Attachment 29.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 50.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 51.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 52.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 54.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 54.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 74.1

REFER TO LIVE SPREADSHEET MODEL

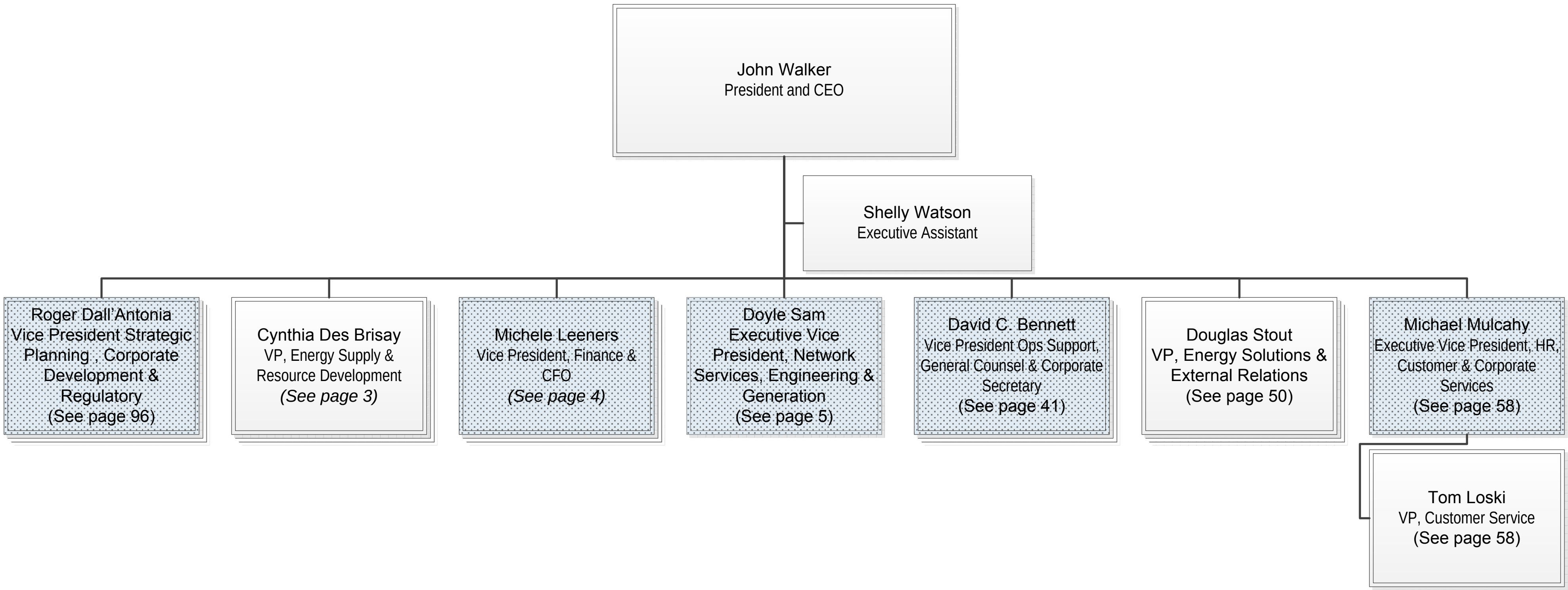
Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 75.1

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Cynthia Des Brisay** – VP, Energy Supply & Resource Development
  - **Cindy Baker** – Executive Assistant
  - **Joe Mazza** – Director, Resource Development
    - George Toring – *Gas Control & SCADA Manager* *(see page 3)*
    - Ron Zeilstra – Resource Development Manager
    - Michael Shoemaker – Strategic Policy Advisor
    - G.Arthur Kanzaki – Project Director
    - Kimberly Reibelt – Project Clerk
    - Atul Toky – Resource Development Manager
    - Edmond Leung – Manager, Resource Dev & Tech Assessment
      - Llewellyn Fonseca – Project Assessment Specialist
    - Rohit Pala – Resource Development Manager
  - **Michael Hopkins** – Senior Manager, Commodity & Price Risk
    - S.Nina Virdee – Compliance and Performance Analyst
    - Tony Liu – Price Risk Analyst
    - Hans Mertins – Manager, Commodity
      - Leo Hecher – M&E Relief
      - Mary Lang – Energy Supply Market Analyst
  - **Tania Specogna** – Sr Mgr, Midstream Development & Services
    - Bryan Lane – Midstream Services Manager
      - Christine Braun – Midstream Operations Manager
      - Stephanie Salbach – Transportation Services Manager
      - Jordan Cumming – Market Analyst Midstream
      - Colleen Wilson – Market Analyst, Midstream
  - **Brian Noel** – Manager, Business Planning & Performance
    - Richard Leong – Gas Supply Operations Analyst
    - Nives Chung – Financial Accounting Analyst
    - Kristine Carey – Gas Supply Operations Analyst
    - Anita Leung – Senior Rates Analyst
    - Mike Di Giovanni – Business Integration Manager
    - Hao Chen – Senior Rates Analyst
    - Douglas Richardson – Manager, Energy Supply
      - Darlene Pigura – Contract & Finance Coordinator

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

George Toring
Gas Control & SCADA Manager

- William Wong – Technologist 3 - SCADA
- John Luu – Technologist 4 - SCADA
- Darrell Sommer – Gas Control Coordinator
- Michael Osachuk – Gas Controller
- Torrence Schlitt – Gas Controller
- Keith McMillan – Gas Controller
- Lance Field – Gas Controller
- Ron Kong – Gas Controller
- Soroush Mansouri – Gas Controller
- Todd Gilchrist – Gas Controller

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- Michele Leeners, Vice President, Finance & CFO
  - Chuck Lee, Director Financial Operations
    - Flossy Nazareth, Financial Process & Support Manager
      - Ruby Hayat, Financial Accounting Clerk 3
      - Janice Reid, Accounts Payable Clerk 2
      - Carlo Vizza, Accounts Payable System Support Analyst
      - Darren Reibelt, Accounts Payable Clerk 2
      - Rosie Penner, Accounts Payable Leader
      - Lalaine Mueda, Credit Card Program Administrator
      - Monique Ramlu, Accounts Payable Support Clerk
      - Sheri Taylor-Bullen, Credit Card Program Administrator
      - Melissa Irvine, Accounts Payable Support Clerk
      - Sarah Hirang, Accounts Payable Clerk 2
      - Krista Owen, Accounts Payable Clerk 2
  - James Wong, Director, Finance & Planning
    - Peter Nasmyth, Manager, Financial Planning & Control
      - Elisa Zaporteza, Operations Finance Manager
        - Amina Esmail, Operations Financial Analyst
        - Caroline Gill, Operations Financial Coordinator
        - Emmanuel Bondoc, Operations Financial Analyst
        - Lorel Cop, Operations Financial Coordinator
        - Simar Johal, Operations Financial Analyst
        - Sharon McGregor, Operations Financial Analyst
        - Mary Tai, Operations Financial Analyst
      - Tom Burbridge, Financial Planning Manager
        - Simon Ho, Senior Regulatory Work Leader
        - Dan Lum, Financial Accounting/Credit Analyst
      - (Kellie) Wei Ting Chu, CMO Manager
        - Roland Klaussner, Operations Financial Coordinator
  - Peter Orr, Director, Financial Planning (See page 98)
  - Sreekanta Banerjee, Manager, Budgets and Forecasting
    - Tat Tang, Asset & Operations Reporting Manager
      - Lilyana Tabakova, Asset Accounting Manager
        - Kathy Harbison, Asset Accounting Analyst 2
        - Silvia Agudelo, Asset Accounting Analyst 2
        - Giancarlo Cosico, Asset Accounting Analyst 2

NOT a FEI employee (shaded boxes: Michele Leeners, Chuck Lee, Peter Orr, Sreekanta Banerjee)

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Doyle Sam** – Executive Vice President, Network Services, Engineering & Generation
  - **Marina Mowbray** – Executive Assistant
  - **Dana Johnston** – Project Director,Infrastructure Prog Dev
  - **Ferenc Pataki** – Director, Operations - Metro Van/Ops Ctr
    - **Mark Fabbro** – Regional Manager, Metro Vancouver *(See page 6)*
    - **Brent MacPherson** – Director, Operations Centre (See page 7)
  - **Rolf Lyster** – Director, Gas Plant Operations & PMO
    - **Jaime Chiang** – Senior Manager, Plant Operations (See page 8)
    - **Pierre Dufour** – Manager Project Management Office (See page 14)
  - **Barry Smithson** – Director Operations
    - **Christopher Hyland** – Regional Manager, Interior South (See page 15)
    - **Mike MacDonald** – Supervisor Vegetation Management
      - **Ron Schafer** – Quality & Compliance Manager
  - **Randall Kieper** – Manager, Business Performance - Dist Ops
    - **Greg Elenko** – Manager, Compliance & Competency (See page 23)
    - **Calvin Bergenstein** – Manager, Operations Services (See page 24)
    - **Janice Robertson** – Operations Reporting Manager (See page 25)
  - **Paul Chernikhowsky** – Director Engineering Services
    - **Janet Green** – Manager, Gas System Assets (See page 26)
    - **Bryan Balmer** – Manager, System Integrity Programs (See page 27)
    - **Andrew Loge** – Manager, Engineering (See page 28)
    - **John Himmel** – Manager, Geographic Information Systems (See page 29)
  - **Donald Wallace** – Director, Operations - FEVI/FV/Inter N.
    - **Ian Miki** – Regional Manager Dist - Fraser Valley (See page 32)
    - **Brian Neary** – Regional Manager, FEVI
    - **Kevin Gerow** – Regional Manager, Interior North (See page 33)

NOT a FEI employee (shaded boxes: Doyle Sam, Barry Smithson, Paul Chernikhowsky, Pierre Dufour, Mike MacDonald)

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Mark Fabbro
Regional Manager, Metro Vancouver

Michael Orth — Operations Manager, Pressure Control

- Wayne Shave — Customer Service Technician 1
- Cyrus Emmanuel — Commercial Customer Service Technician
- Ivan Jensen — Commercial Customer Service Technician
- Gary Bradbury — Distribution Service Agent
- Bryan Miki — Commercial Customer Service Technician
- Francesco Perozzo — Commercial Customer Service Technician
- Carlos Alves — Pressure & Measurement Technician
- Kelly Simmons — Commercial Customer Service Technician
- Craig Murphy — Customer Service Technician 1
- Stephen Meers — Commercial Customer Service Technician
- Joseph Raicovi — Pressure & Measurement Technician
- Trevor Day — Customer Service Technician 1
- Stewart King — Commercial Customer Service Technician

Charles Vanditmars — Operations Manager, Metro

- Ryan Osborne — Customer Service Technician 1
- Greg Smith — Customer Service Technician 1
- Brian Hirose — Crew Leader
- Casey Anderson — Customer Service Technician 2
- Alfred Hansen — Distribution Mechanic
- Robert Richards — Crew Leader
- Michael Sayer — Customer Service Technician 1
- Gregory Snydal — Distribution Mechanic
- Dexter Contaoi — Customer Service Technician 1
- Dominic Beaty — Distribution Mechanic
- Alex Del Bianco — Distribution Mechanic
- Sean O'Flynn — Distribution Apprentice
- Andrew Millar — Equipment Operator/ Distribution Mechanic
- Mike Klimek — Distribution Mechanic
- Cory Simpson — Customer Service Technician 1
- Brad St. George — Customer Service Technician 1
- Blair McGarvey — Customer Service Technician 1
- Stefan Wong — Customer Service Technician 2
- Roberto Vero — Customer Service Technician 1

Roger Velo — Operations Manager, Metro

- Bryan Abel — Customer Service Technician 1
- Mark Norris — Customer Service Technician 1
- S.Mark Richardson — Distribution Mechanic
- Jeremy Scramstad — Distribution Apprentice 2013Q2
- Keith Martinson — Crew Leader
- Venters Oraas — Crew Leader
- Russ Roberts — Customer Service Technician 1
- Randolph Bell — Equipment Operator 1
- Brandon Baker — Distribution Mechanic
- Ryan Boivin — Distribution Mechanic
- William Currie — Distribution Service Agent
- Braden Roy — Distribution Apprentice 2013Q2
- Damian McCloskey — Customer Service Technician 1
- Ian Finch — Distribution Mechanic
- Ole Hensrud — Distribution Mechanic
- Michael Lutsiak — Crew Leader
- Robert Favaro — Customer Service Technician 1
- Mike Catton — Distribution Apprentice
- Graham Webster — Equipment Operator/ Distribution Mechanic
- Dale Gauthier — Customer Service Technician 1
- Aaron Cuming — Distribution Apprentice 2013Q2
- Chris Baker — Customer Service Technician 1
- Jared Kennedy — Distribution Mechanic
- Guy Belair — Customer Service Technician 1

John Trochta — Operations Manager, Metro

- Peter Merola — Customer Service Technician 1
- Brad McHugh — Distribution Mechanic
- Wes Shannon — Distribution Mechanic
- Chad Williams — Distribution Apprentice 2013Q2
- Michael Bloxham — Crew Leader
- Shaun Trevor Hardychuk — Customer Service Technician 1
- Jeromy Krasniski — Distribution Apprentice 2013Q2
- Edward Gagnon — Leak Survey Technician 1
- Gregory Burdett — Customer Service Technician 2
- Catriona Hardie — Customer Service Technician 1
- Anderson Hsieh — Distribution Apprentice 2013Q2
- Douglas Weninger — Customer Service Technician 1
- Ryan Tinline — Distribution Mechanic
- William Ralston — Equipment Operator 1
- Antony Balantes — Customer Service Technician 1
- Sheldon Van Schagen — Customer Service Technician 1
- Dante Lanzi — Crew Leader
- Peter Barton — Distribution Service Agent
- John Guzzo — Crew Leader
- Daniel Golding — Distribution Mechanic
- Travis McGibbon — Distribution Apprentice
- Clinton Carey — Distribution Mechanic

Jason Jarvis — Operations Manager, Metro

- Kamaljit (Kamal) Sidhu — Customer Service Technician 1
- Chris Stewart — Customer Service Technician 1
- Gary Gosal — Crew Leader
- Paul Solly — Crew Leader
- Aryan Johal — Customer Service Technician 2
- Trevor Moore — Customer Service Technician 1
- Joel McNeney — Customer Service Technician 1
- Valeriy Zhevelyuk — Customer Service Technician 1
- Peter Kaszonyi — Customer Service Technician 2
- Ross Galte — Customer Service Technician 1
- Kevin McNeney — Customer Service Technician 1
- Denny Sudiro — Customer Service Technician 1
- Salvatore Randazzo — Distribution Mechanic
- Gregory Swan — Distribution Service Agent
- Daniel Mucci — Distribution Mechanic
- Colin Quince — Equipment Operator/ Distribution Mechanic

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Brent MacPherson
Director, Operations Centre

Janet Steinmann
Business Support Manager

Elena Kau
Special Assignment Manager

Lee Beran
Pre-requisite and Closing Manager
(See page 9)

Trevor Kereliuk
Special Assignment Manager

Lisa Elliott
M&E Relief
(See page 99)

Michael Killacky
Manager, Install Centre
(See page 11)

Lisa LaRocque
Process Manager

Matthew Yasinchuk
Dispatch Manager
(See page 12)

Alan North
Manager, Planning & Design
(See Page 97)

Winnie Hsu
Emergency Support Manager
(See page 13)

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Jaime Chiang** – Senior Manager, Plant Operations
  - **Barry Kleven** – Compression & Controls Tech Group Leader
    - Troyce Beglaw – Compression & Controls Technician 1
    - Mark Cerina – Compression & Controls Technician 1
    - Ryan McEwen – Compression & Controls Technician 1
    - Nelson Cobra – Compression & Controls Technician 1
    - Dave Kalf – Compression & Controls Technician 1
    - Gary Grisewood – Millwright
    - Adriana Macasso – Admin Assistant, Transmission Ops
    - Greg Negrey – Compression & Controls Technician 1
    - Edward Rilkoff – Compression & Controls Technician 1
    - Lorne Graham – Compression & Controls Technician 1
    - Stuart Bolland – Compression & Controls Technician 1
  - **James Cox** – Operations Manager, Tilbury LNG
    - Michael Bildstein – LNG Plant Operator 1
    - John Kenny – LNG Plant Operator 2
    - Ken Hardinge-Rooney – LNG Plant Operator 1
    - Douglas Funk – LNG Plant Operator 1
    - Darryl Louie – Technologist 4 - LNG Plant
    - Veronica Burdeny – Admin Assistant, Transmission Ops
    - T.Craig Robertson – LNG Plant Operator 1
    - Mark Kobetitch – LNG Plant Operator 1
    - A. John Vojtko – LNG Plant Operator 1
    - Oliver McNeill – LNG Plant Operator 1
    - Amrik Ghuman – LNG Plant Operator 2
    - Harjinder Samra – LNG Plant Operator 1

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Lee Beran** – Pre-requisite and Closing Manager
  - Joanne Bliss – Operations Support Representative 2
  - Brad Dixon – Operations Support Representative 2
  - Chelsea Knowles – Operations Support Representative 2
  - Eva Ross – Operations Support Representative 3
  - Sonia Leugner – Operations Support Representative 3
  - Beryl Misquith – Operations Support Representative 2
  - Deanna Mackwell – Operations Support Representative 3
  - Anuradha Bhasin Chaudary – Operations Support Representative 2
  - Aida Macapinlac – Operations Support Representative 3
  - Alison Petrie – Operations Support Representative 3
  - Laurie Henry – Operations Support Representative 3
  - Rowena Pineda – Operations Support Representative 3
  - Breanna Fabbro – Operations Support Representative 2
  - Nicky Johnson – Operations Support Representative 3
  - Lindsey Bartlett – Operations Support Representative 3
  - Jayne Barth – Operations Support Representative 3
  - Rowena Fortaleza – Operations Support Representative 3
  - Charmaine Ross – Operations Support Representative 3
  - Karen Robertson – Operations Support Representative 3
  - Elizabeth Beck – Operations Support Rep Workleader
  - Fran Dillen – Operations Support Rep Workleader
  - Angela Vickers – Operations Support Representative 2
  - Andrea Gross – Operations Support Representative 2
  - Debbie Kazakoff – Operations Support Representative 3
  - Niki Kenny – Operations Support Representative 3
  - Kim Mairs – Operations Support Representative 2
  - S.Dianne Goldsmith – Operations Support Representative 2
  - Joni Strand – Operations Support Representative 3
  - Alex Chow – Operations Support Representative 3

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Cynthia Peden
Resource Planning Manager

- Sam Hsu — Relief Clerk
- Shirley McDonald — Dispatcher
- Jessica Lindsay — Operations Support Representative 2
- Vicki McArthur — Dispatcher
- Gina Jacinto — Operations Support Representative 3
- Maria Jones — Operations Support Representative 3
- Courtney Burt — Relief Clerk
- Sheenah Demsey — Dispatcher
- Jo-Anne Bullock — Operations Support Representative 2
- Jill Cooper — Resource Management Co-ordinator
- Christine Needham — Operations Support Representative 2
- Stefanie MacGillivray — Operations Support Representative 3
- Nicole Elliott — Operations Support Representative 3
- Carol-Ann Matthews — Dispatcher
- Karen Fisher — Dispatcher
- Manuela Sarunic — Dispatcher
- Crystal Spring — Dispatcher
- Liza Santiago — Operations Support Representative 3
- Sharron McMillan — Operations Support Representative 3
- Jessica Elliott — Operations Support Representative 3
- Cori Forster — Dispatcher
- Maureen Belton — Resource Management Co-ordinator
- Rosanne Scott — Operations Support Representative 3
- Maria Ziegler — Dispatcher
- Darlene Stowe — Operations Support Representative 3
- Patricia Tasker — Dispatcher
- Rhona Yen — Operations Support Representative 2
- Janet Bronson — Operations Support Representative 3
- Rubeena Mokha — Operations Support Representative 3
- Julie Russo — Operations Support Representative 2
- Dalvir Kahlon — Operations Support Representative 2
- Colleen Ferguson — Resource Management Co-ordinator
- Beth Ulriksen — Operations Support Representative 3
- Rocelle Tiu — Dispatcher
- Colleen McKeating — Operations Support Representative 3
- Janice McDonald — Resource Management Co-ordinator
- Karen Fantillo — Resource Management Co-ordinator
- Taryn Ohs — Operations Support Representative 3
- Carmel Klassen — Dispatcher

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Michael Killacky
Manager, Install Centre

- Kelly Forshner — Operations Support Representative 2
- Carol Ross — Operations Support Representative 3
- Bill Padda — Planning & Design Workleader
- Ronil Perera — Planning & Design Technologist 2
- Vyacheslav Katalevskiy — Planning & Design Technologist 2
- Neil Hourihane — Planning & Design Workleader
- Robin Northey — Operations Support Representative 3
- Jane Whitehead — Operations Support Representative 3
- Sean Reynolds — Planning & Design Technologist 2
- Michelle Simister — Planning & Design Technologist 2
- Tammy Hubbard — Operations Support Representative 3
- Sarah Glass — Summer Student
- Barry Best — Planning & Design Technologist 2
- Mark Sampson — Planning & Design Technologist 2
- Brenda Robertson — Planning & Design Workleader
- Lisa Meers — Operations Support Representative WL
- Brad Freeman — Planning & Design Technician
- Holly Motherwell — Planning & Design Technologist 2
- Rory Guicheteau — Planning & Design Technologist 2
- Candice Walker — Operations Support Representative 2
- John Stone — Planning & Design Technologist 2
- Glenda Decock — Operations Support Representative 3

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Matthew Yasinchuk
Dispatch Manager

- Nancy Motherwell — Planning & Design Technician
- Gina Nash — Planning & Design Technologist 1
- Kingsley Rodriguez — Planning & Design Technician
- Phyllis De Ford — Planning & Design Technician
- Julie Grates — Operations Support Representative 3
- Yvette D'Andrea — T & D Surveyor 2
- Hazel Cosico — Planning & Design Technologist 1
- Surinder Johal — Planning & Design Technician
- Jeffray Dela Cruz — Planning & Design Technologist 2
- Gwen Stepanick — Planning & Design Technologist 1
- Greg Hill — Planning & Design Technologist 2
- Louie Foronda — Planning & Design Technologist 2
- Atousa Ahmadi Naeini — Planning & Design Technician
- Elson Canceran — Planning & Design Technologist 2
- Ryan Duggan — Planning & Design Technologist 1
- Ling Hu — Planning & Design Workleader
- Terence Crites — Planning & Design Technologist 2
- Erin Chan — Planning & Design Technologist 1
- Frank Majcenovic — T & D Surveyor 2
- Adam Kirby — Planning & Design Workleader
- Heiber Mina — T & D Surveyor 2
- Elaine Teesdale — Planning & Design Technologist 2
- Tom Der — Planning & Design Technologist 2
- James Lee — Planning & Design Technician
- Nicki Martin — Planning & Design Technician
- Patti Cafe — Planning & Design Technician
- Kathryn Shankie — Planning & Design Technician
- Carol Henney — Planning & Design Technician
- Tracy Yik — Planning & Design Technologist 1
- Lyle Beck — Planning & Design Technician
- Shannon Zander — Operations Support Representative 3
- Patricia Nitsch — Planning & Design Workleader
- Joe Nex — Planning & Design Technologist 1
- Karen Barfoot — Planning & Design Technologist 2
- Corliss Lang — Planning & Design Technician
- Gordon Spelay — Planning & Design Technician
- Aurora Palad — Planning & Design Technician
- Andy Hsu — Planning & Design Technician

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Winnie Hsu
Emergency Support Manager

- **Baljinder Grewal** – Emergency & Operations Representative
- **Sandra Hilderman** – Emergency & Operations Representative
- **Sherry Dhillon** – Emergency & Operations Representative
- **Zulfy Lateef** – Emergency & Operations Representative
- **Amarjit (Amy) Hayre** – Emergency & Operations Representative
- **Nicole Strang-Lentz** – Emergency & Operations Representative
- **Roseleen Nand-Lal** – Emergency & Operations Representative
- **Duangkamol (Alex) Paibool** – Emergency & Operations Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Pierre Dufour** – Manager Project Management Office
  - **Neil Bolger** – Sr Engineering Project Mgr Lower Mnld
    - Nik Ong – Engineering Project Manager
    - Melanie Kilpatrick – Engineering Project Manager
    - Frank Lee – Project Manager
  - **Paul Tassie** – Senior Project Manager
    - Mike Walls – Project Manager
    - John Quinn – Senior Project Manager
    - Kevin Tomm – Project Manager
    - Tony Pham – Project Manager
    - K. Glen Hurley – Project Manager
  - **Debora Warren** – Senior Engineering Project Mgr VI & LNG
    - Firat Nalbantoglu – Senior Engineering Project Manager
    - Larry Steinmann – Senior Project Manager
    - Eric Larson – Senior Project Manager
  - **Gordon Swan** – PMO Business Manager
    - Stacie Susheski – Project Contracts Work Leader
    - Robert Booth – Senior Engineering Project Manager
    - Barry Sampson – Construction Contracts Manager
    - Althea Usherwood – Project Management Administrative Assist
    - Lorraine Holman – Project Contracts Administrator
    - Laurie Hood – Project Contracts Administrator
    - Attila Szamoskozi – Project Contracts Administrator

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Christopher Hyland
Regional Manager, Interior South

- **Mark Morrison** – Operations Manager, Interior South (See page 16)
- **Kenneth Valuck** – Operations Manager, Interior South (See page 17)
- **Gary Fillingham** – Operations Manager, Interior South (See page 18)
- **Paul Kropp** – Operations Manager, Pipeline (See page 19)
- **Clifford Wylie** – Operations Manager, Interior South (See page 20)
- **David Tookey** – Operations Manager, Interior South (See page 21)
- **Daniel Hale** – Manager, Operations Services
- **Stephen Breer** – Operations Manager, Interior South (See page 22)

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Mark Morrison** — Operations Manager, Interior South
  - Trina Davis — Field Operations Assistant
  - Gerry Harmon — Pressure & Measurement Apprentice
  - Gordon Strang — Customer Service Technician 1
  - Gene Deering — Crew Leader
  - Brian Prodaniuk — Sr Sales & Service Technician
  - Scott Reynolds — Planning & Design Technologist 2
  - Mike Makway — Distribution Apprentice
  - Marnie Audia — Field Operations Assistant
  - Grant McLean — Equipment Operator/Distribution Mechanic
  - Mark Goupil — Equipment Operator/Distribution Mechanic
  - Larry Jamieson — Customer Service Technician 1
  - Donald Urbanoski — Customer Service Technician 1
  - W. Paul Keelan — Customer Service Technician 1
  - Steven Baher — Welder 1 (Crew Leader Arc)
  - Trevor Balyk — Pressure & Measurement Apprentice
  - John Cullen — Distribution Service Agent

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Kenneth Valuck
Operations Manager, Interior South

- **Chad Braybrook** – Planning & Design Technologist 2
- **Ben Proskiw** – Planning & Design Technologist 2
- **Terry Pell** – Crew Leader
- **Gordon Smith** – Equipment Operator/Distribution Mechanic
- **Michael Murdoch** – Welder 1 (Crew Leader Arc)
- **Ian Van Steinburg** – Equipment Operator/Distribution Mechanic
- **Rob Cadden** – Welder 1 (Crew Leader Arc)
- **Gary Rahier** – Planning & Design Technologist 2
- **Darryl Sarin** – Distribution Service Agent
- **Curtis Griffin** – Equipment Operator/Distribution Mechanic
- **Jeff Giebelhaus** – Distribution Mechanic

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Gary Fillingham
Operations Manager, Interior South

- **Gavin McGregor** — Customer Service Technician 1
- **Derek Ekren** — Distribution Mechanic
- **Cherie Verkerk** — Field Operations Assistant
- **Chris Villeneuve** — Customer Service Technician 1
- **Brad McDonald** — Customer Service Technician 1
- **Peter Lesik** — Welder 1 (Crew Leader Arc)
- **Larry Lorentsen** — Planning & Design Technologist 2
- **Roland Georgetti** — Equipment Operator/Distribution Mechanic
- **Doug Aeichele** — Distribution Mechanic
- **Randy Borton** — Crew Leader
- **Shane Whitley** — Distribution Mechanic
- **Darrell Rahier** — Distribution Service Agent
- **Reginald Neufeld** — Commercial Customer Service Technician
- **Maurice Poirier** — Equipment Operator/Distribution Mechanic
- **Douglas Wiffen** — Customer Service Technician 1

