each fiscal year of the IR term in order to capture all costs incurred in managing and resolving issues related to the Company's Manufactured Gas Plant ("MGP") legacy operations. Amounts recorded in the 2013 MGPDA will be transferred to the 2014 MGPDA. Costs charged to the

account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company's responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company's existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

47. The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

48. Simple interest is to be calculated on the opening monthly balance of the MGPDA in each fiscal year using the Board approved EB-2006-0117 interest rate methodology. The balance of this account together with carrying charges will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Gas Distribution Access Rule Impact Deferral Account (“GDARIDA”)

49. The purpose of the GDARIDA is to record all incremental unbudgeted capital and operating impacts associated with the development, implementation, and operation of the Gas Distribution Access Rule and any ongoing amendments to the rule. Such impacts would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs or revenue changes in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

50. The GDARIDA was formerly approved as and known as the Gas Distribution Access Rule Cost Deferral Account, (“GDARCDA”). The Company is proposing a slight alteration of the scope of the account, which is to include all impacts which could arise as a result of ongoing changes in GDAR. As an example, in 2011, the Board approved an amendment to GDAR which prospectively required a change in the manner in which late payment penalties (“LPP”) and related revenue was applied (exempting the application of LPPs in certain situations where they had previously applied). This amendment meant that the manner and level of which LPP revenue was embedded as an offset to EGD’s rates at the outset of its first Generation IR term was too high relative to the level of LPP revenue which would be recovered in 2012 from late paying customers. To address such situations in future years, without knowing what further amendments to GDAR might come about between 2014 and 2018, EGD is proposing that the account is more properly scoped to include all impacts of any amendments to GDAR as opposed to simply including cost related impacts.

51. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2014-2018 Ontario Hearing Costs Variance Account ("2014-2018 OHCVA")

52. The purpose of the OHCVA for each of these years is to record the variance between actual rate proceeding and other proceedings, activities and related expenses and the budgeted level of $8 million for 2014, $6 million for 2015, and $6 million for 2016 contained within this 2014-2018 rate application.

53. Simple interest will be calculated on the opening monthly balance of the account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2014-2018 Electric Program Earnings Sharing Deferral Account ("2014-2018 EPESDA")

54. The Company will continue the EPESDA for 2014 to 2018 under the same parameters as established and approved within the 2013 EB-2011-0354 proceeding. The account will be used to track and account for the ratepayer's 50% share of net revenue generated by DSM services provided under contract to the OPA and electric LDCs. Net revenue is determined, using fully allocated costs, as was determined is the DSM guidelines proceeding EB-2008-0346.

55. Simple interest will be calculated on the opening monthly balance of the account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2014-2018 Open Bill Revenue Variance Account ("2014-2018 OBRVA")

56. The purpose of the OBRVA is to track and record the ratepayer share of net revenue for Open Bill Services. The account as currently approved for 2013, allows for net annual revenue amounts in excess of $5.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. Within the Open Bill Access Services EB-2013-0099 application and proceeding EGD is proposing to update the terms of the OBRVA. The proposed updated terms are that in the event that net revenues fall below $4.889 million in any one Enbridge fiscal year, then in the remaining fiscal years up to and including the final year of Enbridge's 2nd Generation IR term (2014-2018), Enbridge will be entitled to a credit equal to the total shortfall between actual net revenues and $5.389 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

57. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Witnesses: K. Culbert
D. Small

<u>2014-2018 Ex-Franchise Third Party Billing Services DA ("2014-2018 EFTPBSDA")</u>

58. The purpose of the EFTPBSDA is to record and track the ratepayer share of revenues generated from third party billing services provided to ex-franchise parties net of incremental costs associated with the services. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

59. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Constant Dollar Net Salvage Adjustment Deferral Account ("2014-2018 CDNSADA")</u>

60. The CDNSADA is being proposed by the Company in conjunction with the Depreciation Study review and proposal being made in this case. The depreciation study filed at Exhibit D2, Tab 1, Schedule 1 proposes implementing the constant Dollar Net Salvage method to calculate site restoration cost requirements. As explained at Exhibit D1, Tab 5, Schedule1 this results in a reduction to the net salvage value or depreciation reserve liability recorded on EGD's books of $259.8 million.

61. EGD is proposing this deferral account as the means of recording and clearing annual credit amounts to ratepayers over each of fiscal years 2014 through 2018. The proposal is to clear the following annual amounts, 2014 - $68.1 million, 2015 -

$63.1 million, 2016 - $58.1 million, 2017 - $53.1 million and 2018 - $17.4 million. This proposed pattern of clearance was determined in conjunction with the Company's expert, Gannett Fleming. In addition, EGD also considered the impact of the revenue requirements, coming out of the five year 2014-2018 period, and determined that a greater portion of the balance being cleared in that time frame could help mitigate the bill impacts, to a degree, arising from capital requirements of EGD during the period.

62. Additionally, for each year, EGD will determine the annual amount actually cleared to ratepayers versus the amount the Company proposed were to be cleared. The difference between those amounts will be included within a future year CDNSADA as a debit or credit. The result will be that the projected remaining un-cleared amount would be adjusted annually to ensure that the total amount cleared through the use of this account, upon true up post 2018, would equal the proposed clearance of $259.8 million.

63. The $259.8 million is currently recorded in a liability account which for utility rate base determination purposes is accounted for as an offset against property, plant and equipment. EGD proposes to transfer the total amount to this deferral account and clear amounts on a monthly basis beginning in January of 2014 through December of 2018, through a rate rider as shown and explained in evidence at Exhibit H1, Tab 1, Schedule . EGD proposes and has calculated rate base for the 2014 through 2016, in a manner which debits the deferral account each and every month by the amount to be cleared out of the $259.8 million which results in a required and equal monthly value increase to rate base during these years. This treatment will continue for rate base determinations in 2017 and 2018.

Witnesses: K. Culbert
D. Small

64. Due to the nature of the proposed treatment of this deferral account, which is that the balance in the account will serve as an offset to rate base while it is being cleared through the proposed rate rider to be in effect for 2014 through 2018, EGD proposes that no interest is required to be calculated for this account.

<u>2014-2018 Transition Impact of Accounting Changes DA ("2014-2018 TIACDA")</u>

65. The TIACDA is required to track and record the remaining un-cleared balances associated with Other Post Employment Benefit "("OPEB") amounts in respect of which the Board approved recovery within the EB-2011-0354 proceeding. In that proceeding, the Board approved recovery of an original estimated amount of $90 million evenly at an amount of $4.5 million over 20 years commencing in 2013. The final estimate which EGD recorded in the TIACDA at the end of 2012 was $88.7 million, which EGD will clear evenly over 20 years commencing in 2013. EGD is requesting clearance of $4.4 million in 2013 within its ESM and deferral and variance account review proceeding EB-2013-0046. The same amount will be cleared in subsequent years, including 2014 to 2018.

66. Interest is not applicable to the balance of this account.

<u>2014-2018 Post-Retirement True-Up VA ("2014-2018 PTUVA")</u>

67. The purpose of the PTUVA is be to record the differences between the forecast pension and other post-employment benefit expenses ("OPEBs") of $37.3 million for 2014, $33.8 million for 2015, and $30.9 million for 2016 included within each of those year's forecast Allowed Revenue amount. The annual estimate details and support are found in evidence in Mercer reports filed as Appendices to Exhibit D1, Tab 16, Schedule 1.