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Paul Kropp
Operations Manager, Pipeline

- **Randall Loski** – Pipeline Technician 1
- **Vincent Senger** – Pipeline Technician 1
- **Geoffrey Kirkpatrick** – Pipeline Technician/Welder
- **Dustin Rhinas** – Pipeline Technician 2
- **James Wiebe** – Pipeline Technician/Equipment Operator
- **Elouise Brissette** – Admin Assistant, Transmission Ops
- **Brett Allan Carlson** – Pipeline Technician 2
- **Greg Yaretz** – Pipeline & Right of Way Inspector
- **Douglas Roller** – Pipeline Technician 2
- **Bradley Braybrook** – Pipeline & Right of Way Inspector
- **William Shostak** – Pipeline Technician 1

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Clifford Wylie
Operations Manager, Interior South

- **Frederick Wittman** — Customer Service Technician 1
- **Scott Lega** — Distribution Apprentice
- **Robert Castle** — Customer Service Technician 1
- **Mike Stefanik** — Welder 1 (Crew Leader Arc)
- **Scott Cameron** — Distribution Mechanic
- **Joanne Osachoff** — Field Operations Assistant
- **Kimbal Becker** — Customer Service Technician 1
- **William Rogers** — Pressure, Measurement & Controls Tech
- **Glen Bock** — Distribution Mechanic
- **David Gibson** — Welder 1 (Crew Leader Arc)
- **Randy Ogren** — Planning & Design Technologist 2
- **Kenneth Whitnack** — Distribution Service Agent
- **Christopher Welch** — Customer Service Technician 1
- **Brad Rae** — Customer Service Technician 1
- **Brent Gombar** — Commercial Customer Service Technician

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

David Tookey
Operations Manager, Interior South

- **Dennis McElroy** — Customer Service Technician 1
- **Andrew Watson** — Customer Service Technician 1
- **Shelley Tennison** — Field Operations Assistant
- **Brandon Weel** — Customer Service Technician 2
- **Douglas Avigdor** — Pressure & Measurement Apprentice
- **Tom Baranyi** — Customer Service Technician 1
- **Carmen Gammon** — Field Operations Assistant
- **Andrew MacKay** — Customer Service Technician 1
- **Neil Gatti** — Customer Service Technician 1
- **Mike Razzano** — Customer Service Technician 1
- **Jason Dingwall** — Customer Service Technician 1
- **Jared Hyland** — Customer Service Technician 1
- **Kerry Leary** — Pressure & Measurement Apprentice
- **Brad Conlin** — Commercial Customer Service Technician
- **Garland Wyatt** — Distribution Service Agent

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

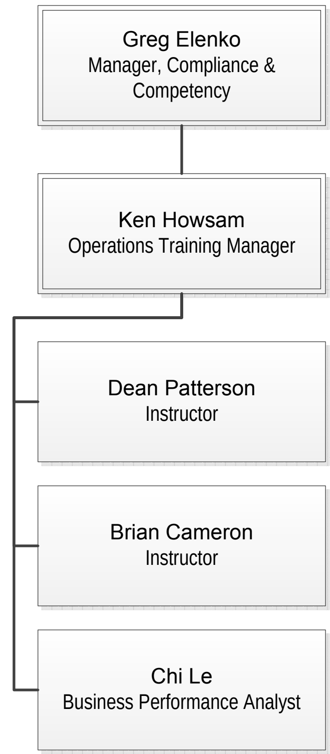
As at June 30, 2013

- **Stephen Breer** — Operations Manager, Interior South
  - Benjamin Johnson — Pressure & Measurement Apprentice
  - Brian Messer — Planning & Design Technologist 2
  - Adrian Alva — Crew Leader
  - Bruce Koski — Customer Service Technician 1
  - Paul Morton — Customer Service Technician 1
  - Dave Lauer — Equipment Operator/Distribution Mechanic
  - Gary Fergusson — Customer Service Technician 1
  - Diana Kelly — Field Operations Assistant
  - Geoffrey Gawne — Distribution Service Agent
  - Graham Dorrell — Distribution Mechanic
  - Bruce Carnegie — Customer Service Technician 1
  - Timothy Gould — Customer Service Technician 1
  - Alan Hunter — Welder 1 (Crew Leader Arc)

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

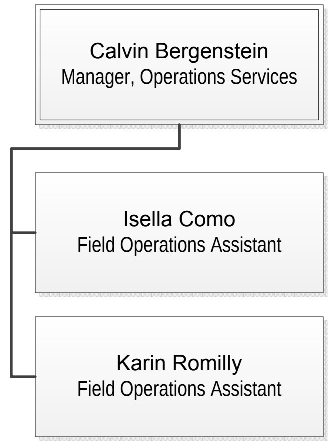
As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

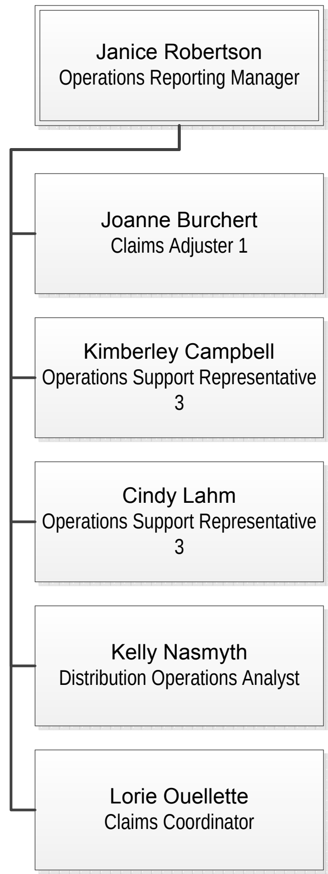
As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

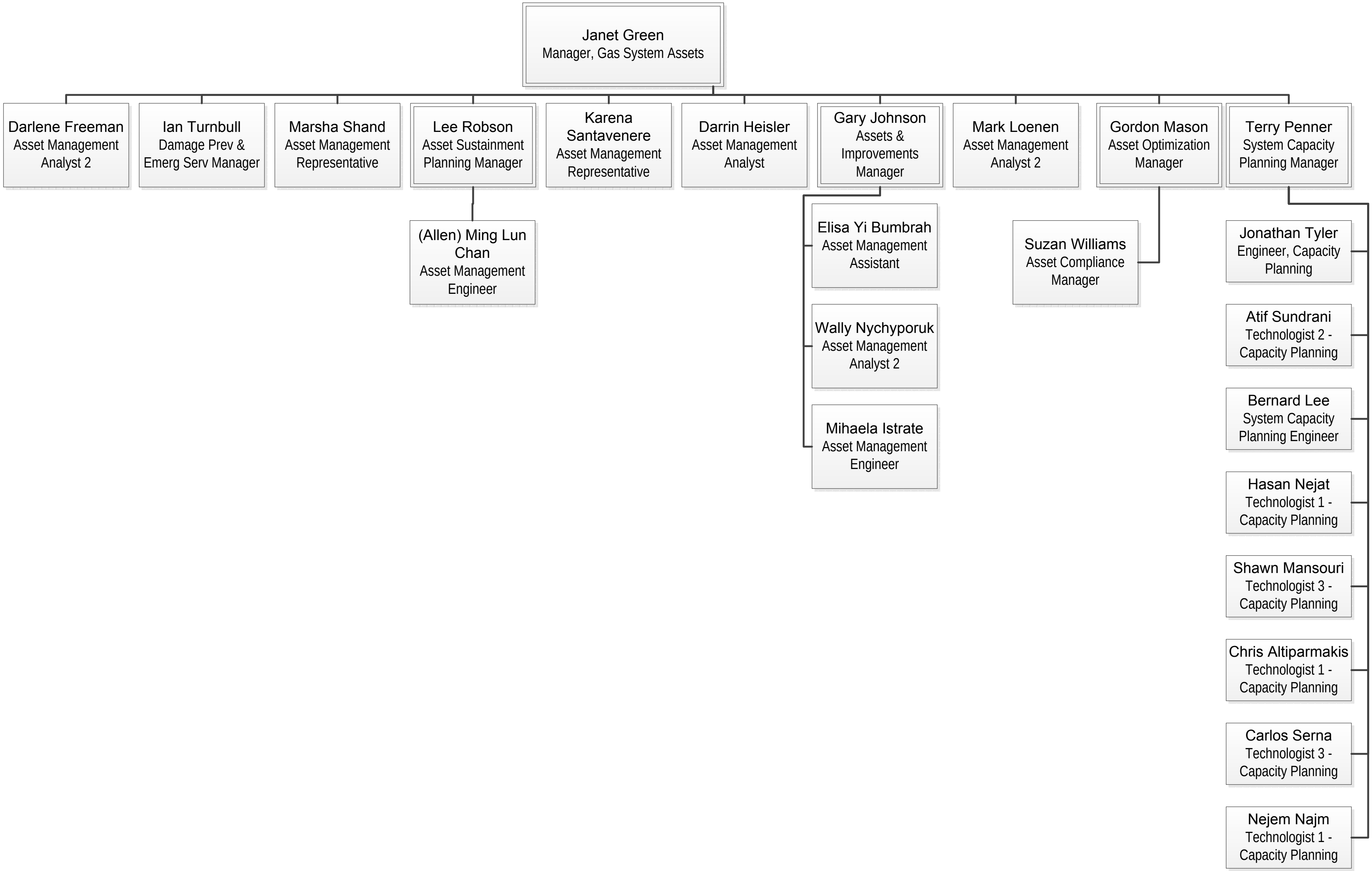
As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Bryan Balmer** — Manager, System Integrity Programs
  - **Taylor Campbell** — Systems Integrity Programs Eng Co-op
  - **Jim Lindberg** — Integrity/Corrosion Control Analyst 1
  - **Keith Recsky** — Senior Engineer, Integrity
  - **Kevin Siggers** — Integrity Engineer
  - **Christopher Billinton** — Senior Engineer Specialist, Integrity
  - **Scott Bowing** — Corrosion Control Manager (See page 30)
  - **Ian Thornton** — Integrity/Corrosion Control Analyst 1
  - **Frank Mostad** — Integrity/Corrosion Control Analyst 1
  - **Md Mujibur Rahman** — Senior Engineer, Geotechnical
  - **Michael Salamon** — Senior Engineer, Integrity
  - **Cameron Stuart** — Data Clerk
  - **Bassam Saad** — Senior Engineer, Geotechnical

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Andrew Loge
Manager, Engineering

- Roger Vino — M&E Relief
- Franjo Sedlar — Engineering Drafting Work Leader
- Paul Tang — Senior Engineer Specialist
- Kenley Ng — Engineer
- Andrew Doyle — Junior Engineer
- Mandan Vahabzadeh Memari — Engineering Co-op Student
- Kelly Bryck — Gas Lab Co-op
- Andrzej Maj — Project Engineer
- James Davison — Engineering Co-op Student
- Evan Dacey — Junior Engineer
- Kurtis Newman — Engineering Co-op Student
- Sameh Fahmy — Engineering Drafter 2
- Dave Nicolson — Plant Engineer
- Johnny Wu — Junior Engineer
- Andre Herath — Junior Engineer
- Elizabeth Chatwood — Engineering Drafter 3
- Mark Buckley — Technologist 3 - Measurement
- Andrew Gibson — LNG Plant Engineer
- Nina Draganov — Technologist 3 - Pipeline Design/ Drafter
- Cheuk Yin Wong — Junior Engineer
- Walter Osaduik — Technologist 4 - Instrumentation Design
- Tony Chen — Junior Engineer
- Maureen LaHaise — Administrative Assistant, Engineering
- Christopher Wilcock — Laboratory Technologist
- Danielle Gillanders — Junior Engineer
- Tat Fung (Vincent) Tam — Engineering Drafter 3
- Peter Ling — Engineer
- Joyce Kwok — Engineering Drafter 2
- Timothy Bouzovetsky — Engineering Drafter 3
- Konstantinos Imertziadis — Technologist 4 - Electrical Design
- Nickolas Bilouzenko — Technologist 4 - Electrical Design
- Barry Feng — Technologist 4 - Instrumentation Design
- Austin Tsai — Engineering Co-op Student
- Niko Boskovic — Engineering Supervisor – Stations (See page 31)
- David Pan — Engineering Co-op Student
- Frank Devine — Engineering Drafter 3
- Kyung Chan Min — Junior Engineer

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

John Himmel
Manager, Geographic Information Systems

- **Cindy Harris** – Operations Support Representative 2
- **Bryan Sawers** – GIS Drafter 1
- **Peter Rauscher** – GIS Drafter 2
- **Lay Santiago** – GIS Drafter 1
- **Edward Norcott** – Technologist 3 - Geographic Info Systems
- **Keith Merritt** – GIS Drafter 1
- **Laura Del Bianco** – GIS Drafter 1
- **Kathleen Paul** – Operations Support Representative 2
- **Janice Ceron** – Engineering Clerk
- **Lovejoy Nazareth** – Manager, Projects – Geospatial (See page 34)
- **Ivana Smolcic** – GIS Drafter 1
- **Oscar Hung-Ju Huang** – Technologist 3 - Geographic Info Systems
- **Alan Ng** – GIS Drafter 3
- **Mary (Dong Mei) Lu** – GIS Drafter 2
- **Denise Sukic** – Engineering Clerk
- **Wickfield Chin** – Workleader, GIS
- **Gerald Meaden** – Technologist 3 - Geographic Info Systems
- **Jimmy Yip** – Data Integrity Manager (See Page 35)
- **Donna Salahub** – Senior Engineer
- **Ray Urner** – QA/QC Technician
- **Piet Nooij** – Production Process Manager
- **Jonathan Malko** – GIS Drafter 3
- **Kevin So** – GIS Drafter 1
- **Thomas Burt** – Workleader, GIS
- **Charlene Falcos** – GIS Drafter 2
- **Tom Katinic** – GIS Drafter 1
- **Shawn Bryden** – QA/QC Technician
- **Anna Villaruz** – GIS Drafter 3
- **Joshua Cioci** – GIS Drafter 1

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Scott Bowing** — Corrosion Control Manager
  - Sean Burns — Technician 1 - Corrosion Control
  - Ken Wall — Technician 4 - Corrosion Control
  - Duncan Reitz — Technician 3 - Corrosion Control
  - Robert North — Workleader - Corrosion Control
  - Darren Wiens — Technician 3 - Corrosion Control
  - Shane Zannella — Technician 1 - Corrosion Control
  - Stephen Fenning — Workleader - Corrosion Control
  - Ryan Smith — Corrosion Assistant
  - Tyler Mann — Technician 3 - Corrosion Control
  - Astri Langford — Technician 1 - Corrosion Control
  - David Barsukoff — Corrosion Assistant
  - Robert Lego — Technician 1 - Corrosion Control
  - Jeremy Hartley — Workleader - Corrosion Control
  - Don Burns — Technician 1 - Corrosion Control

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Niko Boskovic
Engineering Supervisor – Stations

- Magdi Kaldas
  Technologist 3 - Plant Design/Drafter
- Rehan Shahab
  Project Engineer
- Joseph (Simon) Cantin
  Engineering Drafter 3
- Randall Gomez
  Technologist 3 - Plant Design/Drafter
- Valerie McQuatt
  Technologist 3 - Plant Design/Drafter

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Ian Miki**
  Regional Manager Dist - Fraser Valley
  - **Lloyd Lamont**
    Operations Manager, Fraser Valley
    (See page 36)
  - **Terry Takashima**
    Operations Manager, Fraser Valley
    (See page 37)
  - **Yves Landry**
    Damage Prevention Manager
    - **Steven Marsden**
      Pipeline & Right of Way Inspector
    - **Robert Farrell**
      Pipeline & Right of Way Inspector
    - **Brian Beda**
      Pipeline & Right of Way Inspector
    - **Rob MacLeod**
      Pipeline & Right of Way Inspector
  - **Kenneth Kind**
    Operations Manager, Fraser Valley
    (See page 38)
  - **Gianni Del Bianco**
    Operations Manager, Pipeline
    (See page 39)
  - **Terry Zazula**
    Operations Manager, Fraser Valley
    (See page 40)

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Kevin Gerow** – Regional Manager, Interior North
  - **Francis Flack** – Operations Manager, Interior North
    - Jack Nohr – Welder 1 (Crew Leader Arc)
    - Jeff Moleski – Distribution Mechanic
    - Melvin Orr – Distribution Apprentice
    - Brent Foot – Distribution Mechanic
    - Robert Slavik – Distribution Apprentice 2013Q2
    - Andrew Bergestad – Distribution Apprentice 2013Q2
    - Michael Bast – Planning & Design Technologist 2
    - Greg Babcock – Planning & Design Technologist 2
    - Richard Harders – Welder 1 (Crew Leader Arc)
    - Brian Foot – Distribution Mechanic
    - Brian Deevy – Distribution Service Agent
  - **Norman Birkenhead** – Operations Manager, Interior North
    - James Stutt – Distribution Mechanic
    - Brian Valana – Planning & Design Technologist 2
    - Steve Calladine – Distribution Mechanic
    - Russel Konrad – Customer Service Technician 1
    - John Bibby – Customer Service Technician 1
    - Bryce Demoline – Distribution Mechanic
    - Robert Poole – Welder 1 (Crew Leader Arc)
    - Ed Everett – Equipment Operator/ Distribution Mechanic
    - Dustin Sexsmith – Planning & Design Technologist 2
    - Norman Allen – Distribution Mechanic
    - Shawn Lund – Customer Service Technician 1
    - Bryan Neufeld – Distribution Service Agent
    - Denver Manderson – Distribution Mechanic
  - **Rodney Epp** – Operations Manager, Interior North
    - Michael Kettles – Customer Service Technician 1
    - Troy Wisted – Customer Service Technician 1
    - Christopher Baker – Customer Service Technician 1
    - Allyson Lindemann – Field Operations Assistant
    - James Dean – Pressure & Measurement Apprentice
    - Hugh Armstrong – Pressure & Measurement Apprentice
    - Quentin Haugland – Customer Service Technician 1
    - Lloyd Schachtel – Commercial Customer Service Technician
    - Neil Mackay – Distribution Service Agent
    - Lukas Mertelik – Customer Service Technician 1
    - Douglas Harfman – Operations Technician
    - Allen Belanger – Customer Service Technician 1
    - Patric Michael Hale – Customer Service Technician 1
    - Chris Schulte – Pressure, Measurement & Controls Tech
    - Scott Parsons – Customer Service Technician 1
    - Ryan Brown – Customer Service Technician 1
    - Ken Gerow – Customer Service Technician 1
    - Ken Mann – Customer Service Technician 1
    - Connor Bailey – Customer Service Technician 2
    - Brian Joly – Customer Service Technician 1
    - Kerri Ellison – Field Operations Assistant
    - Kelly Lang – Pressure, Measurement & Controls Tech
  - **Michael Parks** – Operations Manager, Interior North
    - Michael Forsyth – Pressure & Measurement Apprentice
    - Olevia Albert – Field Operations Assistant
    - Jean-Sebastien Rodrigue – Customer Service Technician 1
    - Robert Bagg – Distribution Service Agent
    - Christopher Kleven – Customer Service Technician 2
    - Darren Lewis – Customer Service Technician 2
    - Robert Flynn – Customer Service Technician 1
    - Brian Bauer – Operations Technician
    - Perry Kropp – Customer Service Technician 1
    - Mike Worton – Customer Service Technician 2
    - David Seaby – Customer Service Technician 1
    - Ross Embury – Customer Service Technician 1
    - Craig Parks – Commercial Customer Service Technician
    - Lloyd Anderson – Customer Service Technician 1
    - Phillip Brewer – Commercial Customer Service Technician
    - Michael Clark – Customer Service Technician 1
    - Denise Stanley – Field Operations Assistant
    - Greg Dancy – Customer Service Technician 1
    - Don Pickering – Customer Service Technician 1

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Lovejoy Nazareth
Manager, Projects – Geospatial

- **Sophia D'Amato** – Operations Support Representative 3
- **Megan Kaulius** – Operations Support Representative 3
- **Atoine Archie** – Operations Support Representative 2
- **Farhad Dehghani** – Operations Support Representative 2
- **Gonul Guvenc** – Operations Support Representative 2
- **Younghun Kim** – Operations Support Representative 2
- **Roderick Torres** – Operations Support Representative 2
- **Jason Sperling** – GIS Drafter 1
- **Hedayat Paknejad** – Operations Support Representative 2
- **Joseph Vinluan** – GIS Drafter 1
- **Nevine Saad** – Operations Support Representative 3

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Jimmy Yip
Data Integrity Manager

- Kelly Zaurrini — Operations Support Representative 3
- Regina Shree — Operations Support Representative 3
- Brittany Lofgren — Operations Support Representative 2
- Terry Stellar — Operations Support Representative 2
- Tiago Pereira — Operations Support Representative 2
- Verna Fraser — Operations Support Representative 2
- Antoinette Moliere — Operations Support Rep Workleader
- Darlene Mulholland — Operations Support Representative 2
- Leanne Merritt — Operations Support Representative 2
- Sophia Birkbeck — Operations Support Representative 2
- Jose Cusi — Operations Support Representative 2
- Beverly Kirby — Operations Support Representative 2
- Christine Lyster — Operations Support Representative 3
- Jennielee Santiaguel — Operations Support Representative 3
- Kirsten Cheng — Operations Support Representative 2
- Nancy Findlater — Operations Support Representative 2
- Lynette Bigelow — Operations Support Representative 3
- Mandy Ram — Operations Support Representative 3
- Linda Tosin — AM/FM Completions Work Leader
- Marilyn Spier — Operations Support Representative 3
- Enrico Custodio — Operations Support Representative 2
- Jennifer Williams — Operations Support Representative 2
- Parmjit (Puma) Minhas — Operations Support Representative 2

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Lloyd Lamont
Operations Manager, Fraser Valley

- Scott Lowes, Customer Service Technician 1
- David Cooper, Customer Service Technician 1
- Roderick Johnston, Customer Service Technician 1
- Mark Donnery, Customer Service Technician 1
- Michael Cooper, Customer Service Technician 1
- Kristopher Spencer, Customer Service Technician 1
- Duane Mrak, Customer Service Technician 1
- Guido Borrelli, Distribution Service Agent
- James Livingstone, Customer Service Technician 1
- Allen Madsen, Customer Service Technician 1
- Christopher Colpitts, Customer Service Technician 1
- Husty Lang, Customer Service Technician 2
- Robert Moore, Customer Service Technician 1
- Keegan Prieur, Customer Service Technician 1
- Kevin Clingwall, Customer Service Technician 1
- Rick Parker, Customer Service Technician 1
- John Griffith, Customer Service Technician 1
- David Isaac, Customer Service Technician 1
- Brian Ginther, Customer Service Technician 1
- Gregory Steinmann, Customer Service Technician 1
- Carlo Lanfranchi, Commercial Customer Service Technician

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

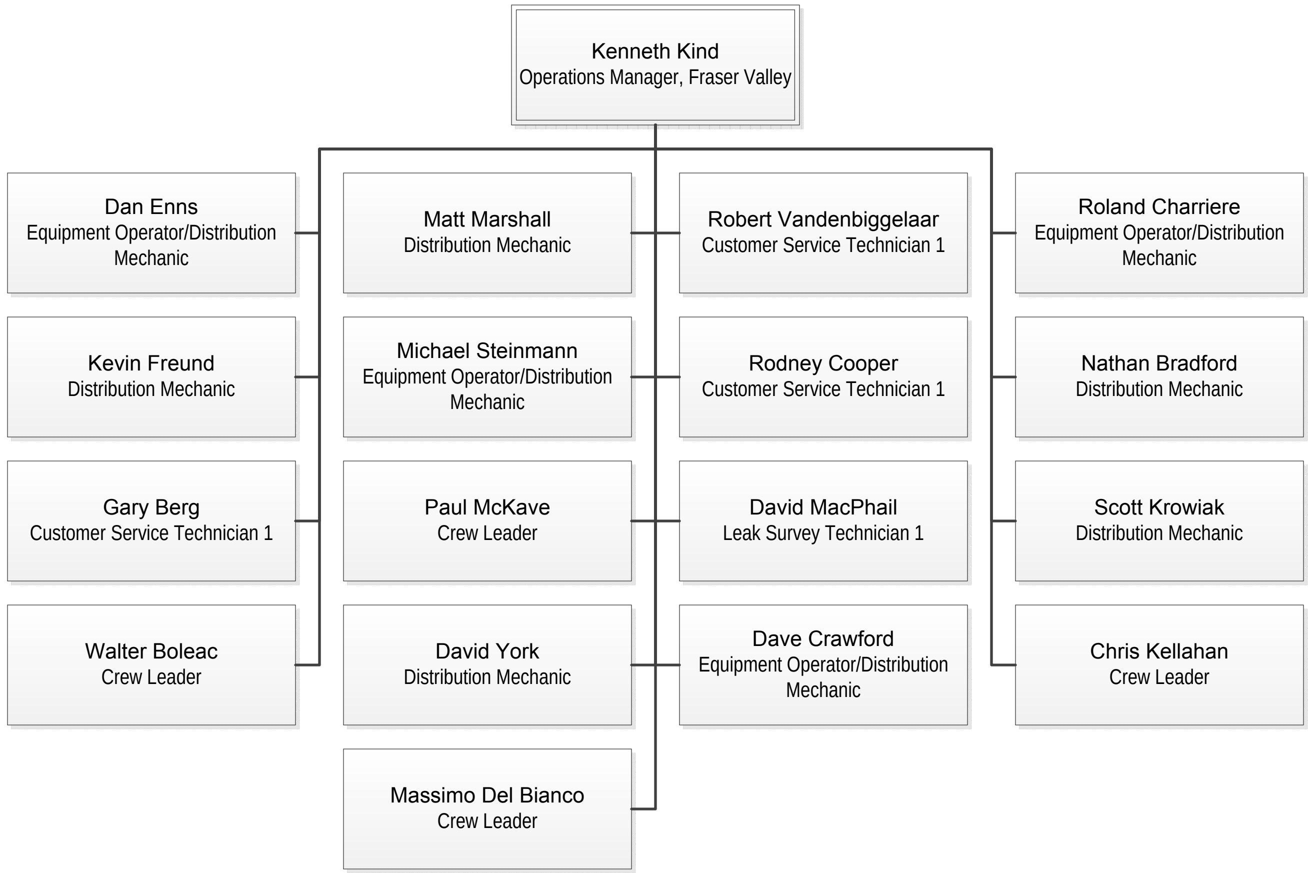
As at June 30, 2013

- **Terry Takashima** — Operations Manager, Fraser Valley
  - Scott Hamill — Crew Leader
  - Dan Albert — Crew Leader
  - Cameron Watson — Customer Service Technician 1
  - Christopher Peppard — Distribution Mechanic
  - Travis Van der Horst — Equipment Operator/Distribution Mechanic
  - Kristopher Nyberg — Equipment Operator/Distribution Mechanic
  - Victor Doucette — Distribution Service Agent
  - Rick MacLeod — Customer Service Technician 1
  - Kory Teesdale — Distribution Mechanic
  - Paul Cameron — Distribution Mechanic
  - Jordan Skidmore — Distribution Mechanic
  - Jatinder (Jay) Jassal — Customer Service Technician 1
  - Steven Skaling — Distribution Mechanic
  - Jason Knoblauch — Distribution Mechanic
  - Jeffrey Klimek — Crew Leader
  - Scott Carter — Customer Service Technician 1

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Gianni Del Bianco** – Operations Manager, Pipeline
  - Tracy Grigg – Transmission Compliance Assistant
  - William Friedrick – Pipeline Technician 1
  - Evan Milliard – Pipeline Technician 2
  - Ted Kuhn – Pipeline Technician 1
  - Jeff Wicks – Pipeline Technician 2
  - Steven Tosh – Pipeline Technician 2
  - Gene Gendron – Pipeline Technician 2
  - Patrick Beaton – Pipeline Technician 2
  - Brian Christianson – Pipeline Technician 2
  - Bruce Dayton – Pipeline Technician 2

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

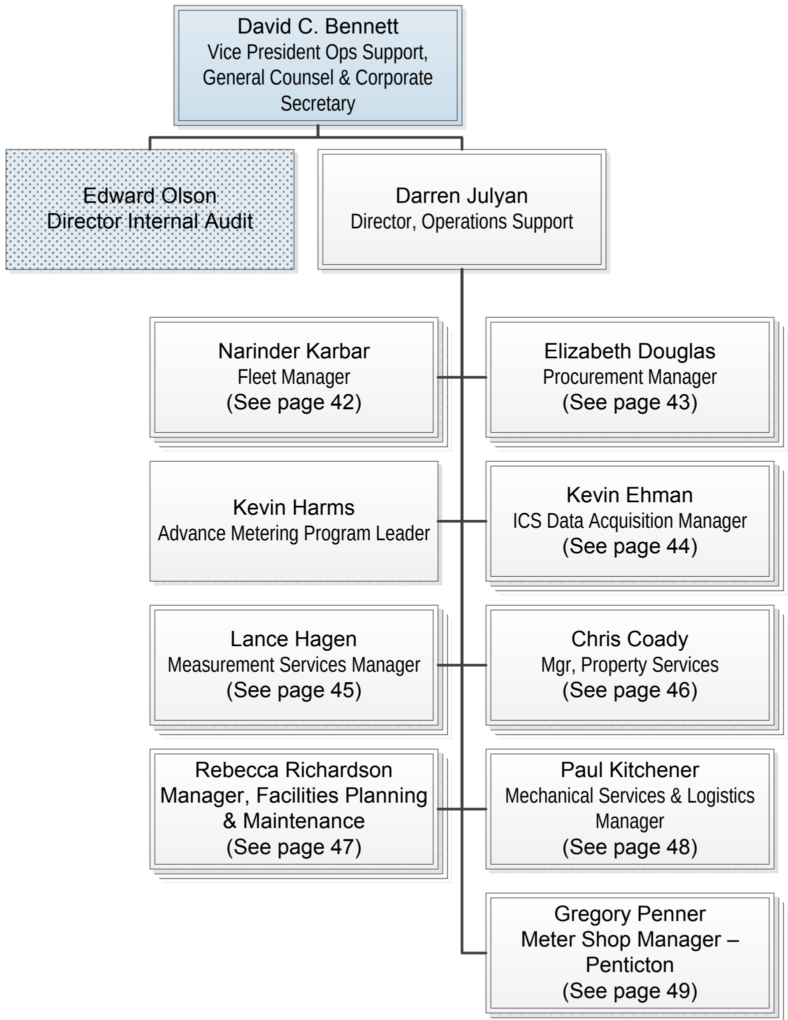
As at June 30, 2013

- **Terry Zazula** – Operations Manager, Fraser Valley
  - Michael Enns – Equipment Operator/Distribution Mechanic
  - Willie Giesbrecht – Equipment Operator/Distribution Mechanic
  - Darryl Thompson – Crew Leader
  - Ronald Child – Customer Service Technician 1
  - Trevor Patrick – Distribution Mechanic
  - David Brubacher – Customer Service Technician 1
  - Anthony Sadowski – Equipment Operator 1
  - Michael Clifford – Customer Service Technician 1
  - Gary Shields – Customer Service Technician 1
  - Gary Hansen – Customer Service Technician 1
  - Billy Lundstrom – Crew Leader
  - Ian Kirkness – Equipment Operator/Distribution Mechanic
  - Steven Markle – Distribution Mechanic
  - Corey Beale – Distribution Mechanic
  - Robert McKeating – Crew Leader
  - Matthew Halladay – Distribution Mechanic
  - Debra Gibson – Distribution Mechanic
  - William Mitchell – Crew Leader
  - Keith Roberts – Distribution Service Agent
  - Randall Schumaker – Paving Foreman
  - Richard McKeating – Distribution Mechanic
  - Darcy Sinclair – Distribution Mechanic
  - Keith Douglas – Equipment Operator/Distribution Mechanic
  - Darrell Albert – Customer Service Technician 1

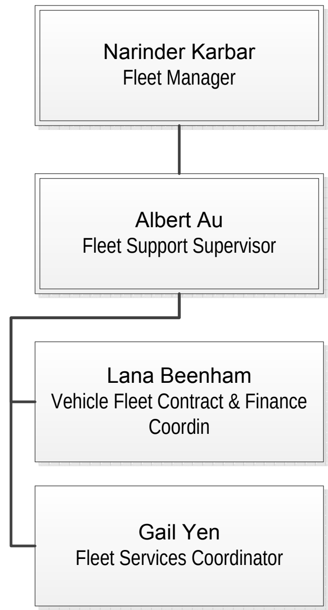
NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



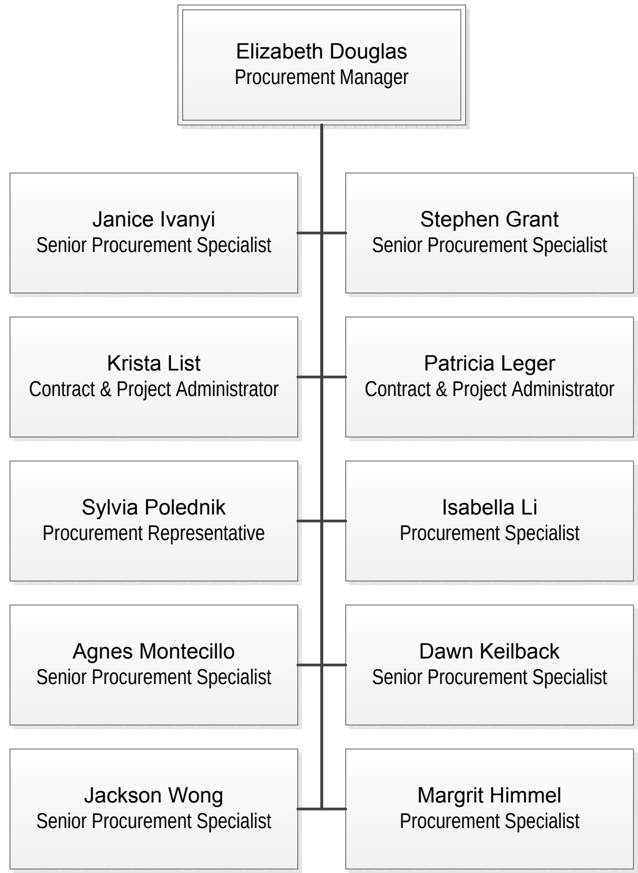
NOT a FEI employee



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

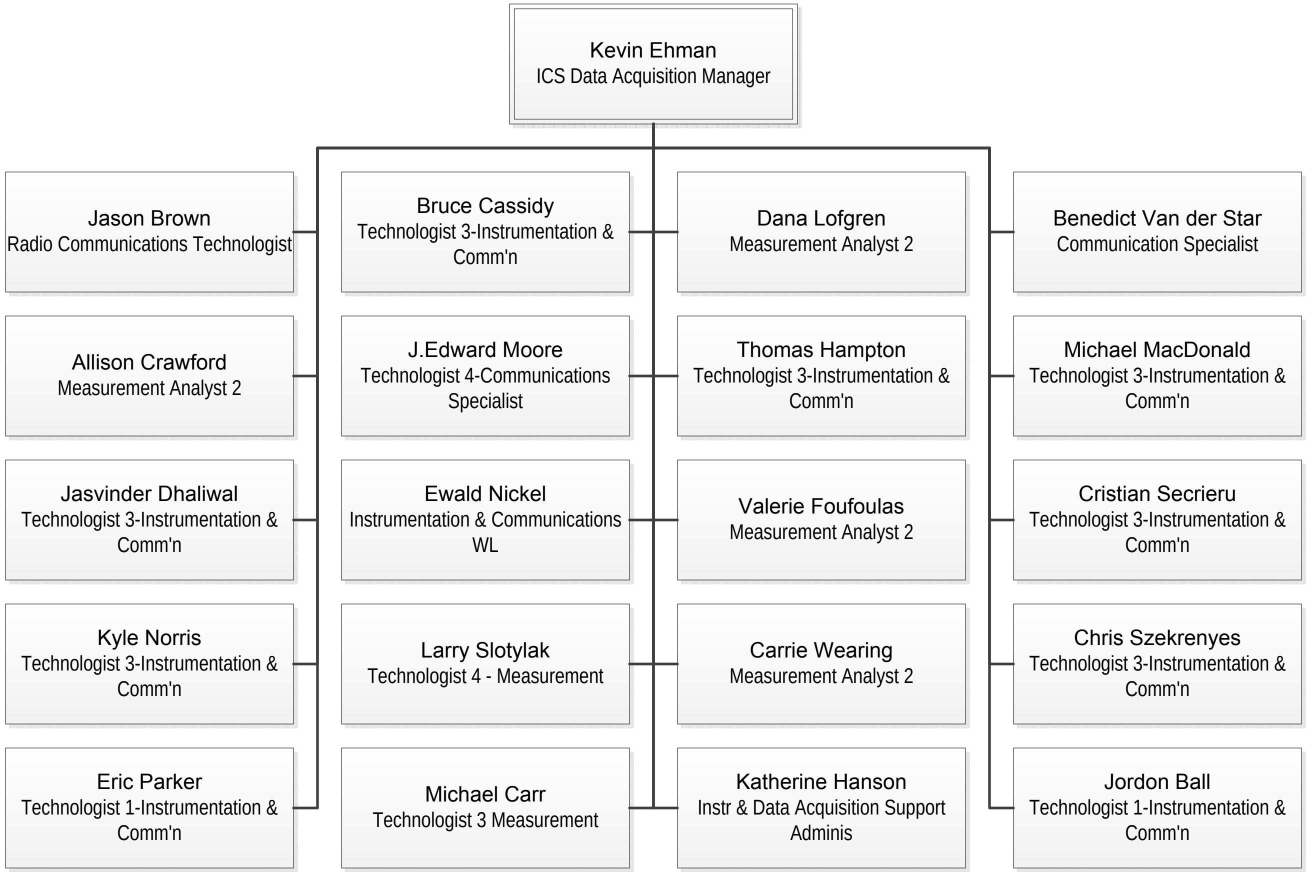
As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Lance Hagen
Measurement Services Manager

- **Katherine Horvatincic** – Measurement Business Analyst
- **Eric Amundson** – Technologist 3 Measurement
- **Cheryl Cote** – Measurement Services Business Analyst
- **Dawne Marcoux** – Operations Support Assistant
- **Denise Holowenko** – Operations Support Assistant
- **Donalene Clarke** – Operations Support Assistant
- **Ryan Steele** – Measurement Services Business Analyst
- **Barbara Russo** – Measurement Technologies Assistant
- **Mike Hepso** – Technologist 3 Measurement
- **Shawn (Shahryar) Nouraei** – Technologist 4 - Quality Assurance WL
- **Joshua Smith** – Technologist 3 Measurement

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Chris Coady
Mgr, Property Services

- **Jenny Mingo** – Technologist 4 - Environmental Support
- **Corinne Allan** – Transmission Permit Representative
- **Cristina Vieira** – Right-of-Way Services Rep.
- **Colleen Bohun** – Lands Representative Work Leader
- **Lorne Sandstrom** – Right of Way Project Coordinator
- **Norman Stickelmann** – Property Tax Specialist
- **Mosaddeque (Sami) Ahmed** – Pipeline Right of Way Representative
- **Alisa Corscadden** – Lands Administrator
- **Shannon Favaro** – Lands Representative
- **Patty Roney** – Lands Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Rebecca Richardson
Manager, Facilities Planning & Maintenance

- Graham West — Facilities Administration Manager
  - Katlyn Sayer — Office Services Clerk
  - Julie Johnson — Switchboard Operator/Recept
  - Rhea Vaughan — Office Services Clerk
  - Ivy Yuen — Office Services Clerk
  - Helen Novakowski — Office Services Leader
- Steve Dosanjh — Facilities Maintenance Manager
  - David Mulligan — Facilities Technician
  - Alireza Ranjbaran — Electrician
  - Peter Hirvonen — Electrician
  - Ed Smith — BTR Facilities Technician
  - Stanley Vernon — Building Maintenance Worker
- Sadaf Sobhani-Gerbrandt — Facilities Assistant
- Hazel-Anne Vincent — Facilities Coordinator
- Hilary Lorage — Facilities Coordinator
- Denis Ryan — Facilities Coordinator
- Lucia Chan — Facilities Maintenance Analyst

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Paul Kitchener
Mechanical Services & Logistics Manager

- Brian Elliott — Fitter Welder 1
- Hariklea Karamessinis — Operations Support Assistant
- Adelaida Coltellaro — Operations Support Assistant
- Mariano Fidanza — Shop Mechanic 1 - Machine
- Terrence Scramstad — Fitter Welder 1
- Timothy Schill — Material Handler
- Daniel Craig — Fitter Welder 1
- David Craig — Warehouse & Delivery Leader
- David Woods — Materials Shipper/Receiver
- Philip Chalut — Materials Shipper/Receiver
- Steven Poloni — Material Handler
- L.Garth Gendron — Yard Foreman
- Robert Boisclair — Shop Mechanic 1 - Prefab
- Brian Mclean — Fitter Welder 1
- Eldon Vogt — Design Machinist

- Douglas Pedersen — Shop Mechanic 1
- Derek Naudi — Shop Mechanic 2 - Prefab
- Dean Ashlie — Fitter Welder 1
- Steven Mardyn — Mechanical Foreman - Prefab
- Ron Smart — Shop Mechanic 1 - Prefab
- Dennis Kahri — Materials Truck Driver
- Harry Grewal — Material Handler
- Mark A Robinson — Materials Shipper/Receiver
- James Johnston — Materials Shipper/Receiver
- Angela Giotto — Inventory Analyst 2
- Stephen Short — Material Handler
- George Lum — Design Machinist
- Miguel Jimenez — Commercial Customer Service Technician
- Glen Ulriksen — Shop Mechanic 1 - Machine
- Mel Losier — Shop Mechanic 1
- Steven Bennett — Fitter Welder 1

- Randy Readman — Fitter Welder 1
- Brad Roy — Materials Truck Driver
- Frank Demichina — Materials Truck Driver
- Leo Japitana — Material Handler
- Dan Arseneault — Shop Mechanic 1 - Prefab
- Gerard Gerrior — Materials Truck & Trailer Operator
- Derek Robb — Senior Logistics Handler
- Kelly Barton — Shop Assistant
- Anthony Easton — Fitter Welder 1
- Josef Bauer — Shop Mechanic 1 - Machine
- Nebojsa Deretic — Painter
- Bernard Vaillancourt — Fitter Welder 1
- Anthony Olivieri — Shop Mechanic 1 - (Weld Shop)
- Kyle Salter — Fitter Welder 2
- Christopher Lumsden — Fitter Welder 1

- John Peterson — Mechanical Foreman-Welding
- Sean Ballance — Fitter Welder 1
- Bruce Baker — Mechanical Foreman-Machine Shop
- Denis Forest — Materials Truck & Trailer Operator
- Eric Tan — Inventory Analyst 2
- Michael Struss — Fitter Welder 1
- William Watson — Shop Assistant
- Brian Heggs — Material Handler
- Stephen Robinson — Material Handler
- Hal Gates — Fitter Welder 1
- Edgar Chow — Material Handler
- Ian Burnett — Senior Logistics Handler
- Jitendra Singh — Materials Truck Driver
- James Schwab — Shop Mechanic 1 - Prefab
- Tim George — Material Handler

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Gregory Penner** – Meter Shop Manager – Penticton
  - Kane Oaten – Measurement Mechanic 2 - Start
  - Richie Guilfoyle – Measurement Mechanic 1
  - Fred McCabe – Senior Logistics Handler
  - Brett Gawne – Measurement Mechanic 1
  - Paul O'Neill – Measurement Shop Leader
  - Donavon Maxted – Measurement Technician
  - Daniel Unruh – Measurement Mechanic 1
  - Gregory Kyle – Measurement Mechanic 1
  - Gerry Dilling – Measurement Mechanic 1
  - Vincent Clifton – Measurement Mechanic 1
  - D.Eric Janzen – Measurement Technician
  - Leonard Popeniuk – Measurement Technician
  - Ronald Shewchuk – Measurement Shop Leader
  - Paul Ouellette – Measurement Technician
  - Tracy Hesla – Measurement Mechanic 1
  - Ivan Jurcic – Shop Assistant
  - Jack Horning – Measurement Mechanic 2 - 18
  - John Gordin – Measurement Mechanic 1
  - Ben Viefhues – Measurement Mechanic 1
  - Tim Lyons – Materials Shipper/Receiver
  - Paul Nelson – Measurement Shop Leader
  - Jonathan Loeppky – Painter

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

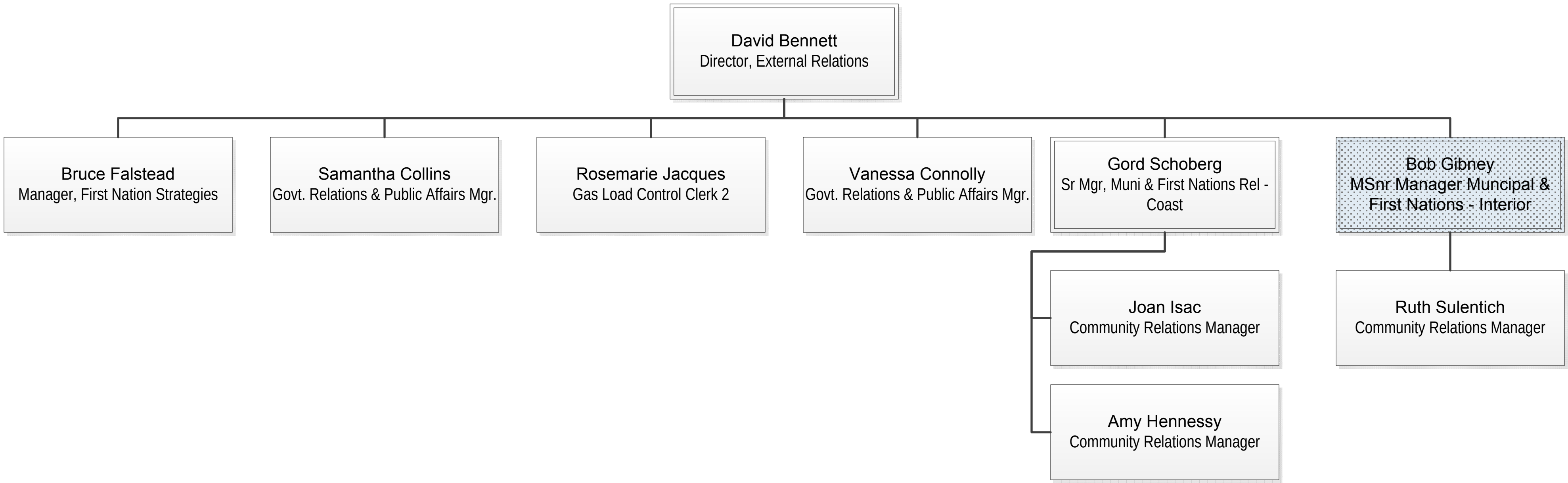
As at June 30, 2013

- **Douglas Stout**
  VP, Energy Solutions & External Relations
  - Maureen Trainor
    Executive Assistant
  - David Bennett
    Director, External Relations
    (See page 51)
  - John Turner
    Director, Energy Solutions
    (See page 52)
  - Sarah Smith
    Director, EEC
    (See page 53)
  - Jason Wolfe
    Director, Market Development
    (See page 54)
  - Gareth Jones
    Director, Business Development
    (See page 55)
  - Joyce Wagenaar
    Director, Communications
    (See page 56)

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

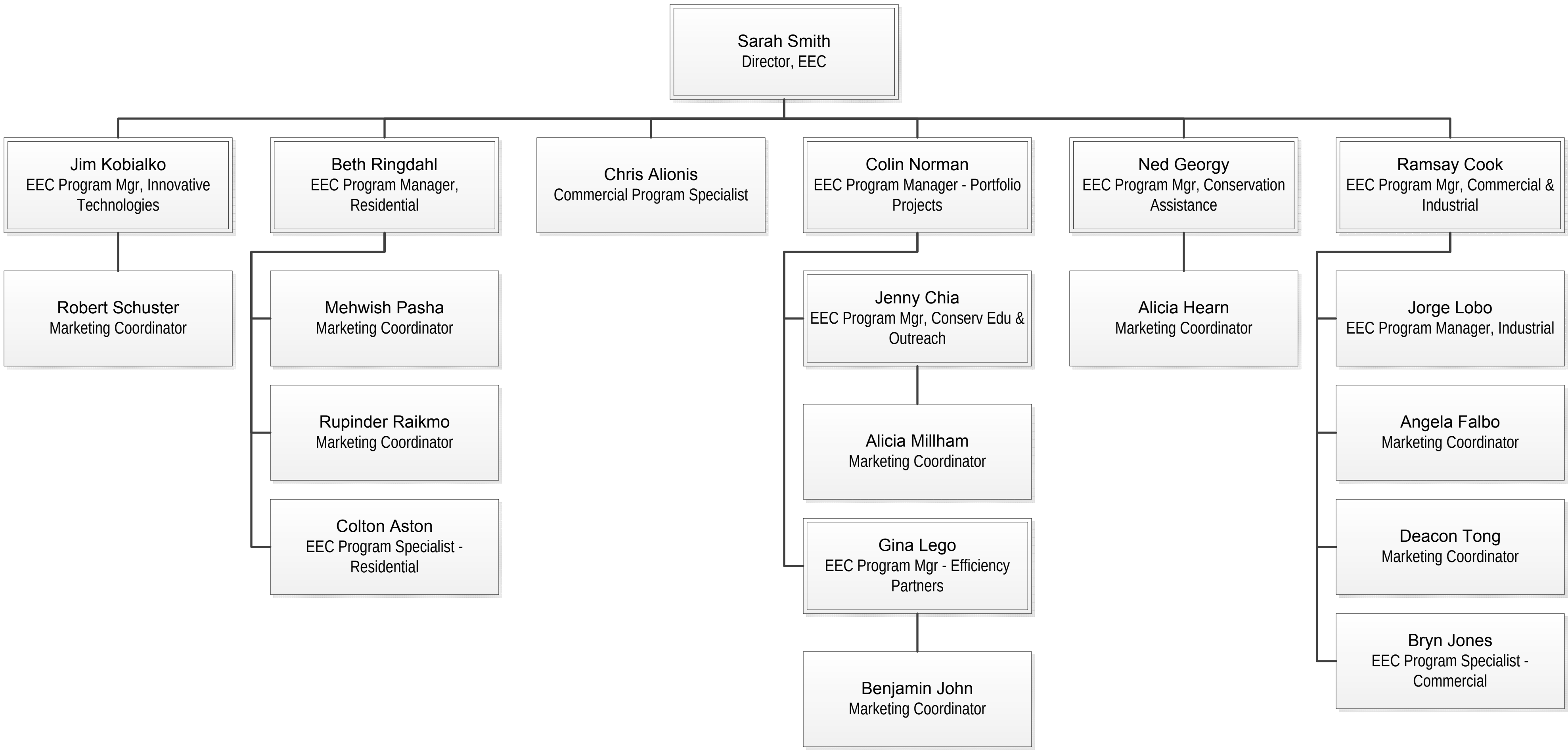
As at June 30, 2013

- **John Turner** – Director, Energy Solutions
  - **Courtney Hodson** – Product and Services Marketing Manager
  - **Heather Moniz** – Sales Support Assistant
  - **Kristen Mucha** – Sr Mgr, Community, C&I Energy Solutions
    - **Xu Ding** – Commercial Program Specialist
    - **Kevin Hodgins** – Mgr,Commercial & Indust Energy Solutions
      - **Rajoo Jagtap** – Commercial & Industrial Account Manager
      - **Douglas Tufts** – Commercial & Industrial Account Manager
      - **Candace Rennie** – Sales Support Assistant
      - **Wesley Nienaber** – Commercial & Industrial Account Manager
      - **Jennifer Coulthard** – C&I Energy Solutions Manager
      - **Mandy Assi** – Commercial & Industrial Account Manager
    - **Nancy Myers** – Community Energy Solutions Manager
    - **Vladimir Kostka** – Community Energy Solutions Manager
  - **Vito Triggiano** – Mgr, Natural Gas Transportation Solution
    - **Georgina Wheatcroft** – Natural Gas Vehicles Account Manager
    - **Will Smith** – Natural Gas Vehicles Account Manager
  - **Jenelle Hameluck** – Product Marketing & Relationship Manager
  - **Robert Anderson** – Sr Mgr,Res & Commercial Energy Solutions
    - **Dan Noel** – Regional Energy Solutions Manager
      - **Christina Treleaven** – EEC Energy Solutions Manager
      - **Michael Liu** – Energy Solutions Manager
      - **Stephanie Yen** – Sales Support Assistant
      - **Benjamin Nishi** – Energy Solutions Manager
      - **Della Bond** – EEC Energy Solutions Manager
      - **Bradley Ricketts** – Energy Solutions Manager
      - **Dean Turner** – Energy Solutions Manager
      - **Wayne Cankovic** – Energy Solutions Manager
    - **Brent Hunt** – Regional Energy Solutions Manager
      - **Wade Benner** – Energy Solutions Manager
      - **Shelley Thomson** – Energy Solutions Manager
      - **Peter Hill** – Energy Solutions Manager
      - **Kerri Lynn Schaefer** – Regional Sales Suppport Assistant

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Jason Wolfe** – Director, Market Development
  - **Ken Ross** – Mgr, Integrated Resource & EEC Reporting
    - Ravneet Sandhu – Tracking & Management Systems Analyst
    - Dana Wong – Integrated Resource Planning Manager
    - Tom Partridge – Integrated Resource Planning Analyst
    - Cindy Wong – EM & V Specialist
    - Jady Peng – EEC Program Development Lead
    - Maud Warner – Reporting & Consultation Analyst
    - Pat Keokongchack – DSM Tracking & Managemnt Systems Analyst
  - **David Bailey** – Customer Energy & Forecasting Manager
    - Shahnaz Shivji – Senior Forecast Analyst
    - Soyean Kim – Senior Forecast Analyst
  - **Brent Graham** – Manager, Energy Products & Services
    - Mike Metza – Manager, Energy Products & Services
    - Rick Kan – Manager, Energy Products & Services
    - Arvind Ramakrishnan – Manager, Energy Products & Services
      - Rachel Chuang – Energy Products & Services Analyst
  - **Bea (Balbir) Bains** – Mgr, Bus Performance & Tech Solutions
    - Dan Bradley – Energy Utilization Manager
    - Anthony Ho – Energy Utilization Manager
    - Jer Min Hsieh – Energy Utilization Manager
  - **David Perttula** – Manager, Market Development
    - Robert Brownell – Business Development Manager
    - Gerald Chan – Market Development Specialist
  - **Cindy Friesen** – Administrative Assistant

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Gareth Jones** – Director, Business Development
  - **Jarek Bekesza** – Manager, Operations & Project Assessment
    - Don Bergler – Mgr, Engineering & Operations Services
    - Richard Marier – Manager, Operations & Project Assessment
    - Ramya Rayaprolu – Engineering Co-op Student
  - **Mark Grist** – Senior Manager, Business Development
    - Janet Devaney – Business Development Manager
    - Manjinder Bains – Business Development Specialist
    - Allison Lunde – Business Development Analyst
    - Steven Hodge – Business Development Manager
    - Prescott Gramm – Business Development Manager
    - Ryan Findlay – Business Development Manager
    - Carmela Devine – Comm, Aboriginal & Gov't Relations Assis
  - **Grant Bierlmeier** – Business Development Manager
    - Stuart MacGillivray – Community Energy Solutions Manager
    - Siraz Dalmir – Community Energy Solutions Manager
    - Anita Lee – Confidential Assistant
  - **Gary Lengle** – Manager, New Product Operations (Gas)
    - Peter Valkenburg – New Product Development Coordinator
    - Adrian Ghelesel – New Product Development Coordinator
    - Rob Newth – NGV Analyst
    - Victor Fe – New Product Development Coordinator
  - **Paul Madsen** – Senior Manager, Project Assessment & Dev
    - Nicola Simon – Project Development Manager
    - Jane Chan – Business Development Manager
    - James Lota – Business Development Manager
    - K. Michael Flaherty – Business Development Manager
    - Kiumars (Ryan) Dibai – Project Development Manager