68. EGD proposes that, as part of the annual rate adjustment proceedings for 2015 and 2016, it will provide updated forecasts of pension and OPEBs costs for the subject year, which forecast will replace the original forecast within the Allowed Revenue amount for the subject year. The Company believes that this should mitigate the amount of any annual variances.

69. EGD proposes that the 2014 to 2018 PTUVA will operate in a manner that is similar to the manner in which the 2013 PTUVA operates. That is, any variances between forecast and actual expenses will be recorded and cleared from the 2014-2018 PTUVA subject to the condition that any amount in excess of $5 million (credit or debit) will be transferred into a next year's account, so that large variances can be cleared over time. Under this approach, the maximum amount that will be cleared from each annual PTUVA would be $5 million and any remaining amount from each year's PTUVAs would be transferred to a next year PTUVA for future clearance.

70. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>DSM Related Variance Accounts (3)</u>

2014-2018 Demand Side Management Variance Account ("2014-2018 DSMVA"),
2014-2018 Lost Revenue Adjustment Mechanism Variance Account ("2014-2018 LRAM"),
2014-2018 Demand Side Management Incentive Deferral Account ("2014-2018 DSMIDA")

71. The Company currently has three DSM related deferral and variance accounts for 2014 as approved by the Board in EGD's 2013, EB-2011-0354 rate proceeding and as described and scoped within the Demand Side Management Guidelines for Natural Gas Utilities EB-2008-0346, EB-2011-0295 and EB-2012-0394 DSM related proceedings. The Company proposes to establish that same group of DSM related deferral and variance accounts for 2015 through 2018 but has not yet received direction from the Board in that regard. Additionally, EGD is proposing that any further variances in DSM spending and results, beyond those included within the 2014-2018 forecasts, which occur as a result of Board decisions in any other proceeding or docket be included within each of the 2014-2018 DSM variance accounts. EGD has included the approved or projected level of DSM spending in each of its 2014-2018 forecasts of costs.

72. Simple interest is to be calculated on the opening monthly balance of these accounts using the Board Approved EB-2006-0117 interest rate methodology. The balances in these accounts, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2015-2018 Greater Toronto Area Project Variance Account ("2015-2018 GTAPVA")</u>

73. The purpose of this variance account is to track and record the variance which may occur annually between the forecast GTA related Allowed Revenue embedded within EGD's overall Allowed Revenue amounts in this rate application and the eventual actual GTA related Allowed Revenue amounts which occur in each of 2015 through 2018, once the actual impacts of the project are known. Details of the planned GTA project and the proposed variance account are found in evidence at Exhibit D1, Tab 8, Schedule 2.

74. Simple interest is to be calculated on the opening monthly balance of these accounts using the Board Approved EB-2006-0117 interest rate methodology. The balances in these accounts, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Criteria for Establishment of Deferral and Variance Accounts

75. The criteria adopted by the Company in determining when to come forward for a rate order or an accounting order request for a deferral or variance account includes the following considerations:
    - the materiality of the amount at risk (revenue or expense);
    - protection of the ratepayer or the shareholder from benefitting at the expense of the other party related to a variance in the forecast amount;
    - the level of uncertainty associated with a forecast of the amount at risk; and
    - the aspect of control - are the underlying circumstances beyond the Company's ability to control.

UPDATED DEFERRAL ACCOUNT EVIDENCE

Unabsorbed Demand Costs Deferral Account (UDCDA) and DDCTDA

76. As described in its updated gas cost evidence at Exhibit D1, Tab 2, Schedule 1, the Company intends to contract for incremental one year long haul FT capacity on TCPL to meet its Peak Day requirements in 2014. A consequence of contracting for incremental long haul capacity is the possibility of Unabsorbed Demand Charges ("UDC").

77. To the extent that the Company is unable to utilize 100% of its contracted long haul TCPL FT capacity to meet customer demand and/or fill storage then the associated UDC costs will be debited in the UDCDA deferral account (excluding the amounts that will be captured in the DDCTDA – please refer to the Updated Exhibit D1, Tab 2, Schedule 1). Enbridge's forecast of UDC costs for 2014, excluding amounts that may be recorded within the 2014 DDCTDA, is $62.8 million. That is the maximum amount that may be recorded within the 2014 UDCDA.

78. Enbridge will use its best efforts to mitigate the UDC that would otherwise be recorded in the 2014 DDCTDA and the 2014 UDCDA. For example, Enbridge will use transportation capacity to fill storage (by displacing discretionary purchases of gas at Dawn) where that is reasonably possible, to reduce the total amount of unutilized capacity. Where there is unutilized capacity, Enbridge will make best efforts to assign that capacity to third parties, to mitigate the UDC costs. The outcome of Enbridge's best efforts to mitigate UDC will be reflected in the amounts recorded in the 2014 DDCTDA and the 2014 UDCDA.

79. Simple interest is to be calculated on the opening balance of this account at the approved short-term debt interest rate.

Witnesses: K. Culbert
D. Small

80. In order to keep the Board and interested parties informed as to the total unutilized transportation costs the Company intends to provide the actual balance in the UDCDA and DDCTDA and the applicable interest through the QRAM process.

81. The Company proposes that as part of the April 2015 QRAM (or subsequent QRAM depending upon the clearance of the 2014 ESM) to clear the 2014 balance in the UDCDA and DDCTDA either through a onetime charge or over the subsequent 12 months which is consistent with the clearance of PGVA balances.

Witnesses: K. Culbert
D. Small

RELOCATION MAINS VARIANCE ACCOUNT ("RLMVA")

82. As described in its Updated Rate Adjustment Process evidence filed at Exhibit A2, Tab 3, Schedule 1, the Company is now proposing to eliminate Phase I of the 2017 Rate Adjustment Application (through which capital spending requirements for 2017 and 2018 were to be set), and instead plans to set Allowed Revenue for all years of the IR term in this proceeding.

83. As part of the updated Customized IR Plan, the Company is proposing this variance account for 2017 and 2018 to address the unpredictable capital costs in relation to relocation mains requirements beyond fiscal 2016.

84. The evidence explaining the proposed manner in which the account will operate is filed in evidence at Exhibit D1, Tab 8, Schedule 6.

Witnesses: K. Culbert
D. Small

REPLACEMENT MAINS VARIANCE ACCOUNT ("RPMVA")

85. As described in its Updated Rate Adjustment Process evidence filed at Exhibit A2, Tab 3, Schedule 1, the Company is now proposing to eliminate Phase I of the 2017 Rate Adjustment Application (through which capital spending requirements for 2017 and 2018 were to be set), and instead plans to set Allowed Revenue for all years of the IR term in this proceeding.

86. As part of the updated Customized IR Plan, the Company is proposing this variance account for 2017 and 2018 to address the unpredictable costs in relation to replacement mains requirements in fiscal 2017 and 2018 that are identified through pipeline inspection activities.

87. The evidence explaining the proposed manner in which the account would operate is filed in evidence at Exhibit D1, Tab 8, Schedule 6.