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

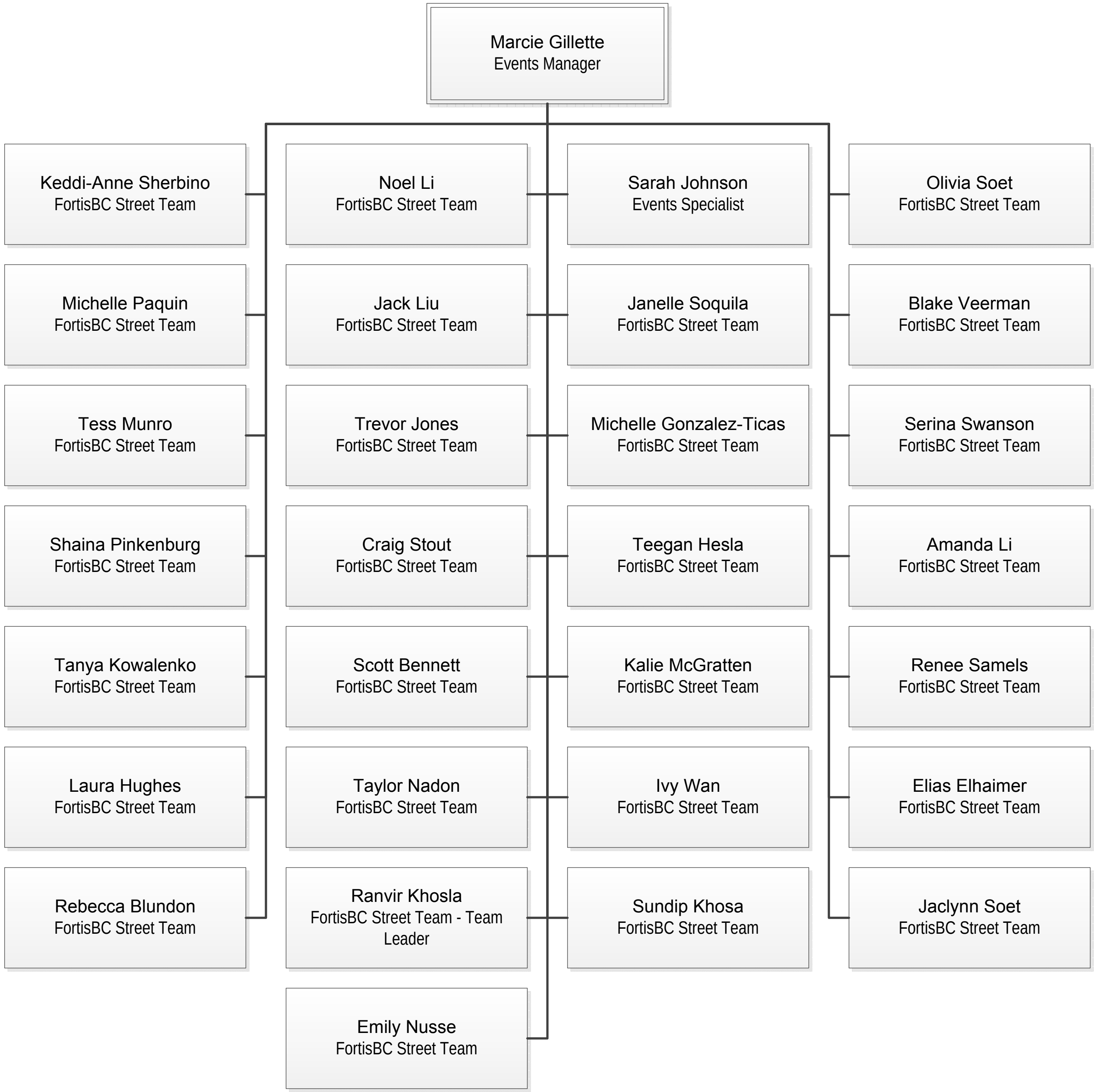
As at June 30, 2013

- **Joyce Wagenaar** – Director, Communications
  - **Bev Macham** – Confidential Assistant
  - **Neal Pobran** – Manager Corporate Communications
    - **Grace Pickell** – Corporate Communications Advisor
  - **Audrey Wang** – Employee Communications Manager
    - **Angela Robertson** – Employee Communications Writer
  - **Donna Gratton** – Manager, C.S. Web & Social Media
    - **Joanne Hunton-Sehdev** – Communications Coordinator
    - **Kristy Paulhus** – Communications Coordinator
  - **Marcie Gillette** – Events Manager (See page 57)
  - **Arlene Whiffin** – Manager, Customer Communications
    - **Lynn Budny** – Designer, Communication Services
    - **Stephanie Montano** – Communications Coordinator
    - **Tony Yu** – Communications Coordinator
    - **Cameron Craig** – Lead Designer, Communication Srvcs
    - **Denis Pichii** – Designer
    - **Nicole Frohloff** – Writer/Researcher
    - **Leanne Fulton** – Designer, Communication Services
    - **Leanne Carey** – Communications Specialist
    - **Joan Churchill** – Writer/Researcher
  - **Michael Allison** – Corporate Communications Advisor

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

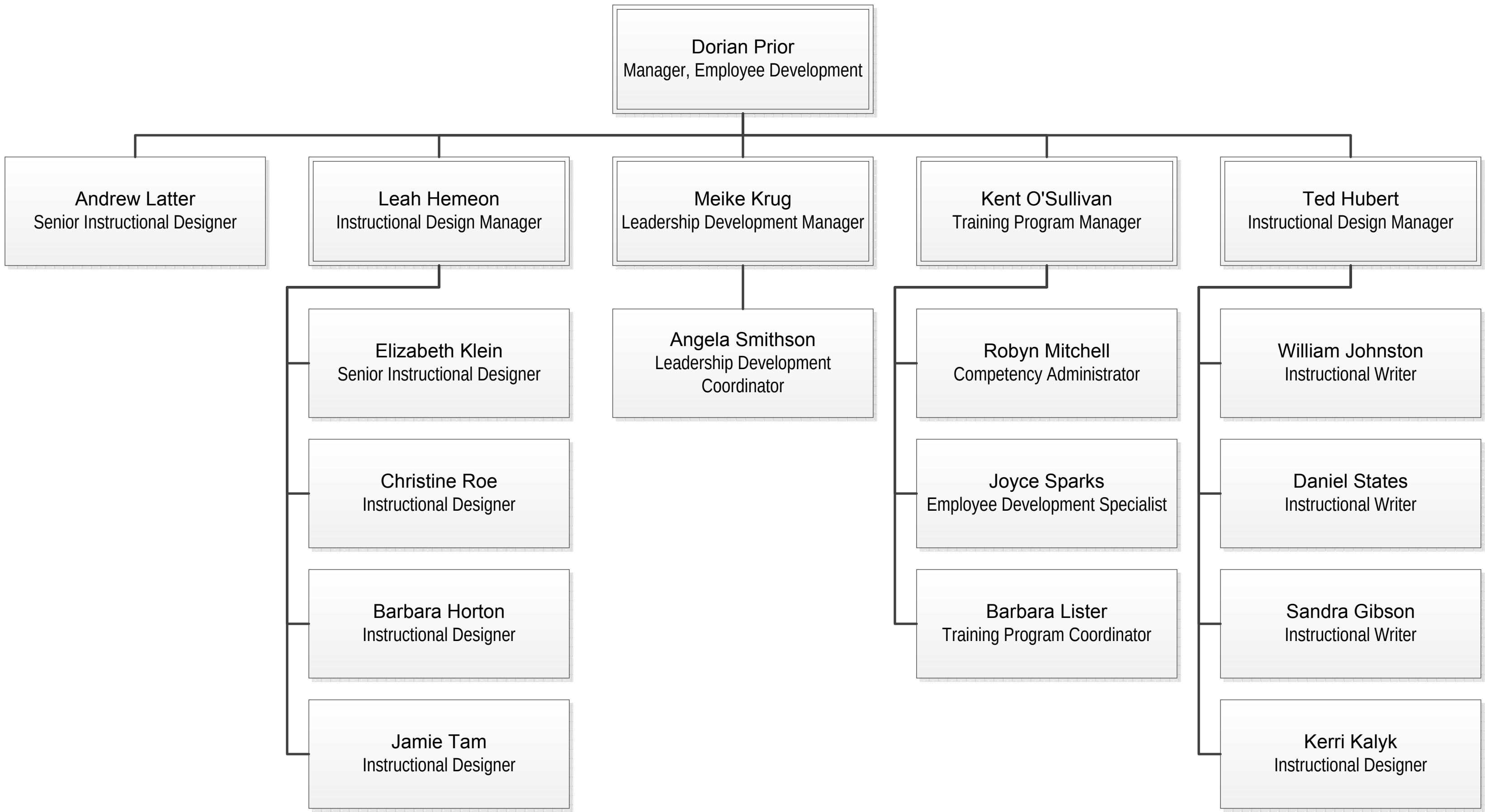
As at June 30, 2013

- **Michael Mulcahy** – Executive Vice President, HR, Customer & Corporate Services
  - **Jody Drope** – Chief Human Resources Officer
    - Judy Forshner – Human Resources Business Assistant
    - Dorian Prior – Manager, Employee Development (See page 59)
    - Rita Ludwig – Director Employee Relations (See page 60)
    - Andrea Best – Director, Employee Services (See page 61)
    - Jason McIvor – Leader, Corporate HR Projects
  - **Tom Loski** – VP, Customer Service
    - Celeste Arrieta – Executive Assistant
    - Dawn Mehrer – Director, Customer Contact Centres (See page 62)
    - Meena Khangura – Manager, Business Performance & Finance
    - Mark Warren – Director Customer Service Technology & Systems (See page 81)
    - Nicole Vandenakker – Senior Manager, Billing Operations (See page 82)
  - **Timothy Swanson** – Director, Information Systems
    - Carol Gresty – Executive Assistant
    - Allan Santano – Solutions Architect (See page 86)
    - Robert Croston – Manager, IT PMO (See page 87)
    - Darwin Anderson – Infrastructure Manager (See page 88)
    - Mia Uy – Contract & Finance Coordinator B&ITS
    - Frans Luit – Manager, Enterprise Applications (See page 89)
    - Mark Gillette – IT Operations Manager (See page 90)
    - Donald H. Smith – Enterprise Support Manager
    - Raveena Nat – Business Systems Planning Manager (See page 91)
    - Andrew Kwok – Application Support & Delivery Manager (See page 92)
  - **Suzana Prpic** – Director, Environment, Health & Safety
    - Michelle Petrusevich – Public Safety Manager
    - Maira Loosemore – Administrator, Environment Health Safety
    - Christine Trefanenko – Mgr, Bus Continuity & Emergency Planning (See page 94)
    - Jennifer Robertson – Environmental Affairs Manager (See page 95)
    - Niall Berry – OH&S & Corporate Security Manager (See page 96)

NOT a FEI employee (shaded boxes: Rita Ludwig, Mark Warren, Allan Santano)

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- Rita Ludwig
  Director Employee Relations
  - Angela Davies
    HR Advisor
  - Bonnie Bragg
    Human Resources & Compensation Advisor
  - Rachel Cather
    HR Advisor
  - Francesca Turrell
    HR Advisor
  - Sylvie Gelinas
    HR Advisor
  - Adrienne Twibill
    HR Advisor
  - Doug Slater
    Manager, Labour Relations
    - Karen Verhaeghe
      Labour Relations Coordinator

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

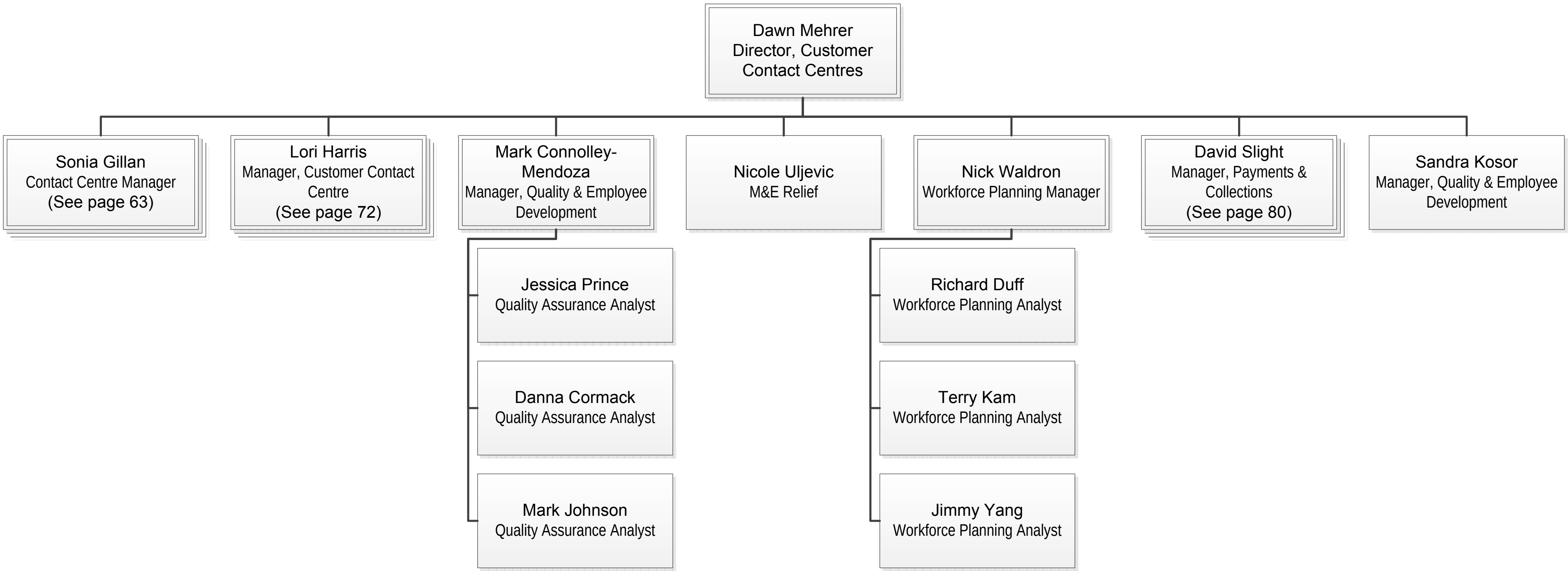
As at June 30, 2013

- **Andrea Best** – Director, Employee Services
  - **Kim Farrell** – Manager, Pension & Benefits
    - Holly Sproxton – Pension & Benefits Analyst
    - Doreen Herbach – Employee Services Representative
    - Natalie Yenson – Employee Services Representative
    - Kim Elliott – Employee Services Representative
    - (Vivien) Wei Ghan Lee – Pension Specialist
    - Amalie Michaux – Employee Services Coordinator
    - Sharel Burns – Employee Services Representative
  - **Beverley MacGillivray** – Manager, HRIS/Payroll
    - Theresa Robinson – Payroll Administrator
    - Claudia Lazar – Time Administrator
    - Elena Shaughnessy – Compensation Analyst
    - Seema Sidhu – M&E Payroll Coordinator
    - Christopher Hsiang – Payroll Administrator
    - Jasmeen Sandhu – Payroll Coordinator
  - **Barb Richardson** – Manager, Talent Sourcing
    - Tiffany Sek – Talent Sourcer
    - Courtnay de Rooy – Talent Sourcer
    - Shelley Onofrechuk – Relief Clerk
    - Erin Geisinger – Talent Sourcer
    - Shauna Campfield – Talent Sourcer
    - Susan Chiu – Talent Sourcer
    - Britta Kurucz – Talent Sourcer
    - Danica LaPierre – Talent Sourcer

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Sonia Gillan** – Contact Centre Manager
  - **Christopher Leavy** – Contact Centre Team Manager (See page 64)
  - **Stephanie Kuo** – Customer Service Process Analyst
  - **Jean Mackay** – Contact Centre Team Manager (See page 65)
  - **Wade Tulak** – Contact Centre Team Manager (See page 66)
  - **Tomokazu Quach** – Contact Centre Team Manager (See page 67)
  - **Heather Loslo** – Contact Centre Team Manager (See page 68)
  - **Bruce Gilson** – Construction Services Contact Centre Mgr (See page 69)
  - **Maxine Hickli** – Contact Centre Team Manager (See page 70)
  - **Rob Goncalves** – Customer Service Process Analyst
  - **Greg Calbick** – Contact Centre Team Manager (See page 71)

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Christopher Leavy** – Contact Centre Team Manager
  - Hitesh Sajwan – Customer Service Representative
  - Puneet Sharma – Customer Service Representative
  - Farhana Ali – Customer Service Leader
  - Ayame Villarroel – Customer Service Representative
  - Humyra Helal – Customer Service Representative
  - Danielle Samels – Customer Service Representative
  - Peter Reyes – Customer Service Representative
  - Daniel Simpson – Customer Service Representative
  - Edgar Ruiz-Ambrosy – Customer Service Representative
  - Carmelita Dela Fuente – Customer Service Representative
  - Megan Blakeley – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Jean Mackay** – Contact Centre Team Manager
  - Aartika Singh – Customer Service Leader
  - Gina Plumridge – Customer Service Representative
  - Susanne Yeh – Customer Service Representative
  - Winnie Ng – Customer Service Representative
  - Angela Gaster – Customer Service Representative
  - Erin Robins – Customer Service Representative
  - Gabriel Emit – Customer Service Representative
  - Sandra Ferguson – Customer Service Representative
  - Megan Pedersen – Customer Service Representative
  - Manjinder Dosanjh – Customer Service Representative
  - Valerie Roy – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Wade Tulak
Contact Centre Team Manager

- **Adam Woods** – Customer Service Representative
- **Karen Birkeland** – Customer Service Representative
- **Katrina Cook** – Customer Service Representative
- **Lawrence Leung** – Customer Service Representative
- **Troy Otway** – Customer Service Representative
- **Parin Khaki** – Customer Service Representative
- **Puspa Mistry** – Customer Service Representative
- **Sarah Elash** – Customer Service Representative
- **Reenu Chand** – Customer Service Representative
- **Dawn Fisher** – Customer Service Leader
- **Tanminder (Tony) Bal** – Customer Service Representative
- **Alison Stimpson** – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Tomokazu Quach** – Contact Centre Team Manager
  - Anne Marie Gray – Collections Representative
  - Jagdeep Kaur – Collections Representative
  - Doreen Singh – Collections Representative
  - Amar Mangat – Collections Leader
  - Mary Georgy – Collections Representative
  - Stephanie Eglitis – Collections Representative
  - Denise Moffatt – Collections Representative
  - Mandy Aujla – Collections Representative
  - Parastoo Sadegh-Tehrani – Collections Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Heather Loslo** – Contact Centre Team Manager
  - Maria George – Customer Service Representative
  - Taranjit Kaur – Customer Service Representative
  - Samir Batala – Customer Service Representative
  - Rochelle McKenzie – Customer Service Representative
  - Trevor Gourlie – Customer Service Representative
  - Dominic Yip – Customer Service Representative
  - Omer Esteron – Customer Service Leader
  - Po Ching (Jerry) Kuo – Customer Service Representative
  - Genarose Tolentino – Customer Service Representative
  - Emmet McIlvenna – Customer Service Representative
  - Jarad Beckett – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Bruce Gilson
Construction Services Contact Centre Mgr

- **Christine Bauer** – Construction Customer Representative
- **Colleen Redekop** – Construction Customer Representative
- **Elaine Webster** – Construction Customer Representative
- **Charnjit Dhillon** – Construction Customer Representative
- **Donalie Bears** – Construction Customer Representative
- **Vera Spasojevic** – Construction Customer Representative
- **Cheryl Hyde** – Construction Customer Representative
- **Lori Dearden** – Construction Customer Representative
- **Kim Copland** – Construction Customer Representative
- **Carolynne Olsen** – Construction Customer Representative
- **Katarzyna Liniewska** – Construction Customer Representative
- **Wendie Parrish** – Construction Customer Representative
- **Sabrina Castagno** – Construction Customer Representative
- **Barbara Laidlaw** – Construction Customer Representative
- **Roger Cuyugan** – Construction Customer Representative
- **Deepak Virk** – Construction Customer Rep Workleader

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Maxine Hickli** – Contact Centre Team Manager
  - [redacted] – Customer Service Representative
  - Sandeep Parmar – Customer Service Representative
  - Gurjit Gill – Customer Service Representative
  - Rohan Matts – Customer Service Representative
  - Daljit Dhaliwal – Customer Service Representative
  - Rafael Diy – Customer Service Representative
  - Malavika Thomas – Customer Service Representative
  - Vik Saggu – Customer Service Representative
  - Sandra Allan-Wagnitz – Customer Service Leader
  - Sara Huang – Customer Service Representative
  - George Nicol – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Greg Calbick** – Contact Centre Team Manager
  - Alicia Singh – Customer Service Administration Clerk
  - Irene Kumar – Customer Service Leader
  - Deirdre Ross – Customer Service Leader
  - Suzie Pereira – Customer Service Representative
  - Cynthia Garley – Customer Service Leader
  - Deanna Loster – Customer Service Administration Clerk
  - Kathryn Prinz – Billing Assistant
  - Cara Logan – Customer Service Administration Clerk
  - Michelle Craig – Customer Service Administration Clerk
  - Jonetha Julian – Customer Service Leader
  - Christina Singh – Customer Service Leader
  - Sara Lasure – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Lori Harris
Manager, Customer Contact Centre

- **Angela Dejonghe** – Confidential Administrative Assistant
- **Madeleine White** – Contact Centre Team Manager (See page 73)
- **Shirley Helm** – Contact Centre Team Manager (See page 74)
- **Sarah Bethune** – Contact Centre Team Manager (See page 76)
- **Mauricio Plata** – Contact Centre Team Manager (See page 77)
- **Richard Bethell** – Contact Centre Team Manager (See page 78)
- **Gregory Warawa** – Contact Centre Team Manager (See page 79)

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Madeleine White
Contact Centre Team Manager

- **Scott Link** – Customer Service Representative
- **Martin Istok** – Customer Service Representative
- **Tonya Morgan** – Customer Service Representative
- **Nathan Wainwright** – Customer Service Representative
- **Lorraine Walton** – Senior Customer Service Representative
- **Jordan De Medeiros** – Senior Customer Service Representative
- **John Hill** – Senior Customer Service Representative
- **Joshua Maurits** – Customer Service Representative
- **Nicole Yeo** – Customer Service Representative
- **Maleen Nelson** – Customer Service Representative
- **Kevin Johnson** – Customer Service Leader

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

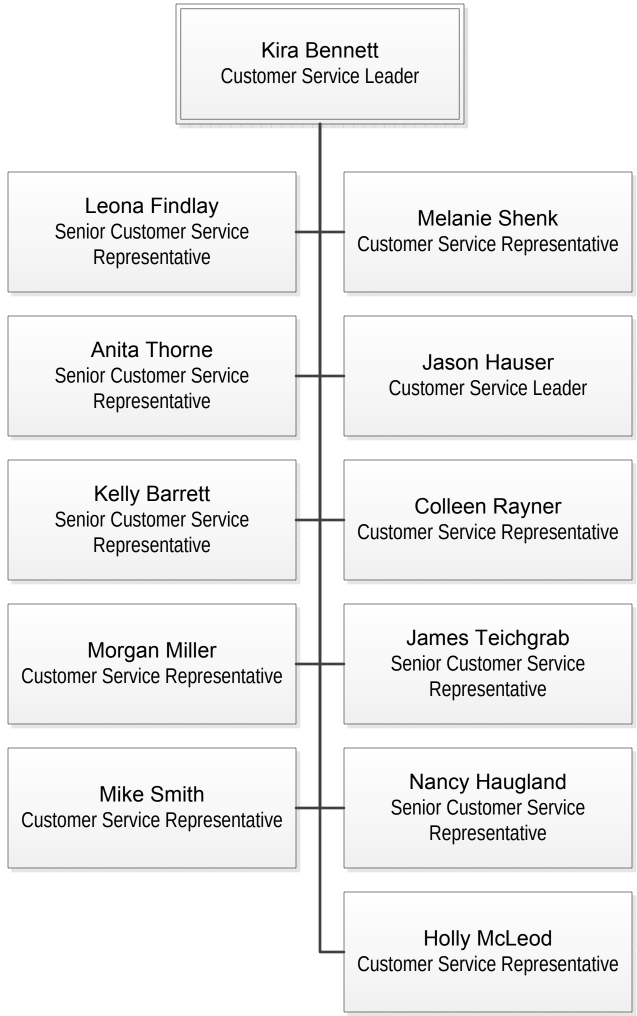
As at June 30, 2013

- **Shirley Helm** – Contact Centre Team Manager
  - **Brittany Graham** – Customer Service Administration Clerk
  - **Sara Goulet** – Customer Service Leader
  - **Jodi Cain** – Customer Service Leader
  - **Kathy Vollin** – Customer Service Leader
  - **Cherie Herbert** – Customer Service Representative
  - **Ginette Kleiner** – Senior Customer Service Representative
  - **Nadine Fortin** – Customer Service Representative
  - **Kira Bennett** – Customer Service Leader (See page 75)
  - **Taralynn Danes** – Customer Service Representative
  - **Bryce Williams** – Senior Customer Service Representative
  - **Cathy Forsyth** – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Sarah Bethune** – Contact Centre Team Manager
  - John West – Customer Service Representative
  - Jason Peacock – Customer Service Representative
  - Kathleen Taylor – Senior Customer Service Representative
  - Kelly Chabot – Customer Service Representative
  - Oluwaseun Oyebanjo-Odofin – Customer Service Representative
  - Jolene Crosina – Customer Service Leader
  - Roxanne Bolduc – Customer Service Representative
  - Krystal Wiebe – Senior Customer Service Representative
  - Jeni O'Meara – Customer Service Representative
  - Patricia Wheeler – Customer Service Representative
  - Angie Neufeld – Senior Customer Service Representative
  - Christen Gardner – Customer Service Representative
  - Deanna Wintemute – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Mauricio Plata** – Contact Centre Team Manager
  - **Rick Frederickson** – Customer Service Leader
  - **Satbeer Bains** – Senior Customer Service Representative
  - **Josiah Barton** – Senior Customer Service Representative
  - **Jordan Killam** – Senior Customer Service Representative
  - **Puneet Hayer** – Customer Service Representative
  - **Echo Somerville** – Customer Service Representative
  - **Yvonne Champion** – Customer Service Representative
  - **Nicole Neufeld** – Customer Service Representative
  - **Melissa Martin** – Customer Service Representative
  - **Erin Forsberg** – Customer Service Representative
  - **Katrina Keller** – Customer Service Representative
  - **Crystal Lefebure** – Customer Service Representative
  - **Natalie Anthony** – Senior Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Richard Bethell
Contact Centre Team Manager

- **Stacey Young** – Customer Service Representative
- **Miguel Gutierrez** – Customer Service Representative
- **Ash-lee Palmer** – Customer Service Representative
- **Rupinder (Ruby) Bhullar** – Customer Service Leader
- **Brenda Mclean** – Customer Service Representative
- **Matthew Comparelli** – Customer Service Representative
- **Md Samsul (Sam) Hoque** – Customer Service Leader
- **James Rodrigues** – Customer Service Representative
- **Zlatka Young** – Customer Service Representative
- **Lori Lan** – Customer Service Representative
- **Olibert Bustamante** – Customer Service Representative
- **Karam Soomro** – Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Gregory Warawa** — Contact Centre Team Manager
  - Andra Zazulak — Customer Service Representative
  - Ann Kurtz — Customer Service Leader
  - Nicole Schultz — Customer Service Representative
  - Danielle McPherson — Customer Service Representative
  - Kaylene Stewart — Customer Service Representative
  - Judy Blishen — Customer Service Representative
  - Cassy Gibson — Customer Service Representative
  - Jason Wiebe — Senior Customer Service Representative
  - Mairi Broadbent — Customer Service Representative
  - Adam Lovell — Customer Service Representative
  - David Kushniruk — Customer Service Representative
  - Kasandra Christie — Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