Witnesses: K. Culbert
D. Small

UPDATED PROPOSED GTA PROJECT VARIANCE ACCOUNT

Overview

1. The purpose of this evidence is to explain the variance account which the Company is proposing to be attached to or coincident with the GTA project. As a result of the Company's proposed Updated Rate Adjustment Process as outlined in evidence at Exhibit A2, Tab 3, Schedule 1, the GTAPVA is now required for the years 2014 to 2018 within this rate application.

2. The GTA project rationale is filed within EGD's EB-2012-0451 Leave to Construct Application currently before the Board. Attached as Appendix A to this Exhibit (to be updated by early January 2014), EGD has provided the forecast allowed revenue amounts of the total GTA project for each of 2014-2018, using the GTA project costs and timing assumptions[1](excluding gas cost forecasts and impacts) as embedded within EGD's overall Allowed Revenue for these years.

3. EGD is proposing that this variance account will be used to report any variance between the forecast Allowed Revenue in Appendix A and the eventual actual Allowed Revenue which will be known upon completion of the project. The Company proposes that the Allowed Revenue variance impact for the fiscal years 2015 through 2018 be recognized within the variance account with an offsetting annual entry through revenue in each year, with the cumulative impact at the end of each of 2015 to 2018 to be cleared through a rate rider along with any and all other deferral or variance accounts for the subject year.

[1] The GTA project timing and costs used within the revenue requirements provided are those used within the responses to interrogatories within the GTA LTC proceeding (EB-2012-0451) which assume Segment A's Bram West to Albion is a 36" pipeline with a 50/50 sharing agreement with TCPL.

Witnesses: K. Culbert
C. Fernandes

4. The scale of the GTA project results in the normal forecasting variance of costs potentially being large in an absolute sense. With the forecast of capital costs being $580.9 million (shown in attached Appendix G) even a modest forecast variance could result in a risk to both the ratepayers or the Company of a significant over or under payment and recovery of Allowed Revenue over the 2015 through 2018 fiscal years, which is the principal rationale for the requested variance account.

5. The GTA project consists of two Segments, A[2] and B, which are projected to have construction commence in 2014 / 2015 with an in service date of October 2015. Please refer to the following exhibits filed in the GTA Leave to Construct Application (EB-2012-0451), in order to provide the project details which underpin and support the total GTA project forecast 2014-2016 Allowed Revenue scenarios provided herein at Exhibit C1, Tab 5, Schedule 1, on Appendices A to E:
   - Purpose, need and timing filed as Exhibit A, Tab 3, Schedule 1;
   - Natural Gas Demand, Supply & Expected Benefits filed as Exhibit A, Tab 3, Schedule 5;
   - Proposed Facilities, Operation & System Benefits filed as Exhibit A, Tab 3, Schedule 6;
   - Timing filed as Exhibit A, Tab 3, Schedule 8;
   - Total Estimated Project Cost filed as Exhibit C, Tab 2, Schedule 1;
   - Proposed Construction Schedule filed as Exhibit C, Tab 2, Schedule 2;
   - Arrangement with TransCanada filed as Exhibit E, Tab 1, Schedule 2.

6. EGD has also provided, as Appendix B (to be updated by 2013-12-17), the forecast Allowed Revenue impact of the shared Segment A BramWest to Albion pipeline portion of the overall project as embedded within the EGD overall Allowed Revenue for 2014-2018. EGD proposes to treat the shared Segment A BramWest to Albion pipeline as a separate cost center where a rate (332) will be developed on a cost-of-service basis. Rate 332 would recover the Allowed Revenue associated with any approved ratio of the shared Segment A BramWest to Albion pipeline and would

[2] Same as footnote 1.

exist over the agreed contractual terms with sufficient termination provisions to ensure any unrecovered capital amounts are not unduly cross-subsidized by EGD ratepayers.

7. The Allowed Revenue for the shared Segment A BramWest to Albion pipeline as shown in Appendix B includes the associated cost of capital, O&M, depreciation, and related taxes that occur in each of fiscal years 2015 to 2018.

PIPELINE INTEGRITY & ENGINEERING – O&M BUDGET

1. This exhibit outlines the Company's Pipeline Integrity & Engineering ("PI&E") department's O&M budget for the 2014, 2015 and 2016 fiscal years.

Mandate and Responsibilities

2. Industry events such as the natural gas explosion in San Bruno, California (2010) and Enbridge's oil spill in Marshall, Michigan (2010), and the recent responses and expectations from regulatory bodies, as well as the Technical Standards and Safety Authority Code ("TSSA") 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 Enbridge's growing focus upon efforts to reduce operational risks, with a goal of reducing (and ideally eliminating) incidents and injuries of workers and the public.

3. Enbridge's PI&E department is accountable and responsible for the design and assessment of condition monitoring of the distribution system, identifying plans required to add customers and load, and remediate risks, and for establishing construction, operations and maintenance standards which meet or exceed technical and regulatory requirements.

Department Structure

4. The PI&E department is organized into the following four groups: i) Integrity, ii) Engineering, iii) Distribution Asset Management, and iv) Quality and Training. The responsibilities of each group are discussed in turn below.

Witnesses: J. Briggs
A. Creery
L. Lawler

5. *Integrity*: This group is accountable for the condition-monitoring and mitigation of pipelines and other assets within the distribution system. The sub-groups and their responsibilities are as follows: a) Damage Prevention – administers the Company's damage prevention programs including provision of locates, safe excavation awareness programs and sewer safety inspections. Also, this group has been heavily involved with the development of regulations for Bill 8, the *Ontario Underground Infrastructure Notification System Act* which was passed into law in 2012; b) Leak Management – administers the Company's leak survey programs, and identifies and prioritizes leaks for repair; c) Corrosion Management – administers corrosion prevention programs, which involves methods to prevent, monitor and mitigate corrosion on the distribution system; d) Transmission Integrity – administers the Company's in-line inspection and assessment program for higher stress pipelines (i.e. pipelines operating at or over 20% of their Specific Minimum Yield Strength (SMYS)); e) Distribution Integrity – evaluates the integrity of the remainder of the Company's assets (i.e. pipelines operating below 20% SMYS) through damage and failure analysis and conducting studies on assets; f) Asset Integrity Strategy and Risk Analysis, establishes risk evaluation methodologies and conducts risk analysis on aspects of the system, ensures data integrity and produces the System Integrity and Reliability section of the 10 year iterative Asset Plan.

6. *Engineering*: This group is accountable for ensuring technical compliance with applicable regulations, codes and standards, and participates in industry associations and committees to keep up-to-date on requirements, and to maintain relationships with industry stakeholders and regulators. The subgroups and their responsibilities are as follows: a) Engineering Construction and Maintenance – establishes and maintains policies, procedures and standards for the design,

construction, operation and maintenance of the distribution system; b) Measurement and Regulation – designs stations for measurement and regulation of natural gas in the system; c) Process Safety – ensures the elements of process safety management, a comprehensive framework to assess and manage operational risks, are established and managed in the Company; d) Distribution Technology - participates in research consortiums for developing new technologies for preventing and detecting threats (e.g. damages) on the system. Also, this group works with Operations and Integrity to understand issues and find technology solutions; e) Engineering Material and Evaluation Centre - identifies and approves the use of materials, products and tools in the gas distribution system. It also investigates material faults, and assists in quality assurance evaluations and incident investigations.

7. *Distribution Asset Management*: This group is accountable for ensuring the overall design of the distribution system is capable of meeting the Company's gas delivery requirements. This involves consideration of load growth, system integrity demand requirements, and compliance with municipal and regulatory requirements. The subgroups and their responsibilities are as follows: a) Records Administration – checks and maintains all asset records for accuracy and integrity; b) System Analysis and Design – conducts load modeling to identify reinforcement requirements and determines impacts of project work on system capacity and delivery capabilities, and provides alternatives; c) Area Planning and Design - ensures that the design and drafting components of construction and maintenance plans for distribution facilities are undertaken in a timely and cost effective manner; d) Asset Systems – maintains Geographical Information System (GIS) for asset information to ensure accessibility and accuracy of information; e) Land Services – oversees acquisition and disposal of real estate assets and municipal property tax obligations; f) Asset Plan – produces the annual iterative 10-year Asset Plan.

Witnesses: J. Briggs
A. Creery
L. Lawler

8. *Quality and Training*: This group is accountable for quality assurance programs; training workers to perform such work; ensuring external parties performing work are adequately insured; and ensuring measurement requirements are met. The subgroups and their responsibilities are as follows: a) Quality Assurance and Incident Investigations – oversees quality assurance programs, and conduct incident investigations. The group follows-up on findings to ensure they are closed out, for continuous improvement; b) Technical Training – develops and delivers classroom and practical hands-on training on critical tools, equipment and procedures. It also delivers TSSA accredited programs, and other industry specific technical programs to Enbridge employees and contractors (e.g. Gas Performance Inspector school). To help ensure a competent, skilled and safe workforce, the group also provides tools and training related to competency management programs; c) System Measurement – manages programs involving accreditation of meters for customer installations and meter exchanges, which are requirements overseen by Measurement Canada; d) Risk and Claims – monitors and manages the sufficiency of insurance coverage of contractors performing work, and investigates and settles claims made against the company.

<u>2013 to 2016 O&M Budget</u>

9. Table 1 below summarizes PI&E's O&M budget for 2013 through 2016. The budget is a consolidation of the requirements of the four individual groups which make up the PI&E department.

TABLE 1
Enbridge Gas Distribution Inc.
Operation and Maintenance by Cost Type
Pipeline Integrity & Engineering 2013 to 2016 Budget

Line No.	Particulars (000's)	Budget 2013	Budget 2014	Budget 2015	Budget 2016
1	Gross Salaries and Wages	$ 32,267	$ 32,977	$ 33,711	$ 34,473
2	Capitalization of Salaries and Wages	(20,179)	(20,623)	(21,082)	(21,558)
3	Total Labour	$ 12,089	$ 12,354	$ 12,629	$ 12,915
4	Employee Training and Development	296	304	306	313
5	Materials and Supplies	1,299	1,051	1,066	1,097
6	Outside Services	22,881	23,215	23,890	24,191
7	Consulting	357	435	469	510
8	Repairs and Maintenance	103	104	106	109
9	Fleet	701	710	735	764
10	Rents and Leases	1,436	1,711	1,662	1,932
11	Travel and Other Business Expenses	601	615	632	649
12	Memberships	77	80	81	83
13	Claims, Damages and Legal Fees	863	940	963	974
14	Internal Allocations and Recoveries	(2,538)	(2,514)	(2,665)	(2,761)
15	Total	$ 38,164	$ 39,004	$ 39,874	$ 40,775
	FTEs	430	430	430	430

10. Of the total budget each year, approximately 63% is for Integrity; 9% is for Engineering; 7% is for Distribution Asset Management; and 21% is for Quality and Training.

11. Of the total budget each year, approximately $12.0 million or 32% accounts for *Salaries and Wages*; 61% accounts for *Consulting*, *Outside Services* (i.e. contractor costs for locates and integrity inspections), and *Rents and Leases* (i.e. right-of-ways and easements); and 7% accounts for *Materials*, *Fleet*, and *Other Expenses*.

Witnesses: J. Briggs
A. Creery
L. Lawler

Cost Drivers

12. With the Company's heightened focus on reducing operational risk and associated incidents and injuries, the significant cost drivers for PI&E in 2014 to 2016, in addition to inflationary pressures on salaries and wages, are: i) increases in locate volumes, ii) new and expanded damage prevention programs, iii) new and expanded integrity inspections and assessments on higher stress pipelines, iv) expanded leak survey, and iv) technical training.

13. Forecast spending within the Integrity group (which accounts for approximately 63% of the overall PI&E budget), includes the following:

    a. Activities by the Damage Prevention sub- group accounts for approximately $14.5 million or 37.4% of the overall budget each year. Of this amount, the /u
    delivery of locates to third parties accounts for approximately $13.05 million. /u
    The remaining budget is for programs to reduce third party damages, and Company inspection and oversight of third party locators, high risk excavations, sewer safety programs, and aerial patrols.

    b. Activities by the Transmission and Distribution Integrity sub-groups account for approximately $5.3 million or 14.1% of the overall budget each year. These dollars will be used to conduct integrity assessments, primarily in-line inspections, with state of the art intelligent tools which find crack, metal loss, and mechanical damages on Enbridge's higher stress pipelines.

    c. Activities by the Corrosion and Leak Management sub-groups account for approximately $4.5 million or 11.8% of the overall budget each year. Corrosion monitoring and mitigation will continue. In addition to regular and required leak surveys, increased surveys focused on assets and areas of higher risk are planned over the 2014 to 2016 period.

14. Forecast spending within the Quality and Training group (which accounts for approximately 21% of the overall PI&E budget), includes the following:

    a. Activities by the Technical Training group account for approximately $3.8 million or 10% of the overall budget each year. Enhancements to training programs and delivery will continue through use of the new Technology and Operations Centre.

    b. Additionally, System Measurement accounts for approximately $2.4 million or 6%, Risk and Claims accounts for $1.3 million or 3.4%, Quality Assurance and Incident Investigation accounts for approximately $0.38 million or 1%;

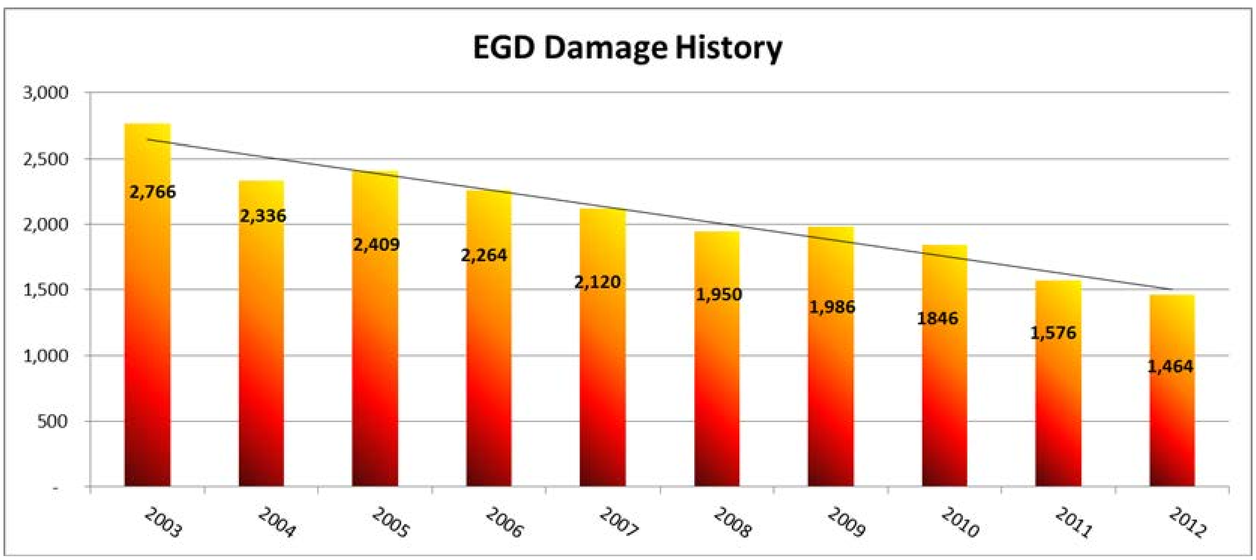
15. The remainder of the budget is for activities by: Distribution Asset Management which accounts for approximately $2.8 million or 7.3%; and Engineering which accounts for approximately $3.4 million or 9%.