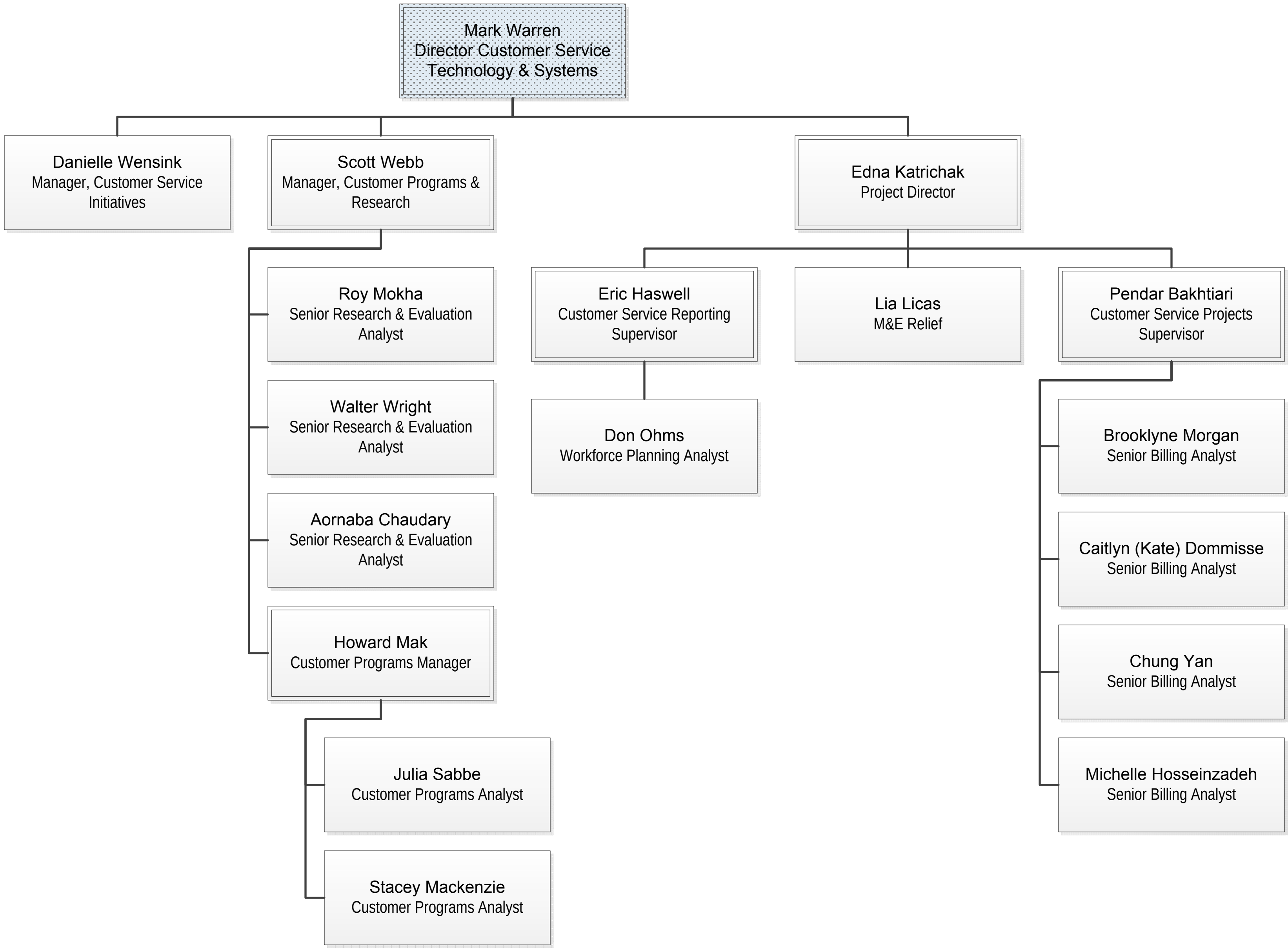
As at June 30, 2013

- **David Slight** – Manager, Payments & Collections
  - **Mark Hynes** – Contact Centre Team Manager
    - Sheraaz Khan – Senior Customer Service Representative
    - Jordan Campbell – Senior Customer Service Representative
    - Carly Paul – Senior Customer Service Representative
    - Gurvinder Chima – Customer Service Representative
    - Samantha Dyer – Senior Customer Service Representative
    - Denis Salak – Customer Service Leader
    - Sherman (Shun Wai) Kan – Senior Customer Service Representative
    - Brenda Eggett – Senior Customer Service Representative
    - Tajinder Kang – Senior Customer Service Representative
    - Kelly Bocking – Senior Customer Service Representative
    - Everlove Mondano – Senior Customer Service Representative
    - Avinesh Kumar – Senior Customer Service Representative
  - **Jim Doyle** – Contact Centre Team Manager
    - Judith Sterne – Senior Customer Service Representative
    - Susan Coleman – Customer Service Leader
    - Billy Wai Kin Ng – Senior Customer Service Representative
    - Taskeen Aysha – Senior Customer Service Representative
    - Gino Pastorino – Senior Customer Service Representative
    - Sheri Sandhu – Customer Service Leader
    - Leona Schmidt – Senior Customer Service Representative
    - Mahendra Patel – Senior Customer Service Representative
    - Bernadette Jacqueline Diy – Senior Customer Service Representative
    - Janie McDougall – Senior Customer Service Representative
    - Carol Curran – Senior Customer Service Representative
    - Maria Carolina Barrera – Senior Customer Service Representative
    - Zohrana Bashir – Senior Customer Service Representative

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Nicole Vandenakker
Senior Manager, Billing Operations

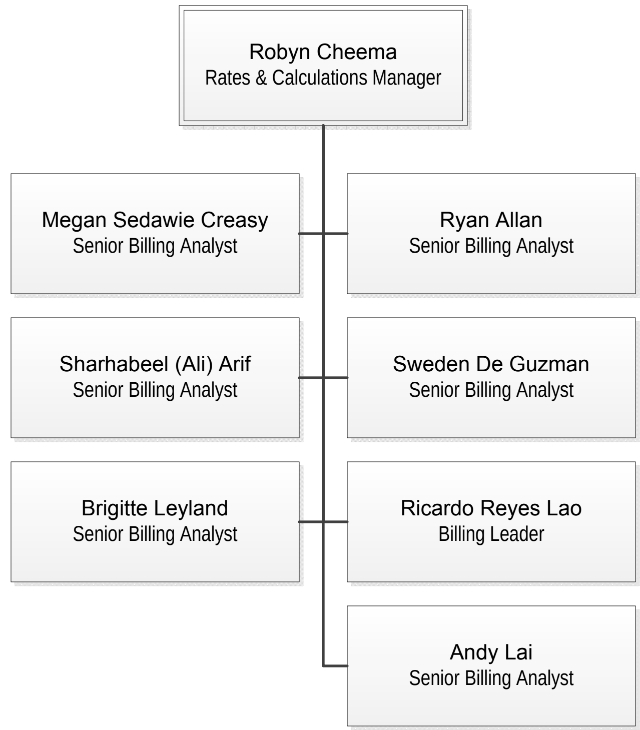
- **Gloria Manca** — Customer Service Confidential Assistant

- **Nicole Gill** — Manager, Billing Production
  - **Robyn Cheema** — Rates & Calculations Manager (See page 83)
  - **Alison Hunter** — Billing Exceptions Manager (See page 84)
  - **Kristy Selinger** — Billing Exceptions Manager (See page 85)
- **Debbie Kondro** — Mgr, Complex Billing & Meter Reader Supp
  - **Kris Feeney** — Meter Reading Coordinator
  - **Matthew Downey** — Complex Billing Leader
  - **Jeffrey Gill** — Meter Reading Coordinator
  - **Tanja Percival** — Complex Billing Leader
  - **David Torrance** — Meter Reading Coordinator
  - **Vardip Sandhu** — Senior Billing Analyst
  - **Danel Mireau** — Meter Reading Coordinator
  - **Diane Lee-Hawker** — Senior Billing Analyst
  - **Andi Warner** — Senior Billing Analyst
  - **Alvin Lau** — Senior Billing Analyst
  - **Myra McIntosh** — Senior Billing Analyst
  - **Malissa McDade** — Senior Billing Analyst
- **Uschi Hopping** — Manager, Industrial Billing
  - **Robert Franks** — Industrial Billing Representative
  - **Ricardo Caicedo** — Industrial Billing Representative
  - **Carley Cowan** — Industrial Billing Representative
- **Erica Gugay** — Customer Service Process Analyst
- **Tracey Thomson** — Manager, Billing Support
  - **Suzette Joe** — Billing Analyst
  - **Caitlin Rowe-Sleeman** — Billing Analyst
  - **Angela Roberts** — Billing Analyst
  - **Samantha Curpen** — Billing Leader
  - **Natasha Kaloya** — Billing Analyst
  - **Ting Ting Yao** — Billing Analyst
  - **Meenakshy Suryanarayanan** — Billing Analyst

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- Alison Hunter
  Billing Exceptions Manager
  - Matthew Johnston
    Complex Billing Leader
  - Amandeep Kaur
    Billing Analyst
  - Joanna McInnes
    Billing Analyst
  - Stephanie Kemash
    Billing Analyst
  - Nermina Karic
    Billing Analyst
  - Samantha Kosor
    Billing Analyst
  - Mathew Hung
    Billing Analyst
  - Stela Kordic
    Billing Analyst
  - Frederick Boudrias
    Senior Billing Analyst

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

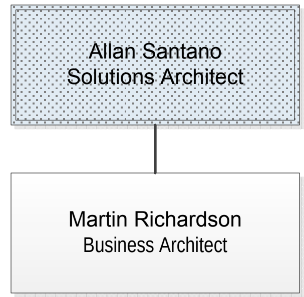
Kristy Selinger
Billing Exceptions Manager

- Riga Multani – Senior Billing Analyst
- Inika Wong – Senior Billing Analyst
- Richard Mbanefo – Senior Billing Analyst
- Shelby Mitchell – Senior Billing Analyst
- Lior Sitkovsky – Senior Billing Analyst
- Sara Johnston – Senior Billing Analyst
- Neil Keaney – Senior Billing Analyst
- Svetlana Runevska-Noveska – Senior Billing Analyst
- Ryan White – Senior Billing Analyst
- Lauren Collier – Senior Billing Analyst
- Yuka Rose – Senior Billing Analyst

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Robert Croston
Manager, IT PMO

Cristina Lin
Relief Clerk

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Darwin Anderson** — Infrastructure Manager
  - **Christopher Ellis** — Infrastructure Planning Specialist
  - **Jerzy (Jurek) Plona** — Infrastructure Planning Specialist
  - **Brent Peterson** — Infrastructure Planning Specialist

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

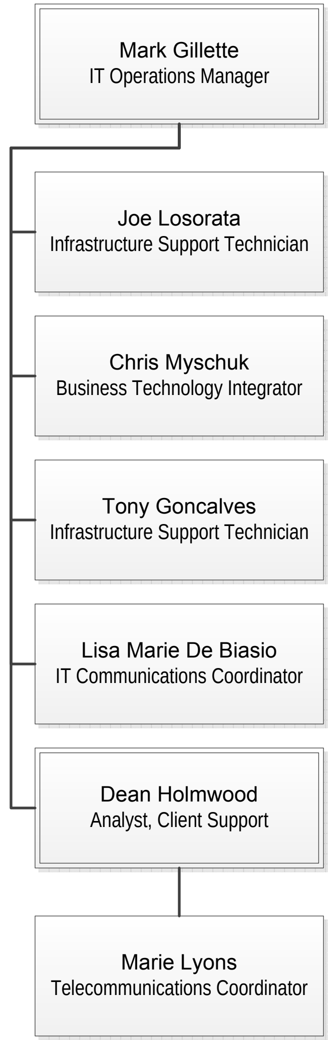
As at June 30, 2013

- **Frans Luit** – Manager, Enterprise Applications
  - **Jennifer Ma** – IT Enterprise Application Manager
    - Andrew Gregory – Operations Process Lead
    - Anne Siopongco – Operations Process Lead
    - Michael Pratt – Operations Process Lead
    - Amar Sidhu – M&E Relief
  - **Kirit Pranjivan** – IT Enterprise Application Manager
    - Simon Norman – SAP Analyst - Supply Chain
  - **Pauline Hum** – IT Enterprise Application Manager
    - Trevor Price – SAP Analyst - HR
    - Doris Butula – SAP Analyst - HR
    - Scott Hope – SAP Analyst - HR
  - **Adrian Trollip** – Enterprise Development Manager
    - Shirley Garfias – Enterprise Development Lead
    - Bentz Lee – Enterprise Development Lead
    - Drew Ehlert – Enterprise Development Lead
    - Carol Saito – Enterprise Development Lead
    - Nasir Iqbal – Enterprise Development Lead
  - **William Chen** – SAP Technical Support Manager
    - SaeEun (Kate) Kwon – SAP Basis Lead
    - Kenneth Lam – SAP Security Lead
    - Shannon Stouffers – SAP Basis Lead
    - Albert Tam – SAP Basis Lead
    - Michael Fong – SAP Security Lead
  - **Josephine Hope** – IT Enterprise Application Manager
    - Renett Chan – Operations Process Lead
    - Simon Lamb – Operations Process Lead
    - Andrew Foo – Operations Process Lead
    - Tommy Yee – Operations Process Lead
  - **Vickie Otway** – IT Enterprise Application Manager
    - David Gladwell – SAP Analyst - Finance
    - Cynthia Givens – SAP Analyst - Finance
    - Kevin Gregory – SAP Analyst - Finance
    - Samantha Dascenzo – SAP Analyst - Finance
  - **Jason Dais** – IT Enterprise Application Manager
    - Andy Powell – Operations Process Lead
    - Pam Beaudin – Operations Process Lead

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- **Raveena Nat**
  Business Systems Planning Manager
  - **Annette Tipper**
    Business Systems Solutions Specialist
  - **Una Chan**
    Business Systems Solutions Specialist

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

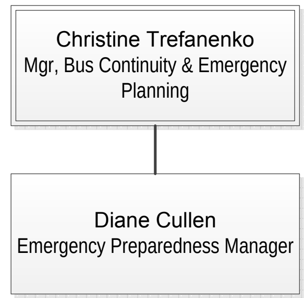
As at June 30, 2013

- **Andrew Kwok** – Application Support & Delivery Manager
  - **Ray Chiu** – Data Resource Management Manager
    - Alan Wong – Database Analyst
    - Sow-Yuen Brown – Data Analyst
    - David Shyong – Business Warehouse Technical Lead
    - Saeid Asgari-Marani – Data Analyst
    - Anatol Harasym – Business Warehouse Technical Lead
  - **Cheri Alston** – Web Services Manager
    - Terry Roy – Web Specialist
    - Jessica Hewitt – Technical Standards Writer
    - Brendan Peterson – Forms Analyst/Designer
    - Kristy Hensrud – Web Specialist
    - Henry Yu – Web Specialist
  - **Garry Ruthe** – Application Support Manager
    - Mark Berger – Application Support Analyst
    - Narmin Hemnani – Application Support Analyst
    - Mark Hing – GIS Support Analyst
    - George Thomas – Contact Centre Support Analyst
    - Andre Beausejour – Contact Centre Support Analyst
    - Sandeep Chima – Application Support Analyst
    - Murali Nair – GIS Support Analyst
    - Brian Earle – Application Support Analyst
    - Farid Mashhadi – Data Integration Analyst
    - Samy Shenouda – Application Support Analyst
  - **Sherman Woo** – Application Support Manager

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

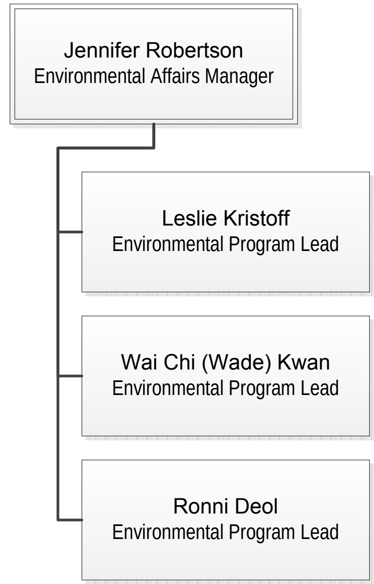
As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Niall Berry
OH&S & Corporate Security Manager

Brenda Mitchell
Health & Safety Advisor

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

- Roger Dall'Antonia, Vice President Strategic Planning , Corporate Development & Regulatory
  - Shawn Hill, Director, Regulatory Affairs (EP&CS)
    - Cari Kobialko, Regulatory Policy Manager
    - Samuel Nyabando, Regulatory Policy Manager
    - Negar Ghavami, Regulatory Policy Manager
  - Diane Roy, Director, Regulatory Affairs (Gas)
    - Edward Moore, Cost of Service Manager
    - Jeff May, Cost of Service Manager
    - Ravinder Purewal, Cost of Service Manager
    - Richard Gosselin, Cost of Service Manager
    - Rouzbeh Mehrazma, Regulatory Analyst
    - Ilva Bevacqua, Manager, Regulatory Compliance & Admin.
      - Robin Jenkins, Regulatory Governance Coordinator
      - Colleen Gravel, Tariff and Rate Design Specialist
      - Janice Barkey, Regulatory Governance Coordinator
      - Brandi Paulson, Regulatory Affairs Assistant

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

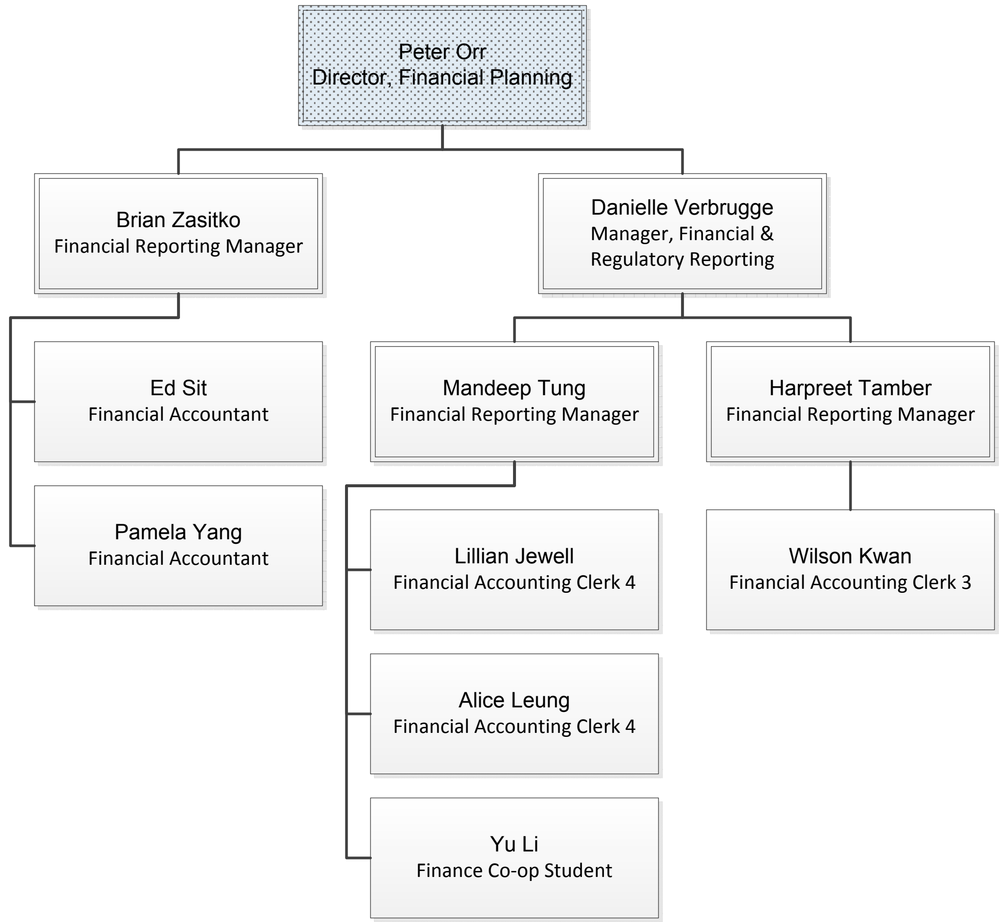
As at June 30, 2013

- **Alan North** – Manager, Planning & Design
  - Bimal (Jonny) Singh – Commercial Customer Service Technician
  - Timo Pirhonen – Commercial Customer Service Technician
  - Keith Kennedy – Pressure & Measurement Technician
  - David Brewer – Pressure & Measurement Apprentice
  - John Humeny – Commercial Customer Service Technician
  - Jim Jensen – Commercial Customer Service Technician
  - Louis Leung – Pressure & Measurement Apprentice
  - Gary George – Pressure & Measurement Apprentice

NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013



NOT a FEI employee

FORTISBC ENERGY INC (FEI)

As at June 30, 2013

Lisa Elliott
M&E Relief
(See page 99)

- **Krista Kobitzsch** – Operations Process Analyst 1
- **Steven Hoffmann** – Operations Process Analyst 2
- **Darla Merrick** – Operations Process Analyst 2
- **Carmen Barbour** – Operations Process Analyst 1
- **Kimi Miki** – Operations Process Analyst 3
- **Susanna Tateyama** – Operations Process Analyst 2
- **Lilibeth Calinisan** – Operations Process Analyst 1

NOT a FEI employee

Attachment 75.2

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 77.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 78.1

FILED CONFIDENTIALLY

Attachment 78.1

HayGroup

Terasen Gas

VP & GM Terasen Energy Services

904 Hay Points

Data are as of May 1, 2008

Commercial Industiral Organizations excluding Fortis companies (Executive Market) (N = 74)

	Design Compensation		Actual Compensation	
	Base Salary Policy	Total Cash Design	Base Salary	Total Cash
P90	175,586	225,081	183,219	247,626
P75	156,666	198,412	160,165	205,511
P50 (Median)	**135,457**	**169,795**	**140,364**	**172,588**
P25	125,421	151,807	125,053	148,065
P10	112,796	141,457	111,255	127,974
Average	142,199	177,859	144,493	180,391

Attachment 78.2.1

2012 Canadian Commercial Industrial Market (n=275)

3M Canada Company
A&W Food Services of Canada Inc.
ALS Canada Ltd.
AMEC Americas Limited
ATCO I-Tek
Abbott Laboratories, Limited
Acuity Brands
Agfa Healthcare Canada
Agfa Inc.
Ainsworth Engineered Canada L. P.
Air Products Canada Ltd.
Akzo Nobel Canada Inc.
Alamos Gold Inc.
Alberta-Pacific Forest Industries Inc.
Alcon Canada Inc.
Aluminerie Alouette Inc.
Amgen Canada Inc.
Amway Canada Corporation
ArcelorMittal Canada
ArcelorMittal Canada Contrecoeur-Ouest Inc.
ArcelorMittal Canada Hamilton
ArcelorMittal Canada Saint-Patrick
ArcelorMittal Dofasco Inc.
ArcelorMittal Mines Canada
ArcelorMittal Tubular Products - Automotive Division
Arrow Transportation Systems Inc.
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
Atlantic Packaging Products Ltd.
Atlantic Poultry Incorporated
Atotech Canada Ltd.
BASF Canada Inc.
BHP Billiton - Ekati Diamond Mines
BHP Billiton Canada Inc.
BIC Graphic Canada
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barilla
Barrick Gold Corporation
Basell Canada Inc.
Baxter Corporation
The Bay
Bayer Inc.
Bekaert Canada
Belden CDT (Canada) Inc.
Bericap North America Inc.
Blue Mountain Resorts Limited
Boehringer Ingelheim (Canada) Ltd.
Bombardier Transportation Canada Inc.
Brink's Canada Limited
Bristol-Myers Squibb Canada Co.
Broan-NuTone Canada Inc.
Bruce Power L.P.
CAE Inc.
CGGVeritas
CHEP Canada Inc.
CKF Inc.
CNH America, LLC.
Cabot Canada Ltd.
Campbell Company of Canada
Canadelle Inc.
Canadian Forest Products Ltd.
Canadian National Railway Company
Canadian Pacific Railway
Canexus Corporation
Canfor Pulp Limited Partnership
CannAmm Occupational Testing Services
Canon Canada Inc.
Canpotex Limited
Cargill Limited
Catalyst Paper Corporation
Caterpillar Logistics Services Canada Limited
Caterpillar of Canada Corporation
Caterpillar Tunneling Canada Corporation
Centerra Gold Inc.

2012 Canadian Commercial Industrial Market (n=275)cont'd

Christie Digital Systems Inc.
Chubb Edwards
The Churchill Corporation
Co-op Atlantic
Compass Group Canada
Coty Canada
Country Ribbon Inc.
DP World Canada
DSM Nutritional Products Canada Inc.
Danfoss Inc.
De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
Detour Gold Corporation
Direct Energy Marketing Ltd.
Dow Chemical Canada Inc.
Dr. Oetker Ltd.
Dynaplast Extruco Inc.
EFW Radiology
E.I. du Pont Canada Company
EMD Serono Canada Inc.
ERCO Worldwide
EWOS Canada Ltd.
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.

Essar Steel Algoma Inc.
Finning Canada
Finning International
Fisher & Paykel Healthcare Inc.
G4S Cash Services (Canada) Ltd.
Gates Canada Inc.
General Kinetics Engineering Corporation
Gerdau Long Steel North America
GlaxoSmithKline Inc.
Goldcorp Inc.
Golf Town
Graham & Brown
Grand & Toy
Griffith Laboratories Limited
Henkel Canada Corporation
Henry Schein Canada
Hilti (Canada) Ltd.
Hobart Food Equipment Services Canada
Hoffmann-La Roche Ltd.
Home Outfitters
HudBay Minerals Inc.
Hudson's Bay Company
HumanWare
Hunter Dickinson Inc.
Huntsman Polyurethane
INEOS Canada Partnership

INVISTA (Canada) Company
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
Janssen Inc.
John Deere Limited Canada
Johnson Matthey Ltd.
K+S Potash Canada
KGHM International Ltd.
K.I. Pembroke
KPMG MSLP
Kellogg Canada Inc.
Kemira Chemicals Canada Inc.
Kennametal Ltd.
Kimberly-Clark Corporation
Kinross Gold Corporation
Kongsberg Automotive
Kruger Products
LANXESS Inc.
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
Lantic Inc. - Rogers Sugar Division
Lego Systems, Inc.
Lehigh Hanson Materials Limited
Leo Pharma

2012 Canadian Commercial Industrial Market (n=275)cont'd

LifeLabs
Linamar
Loblaw Companies Limited
Lotus Bakeries
Lowe's Companies, Inc.
Lundin Mining Corporation
MDA
MERSEN Canada Dn Ltd.
MERSEN Canada Toronto Inc.
Maidstone Bakeries Co.
Mainstream Canada Ltd.
McCoy Corporation
McElhanney Consulting Services Ltd.
The McElhanney Group Ltd.
McElhanney Land Surveys Ltd.
Merz Pharma Canada
Methanex Corporation
Michelin North America (Canada) Inc.
Minas Basin Pulp & Power Co. Ltd.
The Minto Group
Mitsubishi Canada Limited
Montship Inc.
Morneau Shepell Inc.
The Mosaic Company
Navtech Systems Support Inc.
North American Palladium Ltd.
North Atlantic Refining
Northern Pulp Nova Scotia Corp.
Novartis Pharmaceuticals Canada Inc.
Novo Nordisk Canada
Omicron
L'Oréal Canada Inc.
Otis Spunkmeyer Canada Limited
Outotec (Canada) Ltd.
OxyVinyls Canada Inc.
PPG Canada Inc.
PPG Canada Inc. - Fine Chemicals Division
PPG Canada Inc. - Industrial Coatings Division
PPG Canada Inc. - Performance Glazing Division
Pan American Silver Corporation
Penske Truck Leasing
PepsiCo Canada
Phantom Mfg. (Int'l) Ltd.
Pharmascience Inc.
Philips Electronics Ltd.
Pioneer Hi-Bred Limited
Potash Corporation of Saskatchewan Inc.
Praxair Canada Inc.
Procter & Gamble Inc.
Purdue Pharma
Randstad Canada
Richemont Canada Inc.
Rio Tinto - Diavik Diamond Mines
Rio Tinto Iron Ore
Ritchie Bros. Auctioneers (Canada) Ltd.
Rolls-Royce Canada Ltd.
Rothmans, Benson & Hedges Inc.
Runge Limited
Russel Metals Inc.
SABIC Innovative Plastics Canada Incorporated
SEMAFO inc.
SNC-Lavalin Group Inc.
Saint-Gobain Abrasives Canada Inc.
Saint-Gobain Ceramic Materials Canada/Abrasive Materials
Sanofi Canada
Saskatchewan Roughrider Football Club
Schneider Electric
Sears Canada Inc.
The Shaw Group Limited
Sherritt Coal
Shiseido (Canada) Inc.
Shore Gold Inc.
Siegwerk Canada Inc.
Sika Canada Inc.
Silver Standard Resources Inc.