16. While many of the responsibilities that must be met by the PI&E Department are not new (such as engineering, construction and maintenance standards, damage prevention, metering, technical training and leak management), the requirements in many areas are increasing.

17. In order to emphasize the increased requirements that the PI&E Department must accommodate, the following sections detail some of the emerging and growing cost drivers that the Department expects to be facing in the 2014 to 2016 term.

18. The Company's largest operational threat is third party damage to the natural gas plant. Preventing damages improves worker and public safety, as well as the integrity of distribution assets. A key prevention measure is to provide locates related to underground plant before excavations are done. The Company has been successful in reducing normalized damages per thousand locate requests as well as absolute damages, as illustrated in Figure 1 below. Forecasted damages for 2013 to 2016 are not shown because such forecasts for total damages in a given year are made during that year based on the actual results. Associated costs will be accommodated within the PI&E O+M Budget.

Figure 1



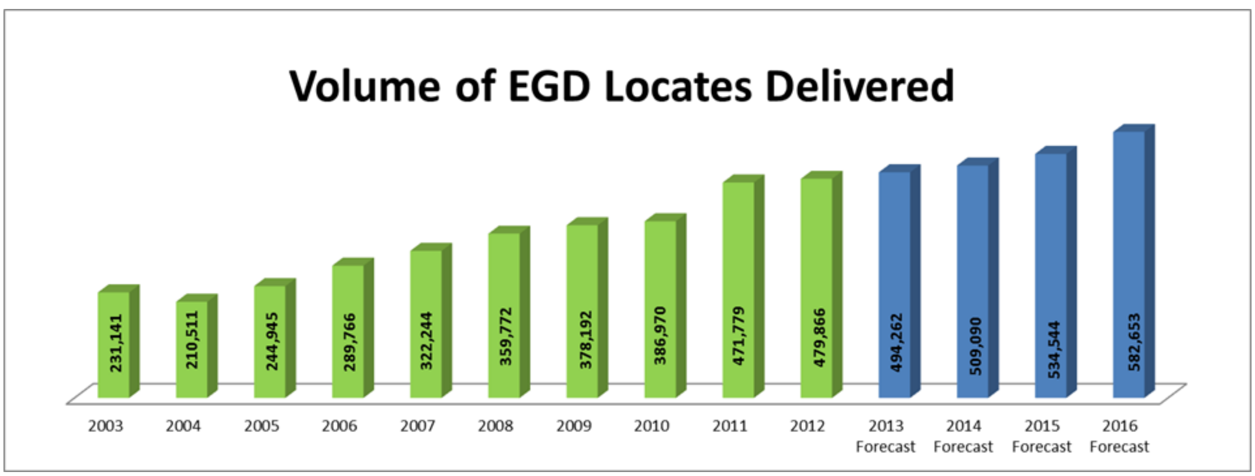
19. To reduce damages further, Enbridge played a leading role in the development and passage of Bill 8, the *Ontario Underground Infrastructure Notification System Act*. This Act, which was passed in June 2012, requires owners of underground utilities to become members of Ontario One Call (all underground utility owners must become members by June 2013, with the exception of municipalities who must

become members by June 2014). Ontario is the first province to implement this system in Canada. This mandatory system exists in all 50 U.S. states, where damages rates are significantly lower than in Ontario. The Act includes requirements such as:

- Excavators must call for locates, and members must provide locates within five (5) business days; and
- Ontario One Call must continue to raise public awareness of Ontario One Call and safe digging practices.

20. The Company expects increases in locate requests, and thus costs, as awareness and appreciation of the system increases and regulations, which are expected to be in place in 2013, are enforced. Figure 2 below illustrates the increase in locates requests over time. Currently, approximately 40% of the Company's damages are from excavations where no locate request was made.

Figure 2



21. Additionally to reduce risk and damages, Enbridge has implemented a High Risk Excavation Program. This program identifies high risk excavations based on excavator damage history; the type of excavation equipment to be used; excavation depth and methodology; the natural gas assets in the vicinity of the excavation; and the potential consequences of a damage. Company Inspectors can then proactively educate excavators on safe digging practices before the excavation begins. The program has resulted in a reduction in risk and damages, and resources are committed to this program to further enhance and promote safe excavation practices in the vicinity of buried natural gas plant.

22. The condition of underground pipelines is proactively determined through the Company's in-line inspection ("ILI") and assessment program for higher stress pipelines. This program identifies cracks, mechanical damage and metal loss, from, for instance, corrosion. Pipelines that have been inspected are re-inspected on a 7-year cycle. ILIs and assessments identify anomalies or features, which are excavated and mitigated in accordance with Company policy, which has been developed based on codes, standards, regulations and industry best practices.

23. Over time, ILI technology has evolved and become more sophisticated. Enbridge intends to invest in and use newer technology as it becomes available, resulting in a better understanding of pipeline condition, which will in turn, improve public safety and reduce risk.

24. To better detect leaks, the Company is moving from a frequency-based leak survey approach (i.e. survey assets on a five-year cycle) to a risk-based approach. This means the Company will investigate potential areas and assets more prone to leaks and will prioritize surveys accordingly. Such investigations have and will continue to

identify areas and assets where leaks are likely to occur. As a result of these efforts, the Company anticipates that survey frequencies will be modified based on assets conditions and risk, and that overall there is a need to increase leak survey frequency on assets approaching the end of their useful life (with relatively high leak frequencies).

25. These cost drivers described above will be managed within the PI&E O&M Budget. This will be a challenge, taking into account that the budget is only increasing by a level close to inflation, and given that there is no forecast increase in the number of FTEs available to undertake the anticipated increasing volume of work. Even if it is subsequently decided that a modest number of FTEs should be added, the associated costs will still have be managed within the same cost envelope. In order to manage within this cost envelope, productivity initiatives will be undertaken by the PI&E Department. These productivity measures are discussed below.

PI&E Department O&M Year-Over-Year Budget Variances

26. In 2014 the budget increases by approximately $0.84 million or approximately 2.2% over 2013 (see Table 2 below). The increase accounts for inflation.