2012 Canadian Commercial Industrial Market (n=275)cont'd

Sleeman Breweries Ltd.
Société en Commandite Tafisa Canada Inc.
Sofina Foods Inc.
Sonoco Canada Corporation
Sultran Ltd.
Suncor Energy Inc.
Syncrude Canada Ltd.
TELUS Communications Inc.
TVI Pacific, Inc.
Tait Electronics Ltd.
Takeda Canada Inc.
Taro Pharmaceuticals Inc.
Teck Resources Limited
Teck Resources Limited - Highland Valley Copper
Teck Resources Limited - Trail Operation
Teekay Corporation
Tembec Inc.
Teranet Inc.
Tetley Canada Inc.
Teva Canada Limited
Thompson Creek Metals Company
TimberWest Forest Corp.
Tolko Industries Ltd.
TomTom International
Toromont CAT, A Division of Toromont Industries Ltd.
Toys "R" Us (Canada) Ltd.
Ultramar Ltée
uniPHARM Wholesale Drugs Ltd.
Uranium One Inc.
Vale Inco Limited
Vallourec Tubes Canada Inc.
VAM Canada
Viterra Inc.
Votorantim Cement North America
VPL Enterprises Ltd.
VWR International
W.E.T. Automotive Systems Ltd.
Wal-Mart Canada Corp.
WD-40 Products Canada Ltd.
Wescast Industries Inc.
West Fraser Timber Co. Ltd.
Winners Merchants International L.P.
Xstrata Copper Canada
Xstrata Nickel Canada
Xstrata Zinc Canada
Yara Belle Plaine Inc.
Yukon Zinc Corporation
Zellstoff Celgar Partnership Limited

Attachment 78.2.2

Hay Group Limited
121 King Street West
Suite 700
Toronto, ON M5H 3X7
Canada

tel +1.416.868.1371
fax +1.416.868.6871

www.haygroup.com/ca

June 29, 2011

Ms. Andrea Best
Director, Employee Services
FortisBC
Suite 100
1975 Springfield Road
Kelowna, BC
V1Y 7V7

Dear Ms. Best,

Re: Fortis Energy ("FEU") 2012/2013 Revenue Requirements Application Intervener Request

We have been asked to provide information to assist FEU in responding to the following Intervener Request for your 2012/2013 Revenue Requirements Application:

"9.2 On page 37 it is stated that "[a]s a general policy, FEU establish base and incentive compensation targets so as to compensate executives at a level generally equivalent to the median level of a broad reference group of approximately 200 Canadian commercial industrial companies." Please provide complete details with respect to the composition of the reference group and why the particular companies are appropriate and were selected for the group, the reference group's median levels of base and incentive compensation, a copy of the most recent compensation survey (Hay Group's Paynet Database), and support for the claim that FEU compensation targets are at the median level of the reference group."

This letter includes the following:

1. A complete list of the Canadian Commercial Industrial Companies and why they are appropriate comparators
2. An explanation of the Hay Guide-Chart and Profile Method of Job Evaluation^{SM} and the median levels of base salary and incentive compensation for the Commercial Industrial group
3. A summary of the most recent Hay Group compensation analysis that benchmarks pay for FEU

Canadian Commercial Industrial Companies

The executive compensation policy of FEU is to compensate executives at a level approximately at the median of the practice of the Canadian Commercial Industrial Market.

The Hay Group Canadian Commercial Industrial group consists of all publicly traded and privately owned companies in Canada, excluding financial organizations. This comparator group represents a broad spectrum of Canadian industrial organizations with which FEU competes for executive talent. There are 295 companies in this group. For a complete list of these companies please see Attachment A.

FEU, Hay Group Job Evaluation and Commercial Industrial Market Median Base Salary and Target Bonus

The Hay Group Guide Chart-Profile Method of Job Evaluation℠ is used by thousands of organizations in Canada and worldwide to understand and compare jobs from clerical/trade to management/professional and executive level positions.

In essence, the comparison is made between different aspects of total job content, defined as Know-How, Problem Solving and Accountability. The sum of these measures, expressed in job evaluation "points", represents the value of the whole job (Attachment B).

All FEU executives have been evaluated using the Hay Group method and compared to jobs of a similar content ("Hay Points") in the Hay Group Commercial Industrial database for compensation benchmarking. In contrast to a job title match, this methodology enables FEU to compare to a more robust sample including many companies that are bigger or smaller but still compete with FEU for executive talent. The following table sets out the market median levels of compensation.

FEU Position	2011 Market Actual Salary Median*	2011 Market Target Bonus % Median
President & CEO	$493,100	54%
EVP & VPs**	$205,900 - $273,900	30% - 39%

*Commercial Industrial market data as of 2010 has been projected 2.2% to reflect anticipated 2011 compensation levels.

**Based on the market medians for 7 EVP and VPs.

Please see Attachment C for a summary of the Base Salary and Target Bonus analysis.

I will be happy to answer any further questions that may arise.

Sincerely,
Hay Group Limited

Christopher A. Chen, LLB
National Director
Executive Compensation

Attachment A – Commercial Industrial Comparator Group (N = 295)

A&W Food Services of Canada Inc.
ACA Co-operative Limited
AV Nackawic Inc.
Abbott Laboratories, Limited
Abbott Products Inc.
Agfa Healthcare Canada
Agfa Inc.
Agnico-Eagle Mines Limited
Ainsworth Engineered Canada L. P.
Air New Zealand
Air Products Canada Ltd.
Aker Chemetics
Akzo Nobel Canada Inc.
Alberta-Pacific Forest Industries Inc.
Alcon Canada Inc.
Allergan Canada Inc.
ALS Laboratory Group
AltaSteel Ltd.
Aluminerie Alouette Inc.
Amcor Limited
Amgen Canada Inc.
Amway Canada Corporation
Andrew Peller Limited
Anglo American Exploration (Canada) Ltd.
Apotex Inc.
ArcelorMittal Canada
ArcelorMittal Canada Contrecoeur-Ouest Inc.
ArcelorMittal Canada Hamilton
ArcelorMittal Canada Lachine
ArcelorMittal Canada Saint-Patrick
ArcelorMittal Dofasco Inc.
ArcelorMittal Mines Canada
ArcelorMittal P&T
ArcelorMittal Tubular Products - Automotive Division
Arkema Canada Inc.
Arrow Transportation Systems Inc.
Ashland Distribution
Ashland Global Chemicals
Ashland Performance Materials
Ashland Water Technologies
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
Atlantic Packaging Products Ltd.
Atotech Canada Ltd.
Axcan Pharma Inc.
BASF Canada Inc.
BHP Billiton - Ekati Diamond Mines
BIC Graphic Canada
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barrick Gold Corporation
Baxter Corporation
The Bay
Bayer Inc.
The Beer Store
Beiersdorf Canada Inc.
Bekaert Canada
Belden CDT (Canada) Inc.
Bericap North America Inc.
bioMérieux Canada Inc.
Biovail Corporation
Boehringer Ingelheim (Canada) Ltd.
Bombardier Transportation Canada Inc.
Brink's Canada Limited
Bristol-Myers Squibb Canada Co.
Bronswerk Group
Bruce Power
CHEP Canada
CKF Inc.
CNH America, LLC.
Cabot Canada Ltd.
Cadbury North America
Campbell Company of Canada
Canada Safeway Limited
Canadelle Inc.
Canadian Forest Products Ltd.
Canadian National Railway Company
Canadian Pacific Railway
Canexus Limited
Canfor Pulp Limited Partnership
Canpotex Limited
Cargill Limited
Caterpillar of Canada Corporation
Centerra Gold Inc.
Chubb Edwards
The Churchill Corporation
Co-op Atlantic
Coca-Cola Bottling Company

Cognis Canada Corporation
Compass Group Canada
Cooper B-Line
Cooper Bussmann
Cooper Crouse Hinds
Cooper Hand Tools
Cooper Industries (Canada) Inc.
Cooper Lighting
Cooper Power Systems
Cooper Power Tools
Cooper Wiring Devices
Corby Distilleries Limited
Country Ribbon Inc.
Covance (Canada) Inc.
Cytec Canada Inc.
DENSO Manufacturing Canada, Inc.
DSM Nutritional Products Canada Inc.
Daishowa-Marubeni International Ltd.
Danfoss Inc.
Danone Canada Inc.
Davis + Henderson
De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
Dow Chemical Canada Inc.
Dow Corning Canada Inc.
Dr Pepper Snapple Group
Dundee Precious Metals
EFW Radiology
E.I. du Pont Canada Company
EWOS Canada Ltd.
Eaton Corporation
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.
Enbridge Gas Distribution Inc.
Essar Steel Algoma Inc.
Evonik Degussa Canada Inc.
FANUC CNC AMERICA Corporation
FMC of Canada, Ltd.
Ferrero Canada Limited Commercial Division
Ferrero Canada Limited Industrial Division
Finning (Canada)
Finning International Inc.
Fisher & Paykel Healthcare Inc.
FundSERV Inc.
G4S Cash Services (Canada) Ltd.
GDF SUEZ Energy North America, Inc.
Galderma Canada Inc.
Gates Canada Inc.
General Kinetics Engineering Corporation
GlaxoSmithKline Inc.
Goldcorp Inc.
Graceway Pharmaceuticals
Grand & Toy
Griffith Laboratories Limited
Group SEB Canada Inc.
Gulf Chemical Canada
HDS Retail North America
H. H. Angus & Associates Limited
H.J. Heinz Company of Canada Ltd.
Hecla Mining Company
Henkel Canada Corporation
Hilti (Canada) Ltd.
Hobart Food Equipment Services Canada
Hoffmann-La Roche Ltd.
Hudson's Bay Company
HumanWare
Huntsman Polyurethane
IAMGOLD Corporation
INEOS Canada Partnership
INVISTA (Canada) Company
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
Interquisa Canada
J. Ennis Fabrics Ltd.
J. H. Ryder Machinery Limited
JTI-Macdonald Corp.
JYSK CANADA
John Deere Limited Canada
Johnson Matthey Ltd.
Katz Group Canada Ltd.
Kellogg Canada Inc.
Kennametal Ltd.
Kinross Gold Corporation
Kongsberg Automotive
Kruger Products
LANXESS Inc.
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
Lehigh Hanson
Levi Strauss & Co. (Canada) Inc.
Lilydale Inc.

MDA
MDS Nordion
MMG Resources Inc.
Mainstream Canada Ltd.
McCormick Canada Co.
McElhanney Consulting Services Ltd.
The McElhanney Group Ltd.
McElhanney Land Surveys Ltd.
Meridian Lightweight Technologies Inc.
Methanex Corporation
Michelin North America (Canada) Inc.
Mitsubishi Canada Limited
Montship Inc.
The Mosaic Company
Mother Parkers Tea & Coffee Inc.
Mustang Survival Corp.
Mylan Pharmaceuticals ULC
NOVA Chemicals Corporation
Neopost Canada
Nestlé Canada Inc.
New Horizon System Solutions LP
Newmont Mining Corporation of Canada Limited
Northern Pulp Nova Scotia Corp.
Nova Scotia Power Inc.
Novartis Pharmaceuticals Canada Inc.
Novo Nordisk Canada
Nycomed Canada Inc.
Oakrun Farm Bakery Ltd.
Octapharma Canada Inc.
Olin Chlor-Alkali Products
L'Oréal Canada Inc.
Osler, Hoskin & Harcourt, LLP
PPG Canada Inc.
PPG Canada Inc. - Fine Chemicals Division
PPG Canada Inc. - Industrial Coatings Division
PPG Canada Inc. - Performance Glazing Division
Pan American Silver Corporation
Patheon Inc.
Penske Truck Leasing
PepsiCo Canada
PERI Formwork Systems, Inc. Canada
Pfizer Canada Inc.
Phantom Mfg. (Int'l) Ltd.
Philips Electronics Ltd.
Pioneer Hi-Bred Limited
Poly-Drill Drilling Systems Ltd.
Potash Corporation of Saskatchewan Inc.
Praxair Canada Inc.
Puratos Canada Inc.
QIT-Fer et Titane Inc.
Randstad Canada
Reflex Instrument North America
Richemont Canada Inc.
Rio Tinto - Diavik Diamond Mines
Rio Tinto Iron Ore
Ritchie Bros. Auctioneers (Canada) Ltd.
Rogers Communications Inc.
Rothmans, Benson & Hedges Inc.
Royal Group, Inc.
Russel Metals Inc.
SMS Equipment Inc.
Saint-Gobain Abrasives Canada Inc.
Saint-Gobain Ceramic Materials Canada/Abrasive Materials
sanofi-aventis
Sapphire Technologies
Saskatchewan Roughrider Football Club
Schlumberger Oilfield Services
Schneider Electric
The Shaw Group Limited
Sherritt Coal
Sherritt International Corporation
Shore Gold Inc.
Sidel Canada Inc.
Siemens Canada Limited
Sonoco Canada Corporation
Sultran Ltd.
Suncor Energy Inc.
Takeda Pharmaceuticals North America, Inc.
Taro Pharmaceuticals Inc.
Teck Resources Limited
Teck Resources Limited - Highland Valley Copper
Teck Resources Limited - Trail Operation
Teekay Corporation
Tembec Inc.
Teranet Inc.
Thales Rail Signalling Solutions
Thompson Creek Metals Company
Thrifty Foods Inc.
TimberWest Forest Corp.
Timminco Limited
Tolko Industries Ltd.
TomTom International
Toromont CAT, A Division of Toromont Industries Ltd.
Total E&P Canada

Twin Rivers Paper Company
Ultramar Ltée
uniPHARM Wholesale Drugs Ltd.
Vale Inco Limited
Valeant Canada Limited
Valvoline
Vanguard Plastics Ltd.
Vicwest Income Fund
Viterra Inc.
Votorantim Cement North America
Wal-Mart Canada Corp.
Wescast Industries Inc.
West Fraser Timber Co. Ltd.
Winners Merchants International L.P.
Xstrata Copper Canada
Xstrata Nickel Canada
Xstrata Zinc Canada
Zellers
Zellstoff Celgar Partnership Limited

Attachment B – Job Evaluation

The Hay Group Guide Chart-Profile Method of Job Evaluation℠ was developed by Edward N. Hay in the early 1940's and has been modified over the years to reflect the changing needs of organizations. It is the most widely used process in the world for evaluating jobs. Two principles are fundamental to the Guide Chart-Profile method:

1. An understanding of the content of the job to be measured
2. The direct comparison of one job with another job to determine relative value

The method is based on Hay Group's long experience (over 50 years) with both private and public sector clients. Job evaluation is the systematic process for ranking jobs logically and fairly by comparing job against job or against a pre-determined scale to determine the relative importance of jobs to an organization

The evaluations are of jobs not people:

- Performance, Individual qualifications and seniority of the incumbent is not considered
- Potential or current pay of the incumbent is irrelevant
- The number of candidates available for a job or the dollar value the market puts on the job do not make the job any larger or smaller
- These factors are ignored during job evaluation. They are taken into account in the pay administration process

The Hay Group job evaluation methodology is based on three main factors:

- Know-How -- The total of all knowledge and skill required to do the job
- Problem Solving -- The amount and kind of thinking required such as analyzing, reasoning, evaluating, creating, and using judgment
- Accountability -- The opportunity the job has to bring about results to the organization

The comparison is made between different aspects of total job content, defined as Know-How, Problem Solving and Accountability. The sum of these measures, expressed in job evaluation “points”, represents the value of the whole job. The three elements are further refined and assessed, as follows:

Know-How: This factor measures the total of every kind of knowledge and skill, however acquired, needed for acceptable job performance. Three dimensions are considered:

- Practical procedures and knowledge, specialized techniques, and learned skills;
- Planning, coordinating, directing or controlling the activities and resources associated with an organizational unit or function; and
- Active, practicing, person-to-person skills in the area of human relationships

Problem Solving: This factor measures the thinking required in the job by considering two dimensions:

- the environment in which the thinking takes place; and
- the challenge presented by the thinking to be done

Accountability: This factor measures the relative degree to which the job, when performed competently, can affect the end results of the organization or a unit within the organization. The opportunity to contribute to an organization is reflected through dimensions, such as:

- the nature and degree of the decision-making or influence of the job;
- the unit or function most clearly affected by the job; and
- the nature of that effect

Attachment C – Commercial Industrial Base Salary and Target Bonus analysis for FEU

Position Title	Base Salary		STI Target %	
	Incumbent	2011 Commercial Industrial Median*	Incumbent	2011 Commercial Industrial Median
President & CEO	500,000	493,100	up to 50%	54%
EVP Finance, Regulatory and Energy Supply	306,000	273,900	up to 40%	39%
VP Energy Solutions & External Relations	267,700	251,000	up to 40%	39%
VP Energy Supply & Resource Development	251,000	239,900	up to 40%	38%
VP Operations (Natural Gas)	235,000	231,600	up to 35%	36%
VP Business Planning	230,000	221,000	up to 30%	33%
VP Finance & CFO, Treasurer	235,000	212,000	up to 30%	31%
VP Customer Service	205,900	205,900	up to 30%	30%

* Commercial Industrial data as of 2010 has been projected 2.2% to reflect anticipated 2011 compensation levels.

Attachment 78.3

FILED CONFIDENTIALLY

Attachment 79.1

FILED CONFIDENTIALLY

Attachment 79.2

Hay Group Limited
1140 West Pender Street
Suite 1390
Vancouver, BC V6E 4G1
Canada

tel +1.604.682.4269
fax +1.604.682.4405

www.haygroup.ca

September 27, 2010

Ms Jody Drope
Manager, Human Resources
Fortis BC Inc
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Dear Jody

As promised, this letter is to summarize the rationale for the selection of organizations in the market comparator group for Fortis BC and Terasen Gas. This recommendation is based on consultation with Fortis BC and Terasen Gas executives and HR representatives, as well as Hay Group's expertise and experience in external market comparison.

Fortis BC and Terasen Gas will have common long-term business goals and a common HR strategy going forward. They will also benefit from the ability to transfer talent from one organization to another. For these reasons, it is logical for Fortis BC and Terasen Gas to share a common compensation philosophy and to set salary ranges against a common comparator group. While this comparator group is likely to be similar to the comparator group used by Fortis Inc, the subsidiaries may compete for a different pool of talent than the parent and therefore may define the external market somewhat differently.

Comparator Group

The comparator group that we have recommended broadly represents Canadian industrial organizations that compete for a reasonably similar pool of talent. While individually each organization has its own specific pay policy and practice, together these organizations represent a stable, national comparator market for compensation. A complete list of these organizations is included as an appendix to this letter.

Selection Principles

This comparator group is a subset of the 539 organizations which have provided data to Hay Group's Canadian database. Since both Fortis BC and Terasen Gas recruit nationally for a variety of positions, a national comparator market is reasonable. Our approach was to start with this overall representation of the Canadian market and exclude various sectors whose talent pools are less relevant to Fortis BC. In our selection of organizations and industries, we were guided by the following general principles.

A stable comparator group

Generally speaking, larger comparator groups tend to be less susceptible to fluctuations caused by specific pay policies of any one organization. This is particularly important when the market data is being used to set base salary ranges. For specific pay decisions it can be better to analyze more specific geographic, or job related pay markets, but a broader comparator market for base salary ranges is more inclusive.

Exclusion by industry

Certain sub-sets of the Canadian marketplace compete for different pools of talent and have specific pay practices that are not relevant to either Fortis BC or Terasen Gas. We have excluded a number of industry groupings in order to develop a comparator group that was better aligned to the market where Fortis BC and Terasen Gas compete for talent. Industry groupings that were excluded include: financial services, pharmaceuticals, high technology, retail, and government.

Exclusion by geography

Upon review, it appeared that the Canadian database had a large number of Ontario-based industrial organizations that could potentially skew the data to represent more Eastern pay markets. While the national perspective is important for Fortis BC and Terasen Gas, both organizations are based in Western Canada therefore we were keen to avoid any inadvertent Eastern bias.

Industry orientation

Overall the comparator organizations include: all utilities in our database; natural resources companies including mining, forestry, and energy; engineering consulting; and industrial sector organizations based in Western Canada. The comparator group is primarily private sector, but includes relevant crown corporations and authorities such as provincial utilities and provincial safety authorities.

Utilities, natural resources companies, and organizations that recruit engineers will face similar recruiting and talent management challenges to Fortis BC and Terasen Gas. While revenues of resource-based organizations fluctuate with commodity prices, compensation policies are less volatile. Energy companies (and mining to a lesser extent) do have a reputation for high levels of compensation when responding to peaks in commodity prices. This is an important reality to recognize since Fortis BC and Terasen Gas will compete with these organizations for talent, particularly in the West. These pay practices are balanced out by forestry, industrial, manufacturing and broader public sector participants in the comparator group which help to provide an overall stable comparator market.

Jody, I hope that this letter helps to clarify the comparator group rationale for your future records. If you require any further information, please let me know.

Sincerely,

Tracy Bosch
Principal
Hay Group Limited

Attachment 79.5

FortisBC Inc.

Common Benefits Platform

Draft For Discussion

June 13, 2011

TOWERS WATSON

Table of Contents

Overview of Common Benefits Platform
Objectives

- In redesigning the pension and benefit programs, FortisBC established the following objectives:
  - Pension and savings programs should be excluded from the current review
  - A common platform of benefit programs for non-union employees should be established across FortisBC (FBC) and FortisBC Energy (FBCE)
  - The common platform should be positioned at the median relative to the FortisBC peer group, based on employer-provided values
    - — Active and retiree benefits should be positioned near the median relative to the peer group
    - — Paid-time off should be positioned at or below the median relative to the peer group

Active Benefit Program Design

Current Plans

- FBC and FBCE both offer flexible benefit programs for active employees
- The two flexible benefit programs are fundamentally similar, but with a variety of design differences:
  - FBCE provides Power Credits of 4% of pay to enable employees to buy back two weeks of vacation
  - FBCE also provides credits linked to certain options within the plan

Observations

- We observe the following:
  - FBCE's flex credits are linked to the price tags for the benefit Option 3
    - This approach limits the company's ability to manage future increases in benefit costs as the flex credit allocation will increase automatically as the cost of benefits increase
  - Paid time-off levels are low, but this may be mitigated by employees' appreciation of flexibility of additional 'earned' days off
    - FBC permits employees to earn 12 additional days off by working longer hours
    - FBCE permits employees to earn 17 additional days off by working longer hours

Proposed Plan

- We have developed four proposed plans for discussion:

Proposal	Flexible Benefits	Pension & Savings Program	Vacation & Holidays	Power Credit
A	FBCE	FBCE[1]	FBCE	4%
B	FBCE	FBCE[1]	FBCE	0%
C	FBCE	FBCE[1]	FBC	4%
D	FBCE	FBCE[1]	FBC	0%

Note:

1. The value of FBCE's pension and savings programs is within 0.3% of those of FBC. Accordingly, while we have reflected those of FBCE, the results presented in this report would differ very little were FBC's pension and savings programs included instead of the FBCE programs.

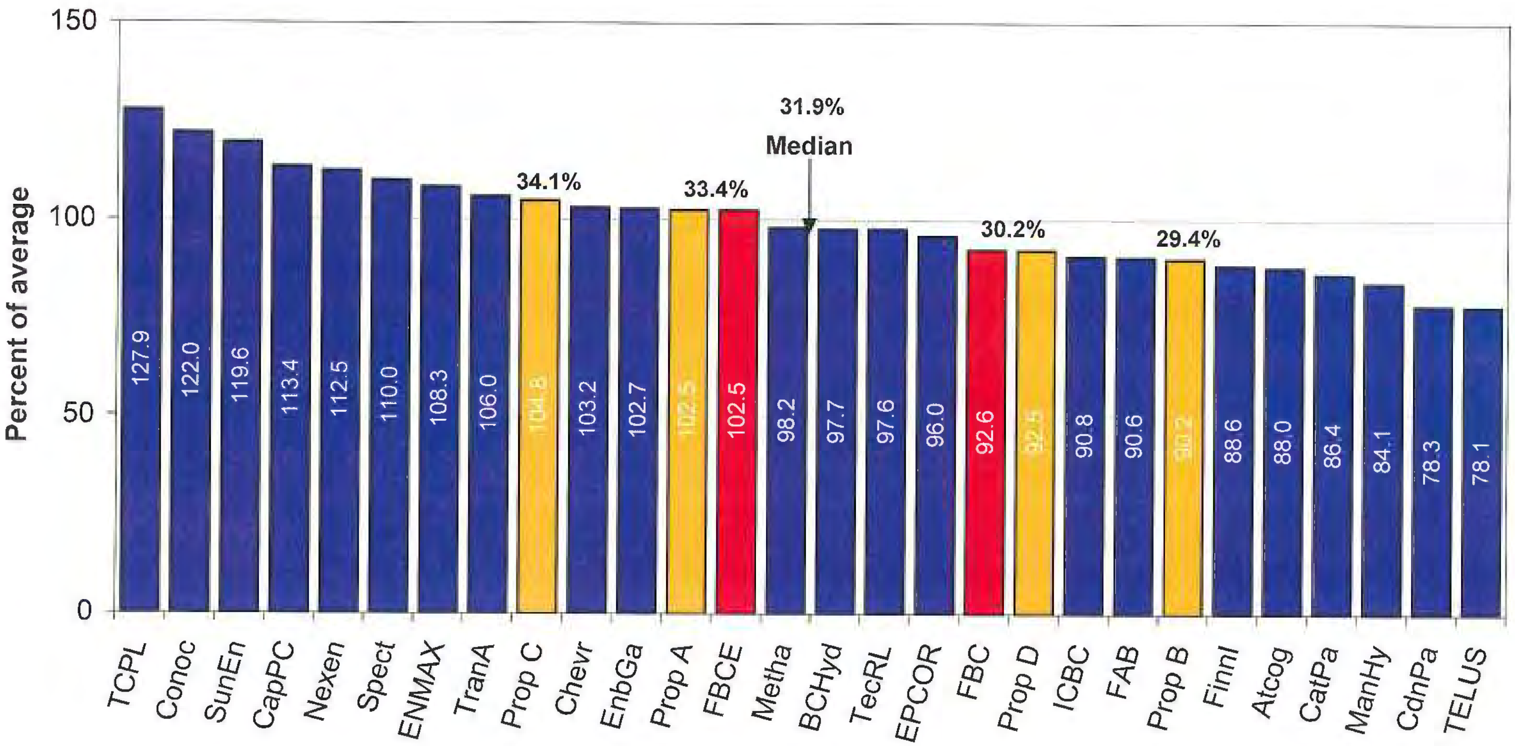
Benchmarking Analysis

Overview

- FortisBC has engaged Towers Watson to conduct a review of the competitiveness of the company's benefit programs
- The review includes the following benefit programs:
  - Disability programs (LTD, STD)
  - Life insurance
  - Extended health care and dental programs
  - Vacation, holidays and other paid time-off
- For reference, the pension and savings programs have also been included separately
- The results for FortisBC (FBC) and FortisBC Energy (FBCE) have been compared to those of a peer group of 22 companies (see Appendix I for peer group)
- The analysis has been undertaken using the methodology and assumptions described in Appendix II