Table 2
Enbridge Gas Distribution
Operation & Maintenance by Cost Type
Pipeline Integrity & Engineering 2014 to 2013 Budget

Line No.	Particulars (000's)	2014 Budget	2013 Budget	2014 vs 2013
1	Salaries and Wages	$ 32,977	$ 32,267	$ 710
2	Labour Capitalization	(20,623)	(20,179)	(444)
3	Net Salaries and Wages	$ 12,354	$ 12,089	$ 265
4	Employee Training and Development	304	296	8
5	Materials & Supplies	1,051	1,299	(248)
6	Outside Services	23,215	22,881	334
7	Consulting	435	357	78
8	Repairs and Maintenance	104	103	2
9	Fleet	710	701	9
10	Rents & Leases	1,711	1,436	275
11	Travel and Other Business Expenses	615	601	14
12	Memberships	80	77	3
13	Claims, Damages, and Legal Fees	940	863	77
14	Internal Allocations and Recoveries	(2,514)	(2,538)	24
15	Total	$ 39,004	$ 38,164	$ 840
	FTEs	430	430	-

27. In 2015 the budget increases by approximately $0.87 million or approximately 2.2% over 2014 (see Table 3 below). The increase accounts for inflation.

Witnesses: J. Briggs
A. Creery
L. Lawler

Table 3
Enbridge Gas Distribution
Operation & Maintenance by Cost Type
Pipeline Integrity & Engineering 2015 to 2014 Budget

Line No.	Particulars (000's)	2015 Budget	2014 Budget	2015 vs 2014
1	Salaries and Wages	$ 33,711	$ 32,977	$ 734
2	Labour Capitalization	(21,082)	(20,623)	(459)
3	Net Salaries and Wages	$ 12,629	$ 12,354	$ 275
4	Employee Training and Development	306	304	2
5	Materials & Supplies	1,066	1,051	15
6	Outside Services	23,890	23,215	675
7	Consulting	469	435	34
8	Repairs and Maintenance	106	104	2
9	Fleet	735	710	25
10	Rents & Leases	1,662	1,711	(49)
11	Travel and Other Business Expenses	632	615	17
12	Memberships	81	80	2
13	Claims, Damages, and Legal Fees	963	940	23
14	Internal Allocations and Recoveries	(2,665)	(2,514)	(150)
15	Total	$ 39,874	$ 39,004	$ 870
	FTEs	430	430	-

28. In 2016 the budget increases by approximately $0.9 million or approximately 2.3% over 2015 (see Table 4 below). The increase accounts for inflation.

Table 4
Enbridge Gas Distribution
Operation & Maintenance by Cost Type
Pipeline Integrity & Engineering 2016 to 2015 Budget

Line No.	Particulars (000's)	2016 Budget	2015 Budget	2016 vs 2015
1	Salaries and Wages	$ 34,473	$ 33,711	$ 762
2	Labour Capitalization	(21,558)	(21,082)	(476)
3	Net Salaries and Wages	$ 12,915	$ 12,629	$ 286
4	Employee Training and Development	313	306	7
5	Materials & Supplies	1,097	1,066	30
6	Outside Services	24,191	23,890	301
7	Consulting	510	469	42
8	Repairs and Maintenance	109	106	3
9	Fleet	764	735	29
10	Rents & Leases	1,932	1,662	270
11	Travel and Other Business Expenses	649	632	17
12	Memberships	83	81	2
13	Claims, Damages, and Legal Fees	974	963	11
14	Internal Allocations and Recoveries	(2,761)	(2,665)	(97)
15	Total	$ 40,775	$ 39,874	$ 900
	FTEs	430	430	-

Productivity

29. The increased focus on enhancing safety, through the many new requirements and activities outlined above, will place significant pressures on the PI&E Department. There will be particular challenges arising from the fact that FTE levels have been frozen for budgeting purposes (such that any FTE additions that subsequently materialize must be funded by savings in other areas), and budgets will only increase by a level of around inflation. Taking this into account, conducting the required incremental work can only be accomplished within the budget specified by

Witnesses: J. Briggs
A. Creery
L. Lawler

improving productivity in ways which do not sacrifice safety and compliance. While the PI&E Department has not conclusively identified all the ways that it will do this, the following are some examples of areas that are being targeted.

30. Additional costs from increased locate volumes are expected to be offset by savings due to fewer damages, and improved efficiencies from facility owners providing locates within five days. Some of these cost savings will manifest in other areas of Enbridge, such as Operations and Legal, and will be offset with reduction in associated cost recoveries (billing for damages).

31. Increases in leak survey will result in increased costs for the Integrity group, as well as in Operations emergency response and capital replacement requirements. The Company is investigating new technologies for more efficient surveying, to potentially offset some of these costs.

32. Measurement Canada's introduction of regulation SS06, combined with changes in technology and volume purchasing power, caused the Quality & Training group to review practices of repairing residential diaphragm meters. As of March 2013, the repair of 200 and 400 series diaphragm meters have been discontinued; new meters will be purchased thereby eliminating repair costs.

33. The Company also intends to explore cost recovery opportunities associated with the provision of training and/or use of the new Technology and Operations Centre within the industry.

Witnesses: J. Briggs
A. Creery
L. Lawler

COST OF CAPITAL SUMMARY

1. This evidence, in the following tables 1 through 6, shows a summary of EGD's cost of capital for each of the 2013 Board Approved, and 2014 through 2018 Fiscal Year forecasts.

Table 1
Cost of Capital Summary

Line No.		2013 Board Approved (excluding CIS)				
		Principal	Component	Cost Rate	Return	Return
		($millions)	%	%	%	($millions)
1.	Long-term debt	2,461.9	60.17%	5.80%	3.490%	142.8
2.	Short-term debt	56.7	1.39%	2.00%	0.028%	1.1
3.	Preferred shares	100.0	2.44%	3.20%	0.078%	3.2
4.	Common equity	1,472.9	36.00%	8.93%	3.215%	131.5
5.	Total	4,091.5	100.00%		6.811%	278.6

Table 2
Cost of Capital Summary

Line No.		2014 Forecast (excluding CIS)				
		Principal	Component	Cost Rate	Return	Return
		($millions)	%	%	%	($millions)
1.	Long-term debt	2,596.9	59.37%	5.57%	3.307%	144.6
2.	Short-term debt	102.3	2.34%	1.78%	0.042%	1.8
3.	Preferred shares	100.0	2.29%	2.96%	0.068%	2.9
4.	Common equity	1,574.6	36.00%	9.27%	3.337%	145.9
5.	Total	4,373.8	100.00%		6.754%	295.2

Witness: K. Culbert

Table 3
Cost of Capital Summary

Line No.		2015 Fiscal Year (excluding CIS) Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	2,918.4	61.41%	5.39%	3.310%	157.3
2.	Short-term debt	23.2	0.49%	2.75%	0.013%	0.6
3.	Preferred shares	100.0	2.10%	3.68%	0.077%	3.7
4.	Common equity	1,710.9	36.00%	9.72%	3.499%	166.3
5.	Total	4,752.5	100.00%		6.899%	327.9