All Pension, Benefit and Paid Time-off Programs

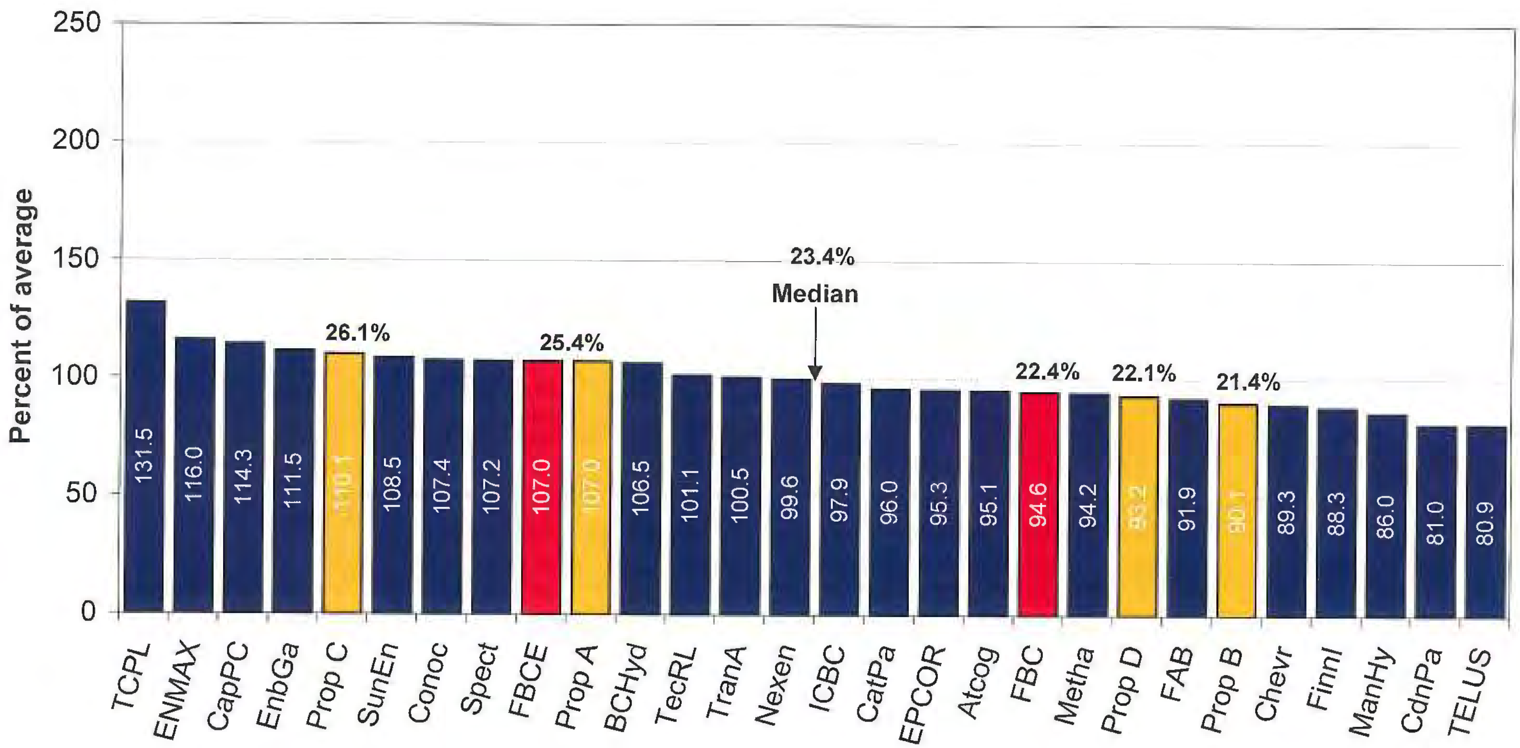
Employer-Provided Value – Excluding Employee Contributions



Average value: 32.6% of pay

Benefit & Paid Time-off Programs

Employer-Provided Value – Excluding Employee Contributions

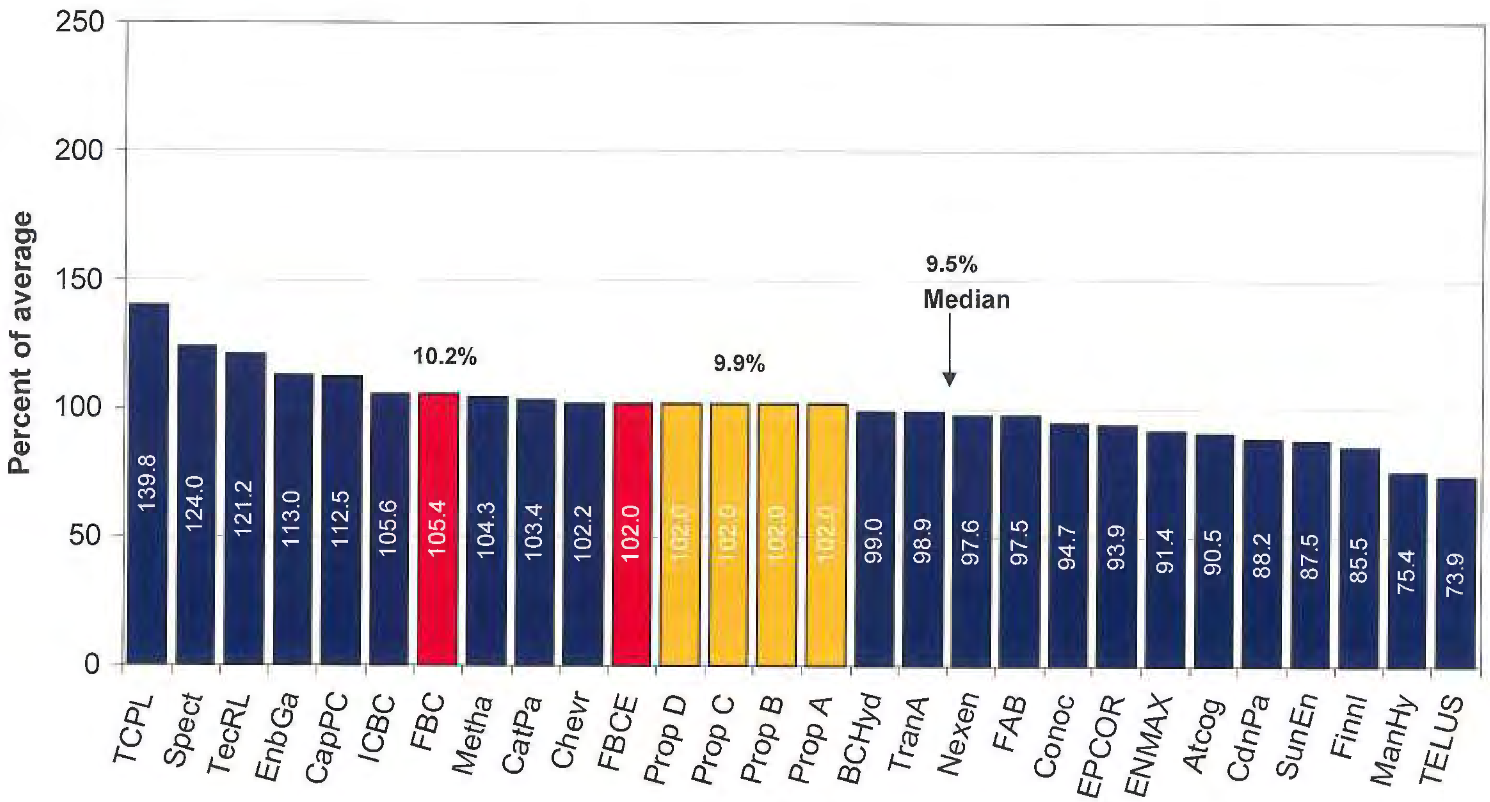


Average value: 23.7% of pay

V:\Terasen Gas Inc - 102216\11\RET\Benefits Benchmarking\Exec - Deliv\Common Benefits Platform_13Jun11_FINAL.ppt

Benefit Programs [1]

Employer-Provided Value – Excluding Employee Contributions



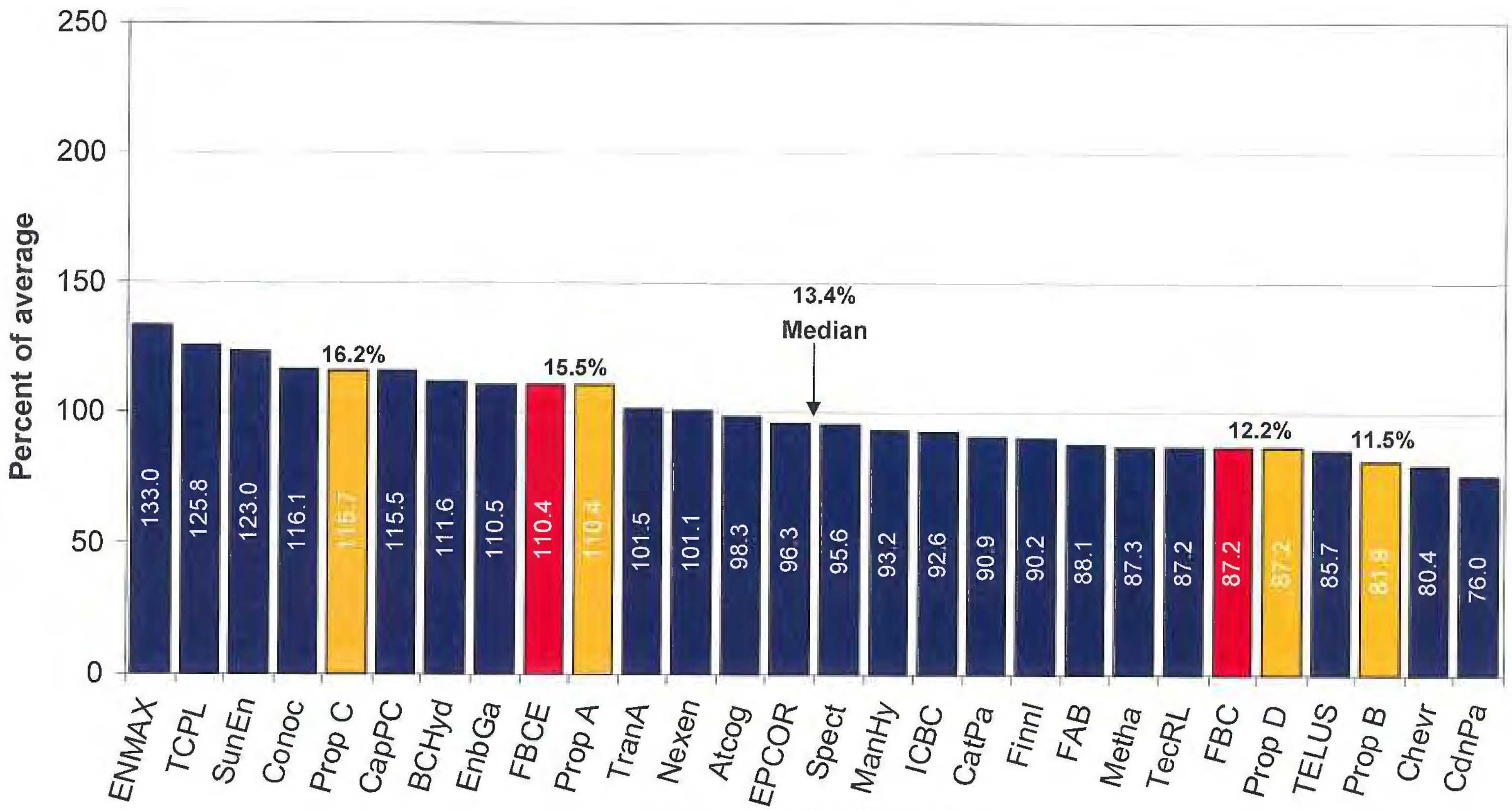
Average value: 9.7% of pay

Note:

1 The value of the 4% Power Credit has been included with the paid time-off programs and is therefore not reflected in the value of benefit programs shown on this page.

Paid Time Off [1]

Employer-Provided Value – Excluding Employee Contributions

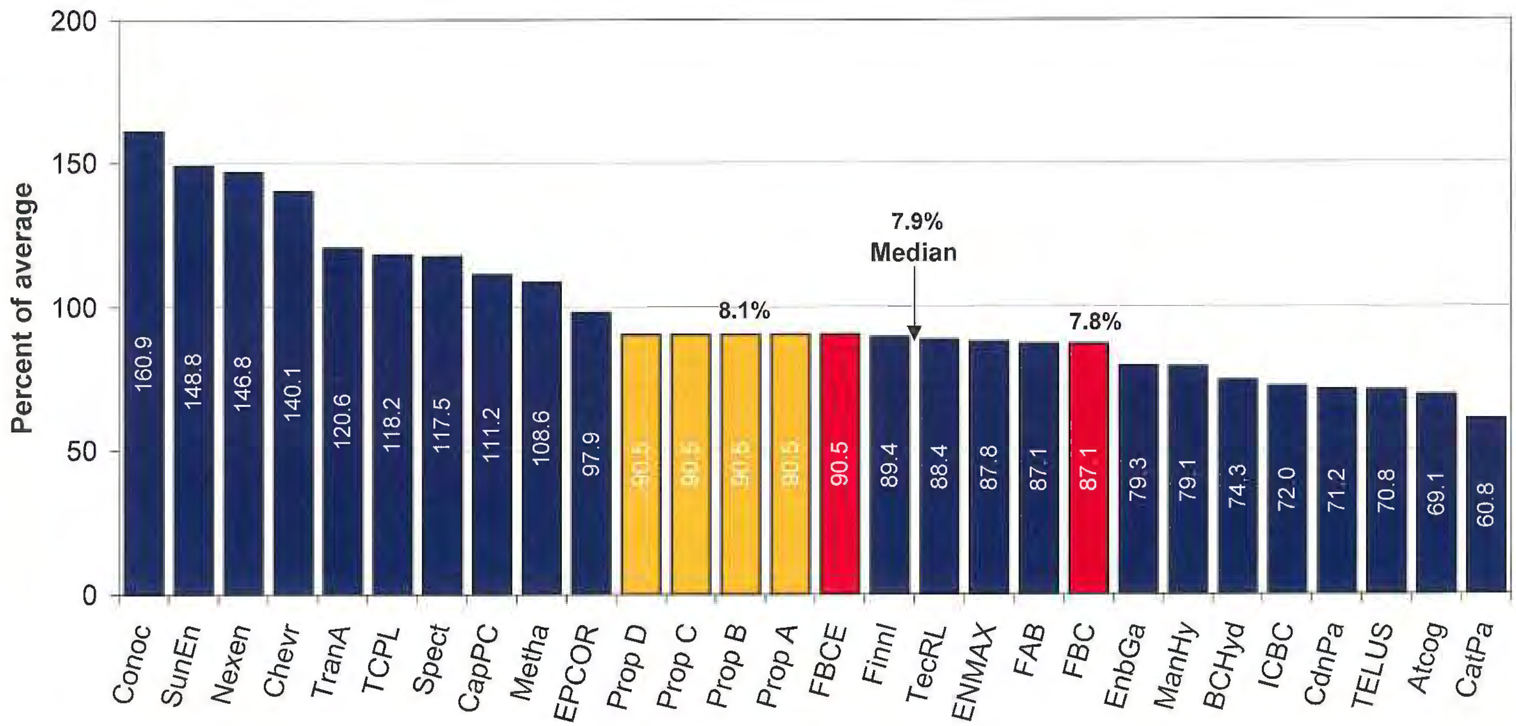


Note:

1 The value of the 4% Power Credit has been included with the paid time-off programs shown on this page.

Pension and Savings Programs

Employer-Provided Value – Excluding Employee Contributions



Average value: 8.9% of pay

Observations

Total Benefits & Paid Time-off Program

- The employer-provided value (excluding employee contributions) is generally used for purposes of competitive comparisons
  - The employer-provided value of the current benefits and paid time-off programs provided by FBCE are slightly above the median (approximately 107% of median)
  - The employer-provided value of the benefits and paid time-off programs provided by FBC are slightly below the median (approximately 94% of median)
  - The positioning of the employer-provided value of the proposed benefits and paid time-off programs depends on the 4% Power Credit:
    - If the 4% Power Credit is retained, the proposed program is above median (approximately 107% to 110% of median)
    - If the 4% Power Credit is eliminated, the proposed program is below median (approximately 90% to 93% of median)

Active Benefit Program Design

Flex Credit Formula

Current & Proposed

	FBC – Current	FBCE – Current	Proposed Plan
Summary	Full time employees receive: • 1.14% of pay, plus • $1,900 In addition, company will pay for provincial MSP premiums	Full time employees receive: • 1.43% of pay to pay for core LTD, basic and voluntary life insurance, plus • Flat amount of credits to pay for Option 3 for EHC and dental coverage and provincial MSP premiums, plus • Power Credits 4% of pay to buy back two weeks of vacation.	Full time employees receive: • TBD% of pay to pay for benefits, plus • Flat amount of credits to pay for provincial MSP premiums, plus • Power Credits of – Proposals A and C: 4% of pay to buy back two weeks of vacation, or – Proposals B and D: Nil.

Flex Credit Formula

Current & Proposed

	FBC – Current	FBCE - Current	Proposed Plan
	Detail – Full-time employee	Detail – Full-time employee	Detail – Full-time employee
Percent of pay	1.14% of pay to provide for LTD, basic and optional life insurance	1.43% of pay to provide for LTD, basic and voluntary life 4% of pay Power Credit	TBD% of pay, plus Power Credit of: ▪ Proposals A and C: 4% of pay ▪ Proposals B and D: Nil
Flat amount	$1,900 for EHC and dental	Based on family status	Based on family status
Flat amount by family status (rounded to nearest dollar)	**MSP** $684 single / $1,244 couple / $1,368 family if elect coverage,	**MSP** $684 single / $1,244 couple / $1,368 family if elect coverage, $300 if opt-out **EHC** $580 single / $930 couple / $1,350 family if elect coverage, $300 if opt-out **Dental** $600 single / $1,160 couple / $1,800 family if elect coverage, $300 if opt-out Company pays business travel accident (i.e., not a flex credit).	**MSP** $684 single / $1,244 couple / $1,368 family if elect coverage, $300 if opt-out **EHC** $580 single / $930 couple / $1,350 family if elect coverage, $300 if opt-out **Dental** $600 single / $1,160 couple / $1,800 family if elect coverage, $300 if opt-out Company pays business travel accident (i.e., not a flex credit).

Basic and Optional Life Insurance

Current & Proposed

Benefits	FBC – Current	FBCE - Current	Proposed Plan
Basic Life Insurance			
Benefit Schedule	1 x base earnings	1 x base earnings	1 x base earnings
Overall Maximum	$500,000	$900,000 (combined with Voluntary)	$900,000 (combined with Voluntary)
Employee Contribution	0%; company paid	0%; company paid	0%; company paid
Voluntary Life			
Benefit Schedule	N/A	1 X base earnings	1 X base earnings
Employee Contribution	N/A	0%; company paid May opt-out	0%; company paid

Basic and Optional Life Insurance

Current & Proposed

Benefits	FBC – Current	FBCE – Current	Proposed Plan
Employee Optional Life			
Benefit Schedule	Units of $25,000 to maximum of $750,000	Units of $50,000 to maximum of $750,000	Units of $50,000 to maximum of $750,000
Employee Contribution	100%	100%	100%
Optional Dependant Life			
Spouse	Units of $25,000 to maximum of $250,000	Units of $50,000 to maximum of $750,000	Units of $50,000 to maximum of $750,000
Child	Units of $5,000 to maximum of $25,000	$10,000	$10,000
Employee Contribution	100%	100%	100%

Accidental Death and Dismemberment

Current & Proposed

Benefits	FBC – Current	FBCE – Current	Proposed
Employee Basic 24-Hour Accident			
Benefit Schedule	$50,000	None	None
Employee Contribution	0%; Company paid	N/A	N/A
Optional AD&D			
Employee Benefit	Units of $25,000 to maximum of $500,000	Units of $50,000 to maximum of $500,000	Units of $50,000 to maximum of $500,000
Spouse Benefit	None	Units of $50,000 to maximum of $500,000	Units of $50,000 to maximum of $500,000
Child Benefit	None	$10,000	$10,000
Employee Contribution	100%	100%	100%
Business Travel Accident			
Employee Benefit	None	3 x base earnings to maximum of $1,000,000	3 x base earnings to maximum of $1,000,000
Employee Contribution	N/A	0%; company paid	0%

Short Term Disability

Current & Proposed

	FBC – Current		FBCE – Current		Proposed	
Benefit Amount	Initial weeks at 100%, remainder of weeks at 70% based on service		Initial weeks at 100%, remainder of weeks at 70% based on service		Initial weeks at 100%, remainder of weeks at 70% based on service	
Benefit Schedule	Years of Svc	# Weeks at 100%*	Years of Svc	# Weeks at 100%*	Years of Svc	# Weeks at 100%*
	All	13	<1	3	<1	3
			1	5	1	5
	*Balance of 26 weeks at 70%		2	7	2	7
			3	10	3	10
			4	13	4	13
			5	15	5	15
			6	17	6	17
			7	19	7	19
			8	21	8	21
			9	24	9	24
			10+	26	10+	26
			*Balance of 26 weeks at 70%		*Balance of 26 weeks at 70%	
Benefit Period	26 weeks		26 weeks		26 weeks	
Employee Contribution	0%; company paid		0%; company paid		0%; company paid	

Long Term Disability

Current

Classes	FBC Option 1	FBC Option 2	FBCE Option 1	FBCE Option 2	FBCE Option 3	FBCE Option 4
Benefit Schedule	70%	55%	70%	60%	70%	60%
Overall Maximum	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month
Elimination Period	26 weeks	26 weeks	26 weeks	26 weeks	26 weeks	26 weeks
Cost of Living Adjustments	None	None	None	None	Indexed with CPI to 5% maximum	Indexed with CPI to 5% maximum
Definition of Disability	2 years own occupation; any occupation thereafter	2 years own occupation; any occupation thereafter	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job
Benefit Period	To age 65	To age 65	To age 65	To age 65	To age 65	To age 65
Tax Status of Benefit	Taxable	Non-taxable	Taxable	Non-taxable	Taxable	Non-taxable
Employee Contribution	100%; flex credits only	100%; payroll deduction only	100%; flex credits only	100%; payroll deduction only	100%; flex credits only	100%; payroll deduction only

Long Term Disability

Proposed

Classes	Option 1	Option 2	Option 3	Option 4
Benefit Schedule	70%	60%	70%	60%
Overall Maximum	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month
Elimination Period	26 weeks	26 weeks	26 weeks	26 weeks
Cost of Living Adjustments	None	None	Indexed with CPI to 5% maximum	Indexed with CPI to 5% maximum
Definition of Disability	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job
Benefit Period	To age 65	To age 65	To age 65	To age 65
Tax Status of Benefit	Taxable	Non-taxable	Taxable	Non-taxable
Employee Contribution	100%; flex credits only	100%; payroll deduction only	100%; flex credits only	100%; payroll deduction only

Provincial Health Care

Current & Proposed

	FBC Option 1	FBC Option 2	FBCE Option 1	FBCE Option 2	Proposed Option 1	Proposed Option 2
Benefit	No coverage	Coverage	No coverage	Coverage	No coverage	Coverage
Employee Contribution	N/A	0%; company paid	N/A	100%; employee-paid	N/A	100%; employee paid

Extended Health Care Benefit

Current

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
Deductible	$0	$0	$100 per person	$0	$0
Hospital					
• Semi–Private	0%	100%	60%	80%	100%
• Convalescent Hospital	Not covered	$40 per person per day to maximum of 180 days	Not covered	Not covered	Not covered
Prescription Drugs					
• Coinsurance	85%	100%	60%	80%	100%
• Drugs Covered	Legally requiring prescription, plus life-sustaining drugs (lowest cost alternative), smoking cessation (lifetime max $500) and fertility (lifetime max $3,000)	Legally requiring prescription, plus life-sustaining drugs (lowest cost alternative), smoking cessation (lifetime max $500) and fertility (lifetime max $3,000)	Legally requiring prescription, plus life-sustaining drugs (lowest cost alternative)	Legally requiring prescription, plus life-sustaining drugs, smoking cessation (lifetime max $350 lifetime), fertility (lifetime max $3,000) and erectile dysfunction (max $1,000/year)	Legally requiring prescription, plus life-sustaining drugs, smoking cessation (lifetime max $350 lifetime), fertility (lifetime max $3,000) and erectile dysfunction (max $1,000/year)
• Drug Card	Yes	Yes	Yes $8.50 dispensing fee maximum	Yes $8.50 dispensing fee maximum	Yes $8.50 dispensing fee maximum

Note:
FBCE Option 1 is opt-out (i.e. no coverage provided).

Extended Health Care Benefit (Cont'd)

Current (Cont'd)

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
Coinsurance on Services/Supplies	100%	100%	60%	80%	100%
Private Duty Nursing	$25,000 per person per 3 years	$50,000 per person per 3 years	60%; $25,000 lifetime	80%; $25,000 lifetime	100%; $25,000 lifetime
Hearing Aids	No coverage	$750 / 5 years	60% Children only: $500 / 5 years	80%; $500 / 5 years	100%; $500 / 5 years
Vision Care	No coverage		No coverage		
• Coinsurance		100%		80%	100%
• Eyeglasses / contacts		$300 / 24 months		$150 / 24 months	$250 / 24 months
• Eye exams		1 exam / year		$100 / 24 months	$100 / 24 months
• Laser eye surgery		Included in eyeglasses / contacts coverage		No coverage	No coverage
Paramedical Services:	No coverage		No coverage		
• Physiotherapist		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Massage Therapist		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Chiropractor		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Naturopath		No coverage		80%; $250 / year	100%; $400 / year
• Speech Therapist		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Psychologist		100%; $500 / year		80%; $250 / year	100%; $400 / year

Extended Health Care Benefit (Cont'd)

Current (Cont'd)

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
• Podiatrist/chiropodis		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Acupuncturist		No coverage		80%; $250 / year	100%; $400 / year
• Dietician		No coverage		80%; $250 / year	100%; $400 / year
Orthopedic Shoes	No coverage	$150 / year per person	No coverage	80%; $400 / year adult; $200 / year child	100%; $500 / year adult; $300 / year child
Orthotics	No coverage	$150 / year per person	No coverage	80%; $200 / 24 months	100%; $400 / 24 months
Out of Country Emergency	100%	100%	100%	100%	100%
Overall Maximum	$1 million per incident	$1 million per incident	$1 million lifetime	$1 million lifetime	$1 million lifetime

Note:

FBCE Option 1 is opt-out (i.e. no coverage provided except for emergency out of county and travel assistance).

Extended Health Care Benefit

Proposed

Benefit	Option 2	Option 3	Option 4
Deductible	$100	$0	$0
Hospital			
• Semi–Private	60%	80%	100%
• Convalescent Hospital	Not covered	Not covered	Not covered
Prescription Drugs			
• Coinsurance	60%	80%	100%
• Drugs Covered	Formulary*	Formulary* plus contraceptives, smoking cessation (lifetime maximum $350) and fertility drugs (lifetime maximum $3,000)	Formulary* plus contraceptives, smoking cessation (lifetime maximum $350) and fertility drugs (lifetime maximum $3,000)
• Drug Card	Yes - $8.50 dispensing fee maximum	Yes - $8.50 dispensing fee maximum	Yes - $8.50 dispensing fee maximum

*Formulary to be determined

Note:
Option 1 is opt-out; (i.e.: no coverage except for emergency out of country and travel assistance)

Extended Health Care Benefit (Cont'd)

Proposed (Cont'd)

Benefit	Option 2	Option 3	Option 4
Coinsurance on Services/Supplies	60%	80%	100%
Private Duty Nursing	$15,000 / year	$20,000 / year	$25,000 / year
Hearing Aids	60% Children only; $500 / 5 years	80%; $500 / 5 years	100%; $500 / 5 years
Vision Care	No coverage		
• Coinsurance		80%	100%
• Eyeglasses / contacts		$150 / 24 months	$250 / 24 months
• Eye exams		$100 / 24 months	$100/ 24 months
• Laser eye surgery		No coverage	No coverage
Paramedical Services:	No coverage		
• Physiotherapist		80%; $250 / year	100%; $400 / year
• Massage Therapist		80%; $250 / year	100%; $400 / year
• Chiropractor		80%; $250 / year	100%; $400 / year
• Naturopath		80%; $250 / year	100%; $400 / year
• Speech Therapist		80%; $250 / year	100%; $400 / year
• Psychologist		80%; $250 / year	100%; $400 / year
• Podiatrist/chiropodist		80%; $250 / year	100%; $400 / year
• Acupuncturist		80%; $250 / year	100%; $400 / year
• Dietician		80%; $250 / year	100%; $400 / year

Extended Health Care Benefit (Cont'd)

Proposed (Cont'd)

Benefit	Option 2	Option 3	Option 4
Orthopedic Shoes	No coverage	$400 / 2 years adult; $200 / 2 years child	$500 / 2 years adult; $300 / 2 years child
Orthotics	No coverage	$200 / 24 months	$400 / 24 months
Out of Country Emergency maximum	100%	100%	100%
Overall Maximum	$1 million lifetime	$1 million lifetime	$1 million lifetime

Note:

Proposed Option 1 is opt-out (i.e. no coverage provided except for emergency out of county and travel assistance).