Table 4
Cost of Capital Summary

Line No.		2016 Fiscal Year (excluding CIS) Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	3,367.0	61.31%	5.33%	3.268%	179.5
2.	Short-term debt	47.9	0.87%	3.35%	0.029%	1.6
3.	Preferred shares	100.0	1.82%	4.32%	0.079%	4.3
4.	Common equity	1,977.1	36.00%	10.12%	3.643%	200.1
5.	Total	5,492.0	100.00%		7.019%	385.5

Table 5
Cost of Capital Summary

Line No.		2017 Fiscal Year (excluding CIS) Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	3,515.5	61.49%	5.31%	3.265%	186.7
2.	Short-term debt	43.3	0.76%	4.30%	0.033%	1.9
3.	Preferred shares	100.0	1.75%	4.64%	0.081%	4.6
4.	Common equity	2,058.1	36.00%	10.17%	3.661%	209.3
5.	Total	5,716.9	100.00%		7.040%	402.5

Witness: K. Culbert

Table 6
Cost of Capital Summary

Line No.		2018 Fiscal Year (excluding CIS) Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	3,614.9	61.28%	5.36%	3.285%	193.9
2.	Short-term debt	60.5	1.02%	4.30%	0.044%	2.6
3.	Preferred shares	100.0	1.70%	4.64%	0.079%	4.7
4.	Common equity	2,123.7	36.00%	10.27%	3.697%	218.2
5.	Total	5,899.1	100.00%		7.105%	419.4

2. Details of the forecast debt issuances for each of the fiscal years 2014 through 2018, including forecast cost rates and debt issuance costs are included in Exhibit E1, Tab 2, Schedules 1 and 2. Evidence with respect to the return on equity included within the Allowed Revenue and revenue deficiency calculation is found in evidence at Exhibit E2, Tab 1, Schedules 1 and 2.

3. Further details of each of the elements of the capital structure and the determination of the cost of capital overall and any resulting deficiency or sufficiency in earnings are found at Exhibits E3, E4, E5, E6, & E7, Tab 1, Schedules 1, 2, 3, 4, & 5.

Witness: K. Culbert

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

Witness: K. Culbert

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.

Witness: K. Culbert

ALLOWED REVENUE
(DEFICIENCY)/SUFFICIENCY
2014 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS ($Millions)	Col. 3 CC-CIS ($Millions)	Col. 4 EGD Total ($Millions)
	Cost of Capital				
1.	Rate base	B3.T1.S1.P1	4,373.8	57.8	4,431.6
2.	Required rate of return	E3.T1.S1.P1	6.75%	6.44%	6.74%
3.			295.2	3.7	298.9
	Cost of Service				
4.	Gas costs	D3.T1.S1.P1	1,455.9		1,455.9
5.	Operation and maintenance	D3.T1.S1.P1	332.7	92.6	425.3
6.	Depreciation and amortization	D3.T1.S1.P1	250.1	12.7	262.8
7.	Fixed financing costs	D3.T1.S1.P1	1.9	-	1.9
8.	Municipal and other taxes	D3.T1.S1.P1	41.2	-	41.2
9.			2,081.8	105.3	2,187.1
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue	C3.T1.S1.P1	(40.5)	-	(40.5)
11.	Interest and property rental	C3.T1.S1.P1	0.0	-	-
12.	Other income	C3.T1.S1.P1	(0.1)	-	(0.1)
13.			(40.6)	-	(40.6)
	Income taxes on earnings				
14.	Excluding tax shield	D3.T1.S1.P3	64.3	8.7	73.0
15.	Tax shield provided by interest expense	D3.T1.S1.P3	(38.8)	(0.7)	(39.5)
16.			25.5	8.0	33.5
	Taxes on sufficiency				
17.	Gross sufficiency -w/out CC/CIS	E3.T1.S1.P1	35.1	-	35.1
18.	Net sufficiency -w/out CC/CIS	E3.T1.S1.P1	25.8	-	25.8
19.			(9.3)	-	(9.3)
20.	Sub-total Allowed Revenue		2,352.6	117.0	2,469.6
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	(2.9)	(2.9)
22.	**Allowed Revenue**		2,352.6	114.1	2,466.7
	Revenue at existing Rates				
23.	Gas sales	C3.T1.S1.P1	2,161.7	91.8	2,253.5
24.	Transportation service	C3.T1.S1.P1	224.4	18.4	242.8
25.	Transmission, compression and storage	C3.T1.S1.P1	1.8	-	1.8
26.	Rounding adjustment		(0.2)	-	(0.2)
27.	Total		2,387.7	110.2	2,497.9
28.	**Gross revenue sufficiency**		35.1	(3.9)	31.2

Witness: K. Culbert

ALLOWED REVENUE
(DEFICIENCY)/SUFFICIENCY
2015 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base	B4.T1.S1.P1	4,752.5	45.1	4,797.6
2.	Required rate of return	E4.T1.S1.P1	6.90%	6.44%	6.90%
3.			327.9	2.9	330.8
	Cost of Service				
4.	Gas costs	D4.T1.S1.P1	1,606.8	-	1,606.8
5.	Operation and maintenance	D4.T1.S1.P1	332.0	96.5	428.5
6.	Depreciation and amortization	D4.T1.S1.P1	263.9	12.7	276.6
7.	Fixed financing costs	D4.T1.S1.P1	1.9	-	1.9
8.	Municipal and other taxes	D4.T1.S1.P1	43.1	-	43.1
9.			2,247.7	109.2	2,356.9
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue	C4.T1.S1.P1	(40.9)	-	(40.9)
11.	Interest and property rental	C4.T1.S1.P1	0.0	-	-
12.	Other income	C4.T1.S1.P1	(0.1)	-	(0.1)
13.			(41.0)	-	(41.0)
	Income taxes on earnings				
14.	Excluding tax shield	D4.T1.S1.P3	48.0	8.3	56.3
15.	Tax shield provided by interest expense	D4.T1.S1.P3	(41.9)	(0.6)	(42.5)
16.			6.1	7.7	13.8
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS	E4.T1.S1.P1	(20.6)	-	(20.6)
18.	Net deficiency -w/out CC/CIS	E4.T1.S1.P1	(15.2)	-	(15.2)
19.			5.5	-	5.5
20.	Sub-total Allowed Revenue		2,546.2	119.8	2,666.0
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	(1.1)	(1.1)
22.	**Allowed Revenue**		2,546.2	118.7	2,664.9
	Revenue at existing Rates				
23.	Gas sales	C4.T1.S1.P1	2,312.5	91.8	2,404.3
24.	Transportation service	C4.T1.S1.P1	211.2	18.4	229.6
25.	Transmission, compression and storage	C4.T1.S1.P1	1.8	-	1.8
26.	Rounding adjustment		0.1	-	0.1
27.	Total		2,525.6	110.2	2,635.8
28.	**Gross revenue deficiency**		(20.6)	(8.5)	(29.1)

Witness: K. Culbert

ALLOWED REVENUE
(DEFICIENCY)/SUFFICIENCY
2016 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base	B5.T1.S1.P1	5,492.0	32.4	5,524.4
2.	Required rate of return	E5.T1.S1.P1	7.02%	6.44%	7.02%
3.			385.5	2.1	387.6
	Cost of Service				
4.	Gas costs	D5.T1.S1.P1	1,632.5	-	1,632.5
5.	Operation and maintenance	D5.T1.S1.P1	339.1	100.4	439.5
6.	Depreciation and amortization	D5.T1.S1.P1	291.2	12.7	303.9
7.	Fixed financing costs	D5.T1.S1.P1	1.9	-	1.9
8.	Municipal and other taxes	D5.T1.S1.P1	45.5	-	45.5
9.			2,310.2	113.1	2,423.3
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue	C5.T1.S1.P1	(41.2)	-	(41.2)
11.	Interest and property rental	C5.T1.S1.P1	0.0	-	-
12.	Other income	C5.T1.S1.P1	(0.1)	-	(0.1)
13.			(41.3)	-	(41.3)
	Income taxes on earnings				
14.	Excluding tax shield	D5.T1.S1.P3	45.0	7.9	52.9
15.	Tax shield provided by interest expense	D5.T1.S1.P3	(48.0)	(0.4)	(48.4)
16.			(3.0)	7.5	4.5
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS	E5.T1.S1.P1	(106.4)	-	(106.4)
18.	Net deficiency -w/out CC/CIS	E5.T1.S1.P1	(78.2)	-	(78.2)
19.			28.2	-	28.2
20.	Sub-total Allowed Revenue		2,679.6	122.7	2,802.3
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	0.8	0.8
22.	**Allowed Revenue**		2,679.6	123.5	2,803.1
	Revenue at existing Rates				
23.	Gas sales	C5.T1.S1.P1	2,372.7	91.8	2,464.5
24.	Transportation service	C5.T1.S1.P1	198.7	18.4	217.1
25.	Transmission, compression and storage	C5.T1.S1.P1	1.8	-	1.8
26.	Rounding adjustment		-	-	-
27.	Total		2,573.2	110.2	2,683.4
28.	**Gross revenue deficiency**		(106.4)	(13.3)	(119.7)

ALLOWED REVENUE
(DEFICIENCY)/SUFFICIENCY
2017 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS ($Millions)	Col. 3 CC-CIS ($Millions)	Col. 4 EGD Total ($Millions)
	Cost of Capital				
1.	Rate base	B6.T1.S1.P1	5,716.9	19.7	5,736.6
2.	Required rate of return	E6.T1.S1.P1	7.04%	6.44%	7.04%
3.			402.5	1.3	403.8
	Cost of Service				
4.	Gas costs	D6.T1.S1.P1	1,632.5	-	1,632.5
5.	Operation and maintenance	D6.T1.S1.P1	346.1	104.4	450.5
6.	Depreciation and amortization	D6.T1.S1.P1	300.7	12.7	313.4
7.	Fixed financing costs	D6.T1.S1.P1	1.9	-	1.9
8.	Debt redemption premium amortization	D6.T1.S1.P1	-	-	-
9.	Company share of IR agreement tax savings	D6.T1.S1.P1	-	-	-
10.	Municipal and other taxes	D6.T1.S1.P1	47.9	-	47.9
11.			2,329.1	117.1	2,446.2
	Miscellaneous operating and non operating revenue				
12.	Other operating revenue	C6.T1.S1.P1	(41.2)	-	(41.2)
13.	Interest and property rental	C6.T1.S1.P1	0.0	-	-
14.	Other income	C6.T1.S1.P1	(0.1)	-	(0.1)
15.			(41.3)	-	(41.3)
	Income taxes on earnings				
16.	Excluding tax shield	D6.T1.S1.P3	51.3	7.5	58.8
17.	Tax shield provided by interest expense	D6.T1.S1.P3	(50.0)	(0.2)	(50.2)
18.			1.3	7.3	8.6
	Taxes on deficiency				
19.	Gross deficiency -w/out CC/CIS	E6.T1.S1.P1	(147.7)	-	(147.7)
20.	Net deficiency -w/out CC/CIS	E6.T1.S1.P1	(108.6)	-	(108.6)
21.			39.1	-	39.1
22.	Sub-total Allowed Revenue		2,730.7	125.7	2,856.4
23.	Customer Care Rate Smoothing Variance Account Adjustment		-	2.9	2.9
24.	**Allowed Revenue**		2,730.7	128.6	2,859.3
	Revenue at existing Rates				
25.	Gas sales	C6.T1.S1.P1	2,388.5	91.8	2,480.3
26.	Transportation service	C6.T1.S1.P1	192.7	18.4	211.1
27.	Transmission, compression and storage	C6.T1.S1.P1	1.8	-	1.8
28.	Rounding adjustment		-	-	-
29.	Total		2,583.0	110.2	2,693.2
30.	**Gross revenue deficiency**		(147.7)	(18.4)	(166.1)

Witness: K. Culbert

ALLOWED REVENUE
(DEFICIENCY)/SUFFICIENCY
2018 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base	B7.T1.S1.P1	5,899.1	7.0	5,906.1
2.	Required rate of return	E7.T1.S1.P1	7.11%	6.44%	7.11%
3.			419.4	0.5	419.9
	Cost of Service				
4.	Gas costs	D7.T1.S1.P1	1,632.5	-	1,632.5
5.	Operation and maintenance	D7.T1.S1.P1	353.3	108.5	461.8
6.	Depreciation and amortization	D7.T1.S1.P1	309.4	12.7	322.1
7.	Fixed financing costs	D7.T1.S1.P1	1.9	-	1.9
8.	Debt redemption premium amortization	D7.T1.S1.P1	-	-	-
9.	Company share of IR agreement tax savings	D7.T1.S1.P1	-	-	-
10.	Municipal and other taxes	D7.T1.S1.P1	50.4	-	50.4
11.			2,347.5	121.2	2,468.7
	Miscellaneous operating and non operating revenue				
12.	Other operating revenue	C7.T1.S1.P1	(41.2)	-	(41.2)
13.	Interest and property rental	C7.T1.S1.P1	0.0	-	-
14.	Other income	C7.T1.S1.P1	(0.1)	-	(0.1)
15.			(41.3)	-	(41.3)
	Income taxes on earnings				
16.	Excluding tax shield	D7.T1.S1.P3	60.7	7.2	67.9
17.	Tax shield provided by interest expense	D7.T1.S1.P3	(52.0)	(0.1)	(52.1)
18.			8.7	7.1	15.8
	Taxes on deficiency				
19.	Gross deficiency -w/out CC/CIS	E7.T1.S1.P1	(192.1)	-	(192.1)
20.	Net deficiency -w/out CC/CIS	E7.T1.S1.P1	(141.2)	-	(141.2)
21.			50.9	-	50.9
22.	Sub-total Allowed Revenue		2,785.2	128.8	2,914.0
23.	Customer Care Rate Smoothing Variance Account Adjustment		-	5.0	5.0
24.	**Allowed Revenue**		2,785.2	133.8	2,919.0
	Revenue at existing Rates				
25.	Gas sales	C7.T1.S1.P1	2,404.4	91.8	2,496.2
26.	Transportation service	C7.T1.S1.P1	186.6	18.4	205.0
27.	Transmission, compression and storage	C7.T1.S1.P1	1.8	-	1.8
28.	Rounding adjustment		0.3	-	0.3
29.	Total		2,593.1	110.2	2,703.3
30.	**Gross revenue deficiency**		(192.1)	(23.6)	(215.7)

Witness: K. Culbert