Dental

Current

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
Deductible	$0	$0	$0	$0	$0
Coinsurance					
• Basic	100%	100%	60%	90%	100%
• Major	No coverage	50%	50%	70%	80%
• Orthodontia	No coverage	50% (Children only)	No coverage	50%	60%
Maximum					
• Basic	1 exam / year and up to 8 units of scaling / year	2 exams / year and up to 16 units of scaling / year	$1,500 / year combined with Major	$2,500 / year combined with Major	$3,000 / year combined with Major
• Major	N/A	$1,500 / year per person	$1,500 / year combined with Basic	$2,500 / year combined with Basic	$3,000 / year combined with Basic
• Orthodontia	N/A	$3,000 lifetime / child	N/A	$3,000 lifetime	$3,500 lifetime

Note:
Option 1 for FBCE is opt-out (i.e. no coverage provided).

Dental

Proposed

Benefit	Option 2	Option 3	Option 4
Deductible	$0	$0	$0
Coinsurance			
• Basic	60%	90%	100%
• Major	50%	70%	80%
• Orthodontia	No coverage	50%	60%
Maximum			
• Basic	$1,500 per year combined with Major	$2,500 per year combined with Major	$3,000 per year combined with Major
• Major	$1,500 per year combined with Basic	$2,500 per year combined with Basic	$3,000 per year combined with Basic
• Orthodontia	N/A	$3,000 lifetime	$3,500 lifetime

Note:
Option 1 is opt-out (i.e. no coverage provided).

Paid Time Off and Other Benefits

Current

Benefit	FBC – Current	FBCE – Current	Proposed
Vacation Schedule			
	Years of Service / Vacation Days <1 / up to 15 days 1 - 6 / 15 7 - 15 / 20 16 - 24 / 25 25+ / 30	Years of Service / Vacation Days <1 / up to 15 days 1 - 7 / 15 8 - 17 / 20 18 - 24 / 25 25+ / 30	• Proposals A and B: Same as FBCE • Proposals C and D: Same as FBC
Carry Forward	Not permitted	May carry forward 5 days per year to a maximum bank of 10 days	May carry forward 5 days per year to a maximum bank of 10 days
Purchased days in flex plan	Not available	Employees may purchase up to 10 days off per year using Power Credits	Employees may purchase up to 10 days off per year using Power Credits
Statutory Holidays	10 company scheduled holidays plus 2 employee scheduled holidays	11 company scheduled holidays	• Proposals A and B: 11 company scheduled holidays • Proposals C and D: 10 company scheduled holidays plus 2 employee scheduled holidays
Earned Days Off (EDO)	Employees may earn up to 12 EDOs per year by working longer hours	Employees may earn 17 scheduled EDOs by electing to work a longer core day	Employees may earn up to 12 EDOs per year by working longer hours
Employee Assistance Plan			
Provided	Yes	Yes	Yes

Post-Retirement Benefit Program Design

Current Plans

- FBC's post-retirement benefits (PRB) program has been in a state of evolution for several years:
  - Previous program provided insured-style benefits for life
  - FBC considered moving to a defined contribution style health spending account (HSA) allocation of $2,000 per year for life
  - Eventually, FBC opted to continue active EHC, dental and MSP coverage to age 65 with no benefits after 65
- Effective January 1, 2004, FBCE implemented a new PRB program
  - The new program was voluntary for employees retiring during 2005
  - Commencing January 1, 2006 the program is mandatory for all newly retiring employees
  - The new program consists of the following benefits:
    - HAS allocation of $2,500 per year
    - High-deductible "security" extended health program
    - Life insurance

Overview

Current & Proposed

	FBC – Current[1]	FBCE – Current	Proposed
Eligibility	Age 55 with 10 years of service	Full time employees retiring on/after age 55 with 10 years of service	Full time employees retiring on/after age 55 with 10 years of service
Annual HSA Allocation	N/A	$2,500	$2,500
"Security" Extended Health Care Plan Provided?	N/A	Yes	Yes
Continuation of active EHC dental coverage?	Yes, to age 65	No	No
Provincial MSP premiums paid?	Yes, to age 65	No	No
Life Insurance	None	$10,000	$10,000
Survivor Coverage	Coverage continues to spouse until employee would have attained age 65	Security plan and 50% of HSA amount provided for lifetime of surviving spouse*	Security plan and 50% of HSA amount provided for lifetime of surviving spouse*

* HSA reduced by 50% at January 1 following the death of the retiree

Note:

1 As directed by FBC, the PRB program described here does not reflect the benefits currently valued for the company's financial statements. The benefits valued for the financial statements are as follows:

– Health Spending Account of $2,000 / year; and

– Provincial MSP premiums.

Post-retirement Benefit Transition & Implementation

- Legal
  - FBC should seek legal review of all active employee communications and notice period to ensure that there will be a low risk of legal challenge from modifying the program
  - The proposed program is likely more generous than the current PRB program for FBC employees, so this risk may not be a major concern
- Governance
  - Need to develop a plan text that describes the post-retirement benefits, eligibility, and key administrative rules, such as:
    - adding new dependents,
    - survivor coverage,
    - implications of opting out,
    - confirming eligibility each year,
    - process for issuing T4A for provincial medical premiums
- Communication
  - Communicate plan to employees and update communication materials
- Administration
  - Develop implementation plan with insurers to ensure appropriate claims eligibility classes & divisions are established

Benchmarking Analysis

Appendices

Peer Group

Appendix I

- ATCO Group
- BC Hydro
- Canadian Pacific Railway
- Capital Power Corporation
- Catalyst Paper
- Chevron
- ConocoPhillips
- Enbridge Gas Distribution
- ENMAX
- EPCOR
- Finning (Canada)
- FortisAlberta
- Insurance Corporation of BC
- Manitoba Hydro
- Methanex
- Nexen
- Spectra Energy
- Suncor
- Teck Resources
- TELUS
- TransAlta
- TransCanada PipeLines

Methodology

Appendix II

Valuation of Pensions and Benefits

- Pension and benefits data have been obtained using BENVAL® from Towers Watson's Canadian Benefits Data Source (BDS). The BDS contains detailed information on benefit programs offered by approximately 475 Canadian employers.
- BENVAL® is Towers Watson's methodology used to develop comparative values for the benefit plans provided by a group of companies. This methodology determines values using a standard set of actuarial methods and assumptions applied to a common employee population.
- To develop such values, benefits are initially analyzed in terms of when they become payable.
  - Those benefits payable in the future – defined benefit pension plans and post-retirement benefits – are valued in terms of anticipated prospective benefit payments being allocated over the employee's entire working history (Projected Unit Credit with service prorate method).
  - Those benefits potentially payable over the current year – defined contribution pension plans, pre-retirement death, disability benefits, and vacations and holidays – are valued based on the probabilities of the various events occurring within the year, multiplied by the value of the benefit (Term Cost method).
  - For health care and dental care coverage, the Term Cost method is based on the expected premium rate charged by an insurer for the coverage.
  - No other benefits are valued – parental leave and employee assistance programs for instance.
- The employer provided value is determined by deducting employee contributions from the total value.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

- An explanation of how each benefit plan is valued follows:

Defined Benefit Pension Plans

- The following elements are considered in determining comparative values for defined benefit pension plans: normal and early retirement benefits, disability benefits, pre- and post-retirement death benefits, termination benefits, and post-retirement pension adjustments.
- Post retirement pension adjustments are valued according to plan provisions or the actual company's policy when not stated in plan provisions.
- When a plan offers the possibility to switch between a defined contribution pension plan and a defined benefit pension plan, employees are deemed to select the defined contribution pension plan if they are younger than age 45 and the defined benefit pension plan at age 45. When an employee is hired after the attainment of age 45, he is deemed to participate in the defined benefit pension plan during his entire career.
- Plans are valued in accordance with the legislation where the plan is registered.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Defined Contribution Pension Plans, Savings, Profit Sharing, and Stock Purchase Plans

- Plans are valued by determining employee and employer contributions made during the year of valuation.
- Employee contributions are adjusted to reflect savings opportunity depending on available income and level of employer match.
- Contribution levels to Profit Sharing plans are determined by taking the average of the actual past five years' contributions to the plan.

Life Insurance Plans

- Values for the following benefits are calculated: pre- and post-retirement group life insurance, accidental death and dismemberment benefits, and survivor income benefits.
- The amount of optional insurance elected is based on the level of company provided coverage and salary.

Disability Plans

- Short-term disability benefits include salary continuance and sickness plans.
- Values are determined according to specific plan provisions including waiting periods and benefit coordination.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Health Care and Dental Care Plans

- Values are generated for pre- and post-retirement coverage. Post-retirement premiums are increased to reflect future inflation.
- Values are determined based on plan deductibles, coinsurance, and maximums as well as eligibility requirements.
- Vision care and hearing aid benefits are included in the Health Care plan value whether they are covered under the Health Care plan or a separate plan.
- Amounts allocated to the Health Care Spending Account are also included in the Health Care plan value.
- The provincial health care premiums are not included in the valuation.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Vacation and Holidays

- The value for vacation is determined based on the number of vacation days available. This includes bonus days when applicable. The number of days are determined in accordance with the company's schedule which is, usually, based on the employees' number of years of service.
- When the plan does not allow for the payment of unused vacation days during employment, we assume that employees with more than four weeks of vacation will forfeit some vacation days at the end of each year.
- The value for holidays is determined based on the number of holidays available. This includes all regular scheduled holidays and personal days.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Flexible Benefits

- The value determined for these benefits is based on the highest enrolled option for each plan.
- When not determined by the plan design, flexible benefit credits are allocated in the following order: health and dental care benefits, life insurance benefits, and disability benefits.

Methodology

Appendix II

Summary of Common Employee Population

AGE (% Female)		COMPLETED YEARS OF CREDITED SERVICE							
		Less than 1	1	2 - 4	5 - 9	10 - 19	20 - 29	30 or More	Total
0 - 19 (46%)	Number	1							1
	Avg. Base Pay	$ 29,000							$ 29,000
20 - 24 (42%)	Number	98	80						178
	Avg. Base Pay	$ 41,000	$ 41,000						$ 41,000
25 - 29 (40%)	Number	217	176	409	85				887
	Avg. Base Pay	$ 50,000	$ 50,000	$ 50,000	$ 52,000				$ 50,192
30 - 34 (40%)	Number	229	186	432	386	145			1,378
	Avg. Base Pay	$ 56,000	$ 56,000	$ 56,000	$ 59,000	$ 58,000			$ 57,051
35 - 39 (40%)	Number	218	177	411	493	534			1,833
	Avg. Base Pay	$ 58,000	$ 58,000	$ 58,000	$ 57,000	$ 60,000			$ 58,314
40 - 44 (40%)	Number	176	143	332	384	632	262		1,929
	Avg. Base Pay	$ 61,000	$ 61,000	$ 61,000	$ 62,000	$ 71,000	$ 70,000		$ 65,698
45 - 49 (40%)	Number	110	90	209	294	445	427		1,575
	Avg. Base Pay	$ 60,000	$ 60,000	$ 60,000	$ 64,000	$ 69,000	$ 74,000		$ 67,085
50 - 54 (40%)	Number	75	61	141	166	317	391	158	1,309
	Avg. Base Pay	$ 67,000	$ 67,000	$ 67,000	$ 61,000	$ 68,000	$ 75,000	$ 77,000	$ 70,078
55 - 59 (37%)	Number	26	21	50	95	188	172	135	687
	Avg. Base Pay	$ 57,000	$ 57,000	$ 57,000	$ 61,000	$ 64,000	$ 72,000	$ 91,000	$ 69,905
60 + (30%)	Number	9	7	16	28	76	51	36	223
	Avg. Base Pay	$ 66,000	$ 66,000	$ 66,000	$ 52,000	$ 62,000	$ 69,000	$ 81,000	$ 65,987
Total	Number	1,159	941	2,000	1,931	2,337	1,303	329	10,000
	Avg. Base Pay	$ 55,912	$ 55,931	$ 57,313	$ 59,708	$ 66,036	$ 73,036	$ 83,182	$ 62,421

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Economic Factors	
Valuation interest rate	7.0% per year
Salary escalation	4.0% per year
Escalation of Year's Maximum Pensionable Earnings	3.0% per year
Inflation	2.5% per year
Increase in medical and dental premiums for post-retirement benefits valuation	4.0% per year

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Demographic Factors	
Mortality	• 1994 Uninsured Pensioner mortality without margins and 25 years of mortality improvement
Disability • STD • LTD • Other plans	• Based on Commissioner's Disability Table, the Society of Actuaries TSA Group Table, and Towers Perrin's experience • Society of Actuaries 1981 Report on Mortality and Morbidity Experience, with adjustment • None
Termination of Employment	See table on next page
Retirement	See table on next page
Employee/family status	Employees are assumed to be married. Female spouses are assumed to be three years younger than male spouses. Employees are assumed to elect family coverage. Family is assumed to consist of two adults and two children.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Termination of Employment

Age at Termination	Termination Rate
20 - 24	15% each year
25 - 30	10% each year
31 - 45	Starts at 9.5% at age 31 and reduced by 0.5% each age
46 - 54	2% each year
55 +	0% each year

Illustrative Probability of Retirement

Age at Retirement	Age of Unreduced Benefit			
	65	62	60	55
50	2%	2%	2%	2%
55	4%	4%	4%	15%
60	10%	10%	15%	15%
62	20%	30%	30%	50%

For example, under a plan that provides an unreduced benefit at age 62, 30% of active employees will retire at age 62.

Attachment 80.1

Letter of Understanding #3
Between
Terasen Gas Inc.
(Customer Services Centres)
And
Canadian Office and Professional Employees Union, Local 378

Re: Market Competitiveness

The parties agree that in order to ensure the long term viability of the Customer Care Business Unit it is critical that the total compensation package for employees remain competitive with other similar customer care entities. This will support our shared objectives of:

- Being able to attract and retain qualified employees
- Maintaining cost competitiveness and sustainability on an ongoing basis

Meeting these objectives is in the best interest of the Union, the Company and our Customers. As such the parties agree that a joint market comparator survey will be conducted in advance of the expiry of the collective agreement or as otherwise agreed by the parties, and that such survey will evaluate all key elements of total compensation including base wages, incentive pay, paid time off, pensions and benefits.

It is further agreed that an appropriate comparator group would include the following companies:

- Accenture Business Services
- Aeroplan
- BCAA
- Coast Mountain Bus Company
- Rogers
- Shaw
- Telus

The parties may change this list of companies by mutual agreement

For Terasen Gas	For COPE, Local 378
Jeff Marwick Manager, Labour Relations	Kevin Smyth Union Representative

Aug/19/09
Date

Attachment 80.1.1

FILED CONFIDENTIALLY

Attachment 81.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 81.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 81.5

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 81.6

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 88.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 97.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 97.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 106.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 110.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 111.3

97.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, pp. 5-6

Commodity Risk

On page 5, FEI provides a snapshot of its business risks and concludes on page 6 that "Considered together, FEI business risk and regulatory risk is best characterized as being similar - no lower, and perhaps somewhat higher- than what it was in 2009."

97.1 Would FEI agree that the large drop in natural gas commodity prices and the expected low prices into the future, compared to expected large increases in tier 2 electricity rates, provides the single largest change in business risk for FEI? If not, please explain.

Response:

This response also addresses BCUC IRs 1.2.1, 1.2.1.1, 1.6.2 (b), 1.98.1, 1.99.1, 1.101.1, and 1.106.1 as well as BCPSO IR 1.1.1.

While FEI agrees that the operating cost advantage of natural gas versus electricity compared to the 2009 levels has improved due to the decline in natural gas commodity prices and the increase to electricity rates, FEI does not agree that it was the single largest change in business risk for FEI since 2009. In fact, the decline in commodity price has had little impact on FEI's overall business risk, mainly due to two reasons:

- Firstly, as discussed in Section 5 of Appendix H, natural gas commodity price is one factor impacting price competitiveness of natural gas in BC relative to electricity. Other factors include natural gas price volatility, the relative purchase and installation costs of natural gas appliances compared to electric appliances. As such, even with lower commodity prices, there has not been a significant improvement in FEI's throughput levels (with the exception of industrial load) for space and water heating, which is FEI's core business.
- Secondly, as evident in Appendix H, there are also non-price competitive factors (climate change and energy policies, customer perception of energy and the shift towards smaller, higher density housing), that impact FEI's throughput levels and it is due to these factors that despite the decline in natural gas commodity prices, FEI continues to face business risk trends similar to those identified in 2009.

Each of these reasons are further discussed below. In addition, recent operational and research results will be explored that suggest the business risk FEI faces continues to increase.

Energy Price Risk Factors

There are a number of factors that impact the price competitiveness of natural gas in BC relative to electricity and these include natural gas commodity cost relative to electricity, natural gas price volatility, and relative installation costs of natural gas equipment compared to electric equipment. Despite the fact the natural gas commodity cost relative to electricity has improved over the last few years due to lower commodity prices, the other two factors continue to impact the operating price advantage of natural gas over electricity in BC.

Natural Gas Commodity Prices

Natural gas commodity prices have declined and therefore improved the operating cost of natural gas over electricity in recent years. As stated on page 17 of Appendix H, the operating cost advantage has been partially offset by the carbon tax increases in the same period (from approximately \$0.50/GJ in 2008 to \$1.50/GJ in 2012). Furthermore, as demonstrated by Figure 22 and 28 of Appendix H, despite the lower commodity price environment over the last couple of years, there has been little change in residential average use per customer and customer additions. Therefore it is difficult to separate what influence lower commodity prices have had on consumption levels from other cost or non-price related factors. The exception is for the industrial sector, whereby, as stated on page 36 of Appendix H, FEI experienced a modest increase in throughput in the industrial sector as some industrial customers have fuel switched towards natural gas to take advantage of the lower natural gas prices compared to their alternatives.

In comparing the natural gas price to electricity, the expected increases in step 2 electricity rates may further enhance the operating price advantage of natural gas. However, there is uncertainty regarding future natural gas prices as discussed in Section 5.1 of Appendix G of the Application and there is no guarantee that this operating price advantage will continue to this degree in the future. It is also worth mentioning the fact that step 2 electricity rates do not apply to all energy consumption (e.g. step 1 applies to water heating). Specifically, many newly constructed homes, which are typically smaller and more energy efficient, consume most of their consumption at the step 1 electricity rate. This is especially true for hot water heating applications in which almost all of a typical residential consumer's consumption is at the step 1 rate. Further, step 1 electricity rates are not expected to increase as much as step 2 electricity rates, and as such, FEI will continue to be especially challenged in retaining and attracting load for hot water heating applications.

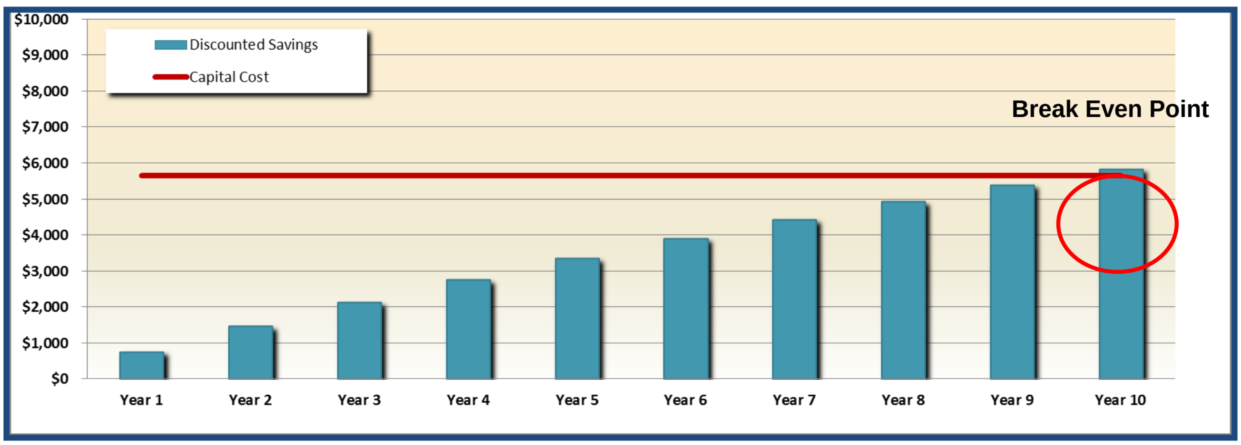
Natural Gas Price Volatility

As discussed in Section 5.2 of Appendix H, many of the past risk mitigation strategies to reduce price volatility are no longer in place and therefore a greater portion of FEI's supply portfolio is subject to market price fluctuations. Therefore, the risk associated with market price volatility is considered to be higher than in 2009, somewhat offsetting the lower risk associated with the drop in natural gas prices.

Upfront and Installation Costs

As discussed in Section 5.3 of Appendix H, natural gas equipment is significantly more expensive than electrical equipment for space heating and this higher upfront capital costs of natural gas end-use applications erodes natural gas' operating cost advantage as compared to electricity and can influence energy choices, particularly because builders and developers tend to be more influenced by capital costs alone. Figures 14 and 15 from Appendix H show that when capital cost is added to the cost of delivered energy (natural gas or electric), the difference in annual costs is much smaller. In fact, as demonstrated in the figure below, if a customer were to calculate when they would break even by using natural gas they would find it takes approximately 10 years to recover the additional cost of natural gas equipment via savings from the operating cost differential between natural gas and electricity.

Capital Cost Recovery for Gas Furnace and Hot Water Tank



Thus, the continued difference in capital cost for natural gas equipment in comparison to electricity equipment means that from a total cost perspective, natural gas may not have a competitive advantage over electricity and as such it is not favored in certain applications, particularly within the multi-family dwellings. As stated in Appendix H (page 24), the impact to the rate comparisons of natural gas against electricity depends on the customer's consumption levels for electricity. For example, water heating load may be better compared to Step 1 electricity rates because it generally has a flat yearly profile versus space heating which would have a winter profile (Step 2).

Previous research conducted in 2010 suggested that builders and developers also install electric baseboard heating solutions because they do not require venting or ducting and they allow for greater floor plan design flexibility. These findings were further affirmed in 2012 when a cross section of builders and developers indicated that:

> *"The two most significant barriers to choosing gas are the up-front capital cost requirements and greater complexity of the installation, relative to electricity. This can be especially challenging in lower cost developments and also MURBs (multi-unit*

residential buildings), where space is at a premium and additional ducting can compromise the utilization of limited floor space."[6]

This means that regardless of any commodity price advantage, FEI will continue to be challenged in capturing new customers.

Non-Energy Price Risk Factors

The decline in commodity price has not resulted in a favorable impact to throughput levels mainly due to other non-price factors, such as climate change and energy policies, as well as risks related to market shifts (such as customer perception of energy and housing types), which are significantly higher since 2009 and all of which continue to challenge FEI in retaining and attracting customers even in the current lower commodity price environment.

Energy Policies and Legislation

As discussed in Section 9 of Appendix H, since 2007 energy policies at the Provincial level have focused on energy efficiency and role of renewable and alternative energy, and more specifically discouraged the use of carbon based fuels, including natural gas (regardless of the energy price differences). Despite new policy developments in the Province in promoting the role of natural gas in the transportation sector, the role of natural gas in its traditional market of space and water heating continues to be challenged by the climate change and energy policies and more local and municipal governments are mandating certain renewable energy solutions in new developments.

In addition, as mentioned on page 12 of Appendix H, regulations and standards such as the proposed changes to National Minimum Efficiency Standards for domestic water heating systems impact and reduce natural gas consumption and use per customer account over time. FEI forecasts that approximately 50,000 water heaters will fail annually. In 2016, natural gas water heaters will require a 0.67 EF and a dedicated electrical plug. In 2020, the minimum EF rises to 0.80. These efficiency standards coupled with higher capital and installation costs for natural gas hot water tanks will dramatically shift the cost advantage to electric models.

Customer Perception of Energy

As discussed in Section 6.2 of Appendix H, whereas energy price may have played a role in customers' energy choices historically, more and more customers are now moving away from choosing natural gas as energy of choice and demanding greener alternatives. In 2011 research conducted by FEI, it is evident that customer commitment to natural gas dropped sharply from 2007 scores. [7] Customers' interest in alternative energy options such as geo-

---

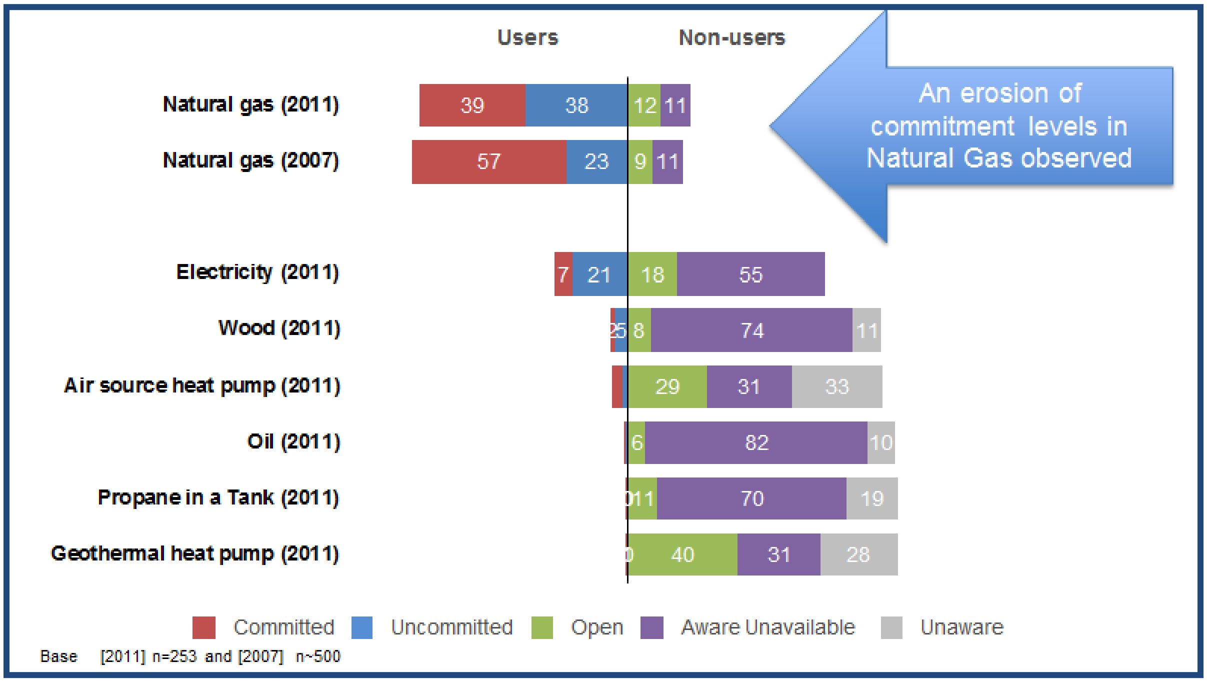
[6] Customer Attachment Study, Ipsos, July 2012, 12-029608-01, pp. 2.

[7] Commitment is calculated using a TNS Global Research approach called the Conversion Model™. This approach measures four dimensions of consumer loyalty as follows:

- Overall rating: How do users and aware non-users rate each energy source?

exchange and air-source heat pumps exceeds that of natural gas or electricity. These results are portrayed in the figure below.

Lower Mainland Space Heating Preferences (2011 versus 2007)



These results reveal that despite the decline in natural gas commodity prices, FEI consumers do not look at natural gas for space heating as favourably as they did in 2007.

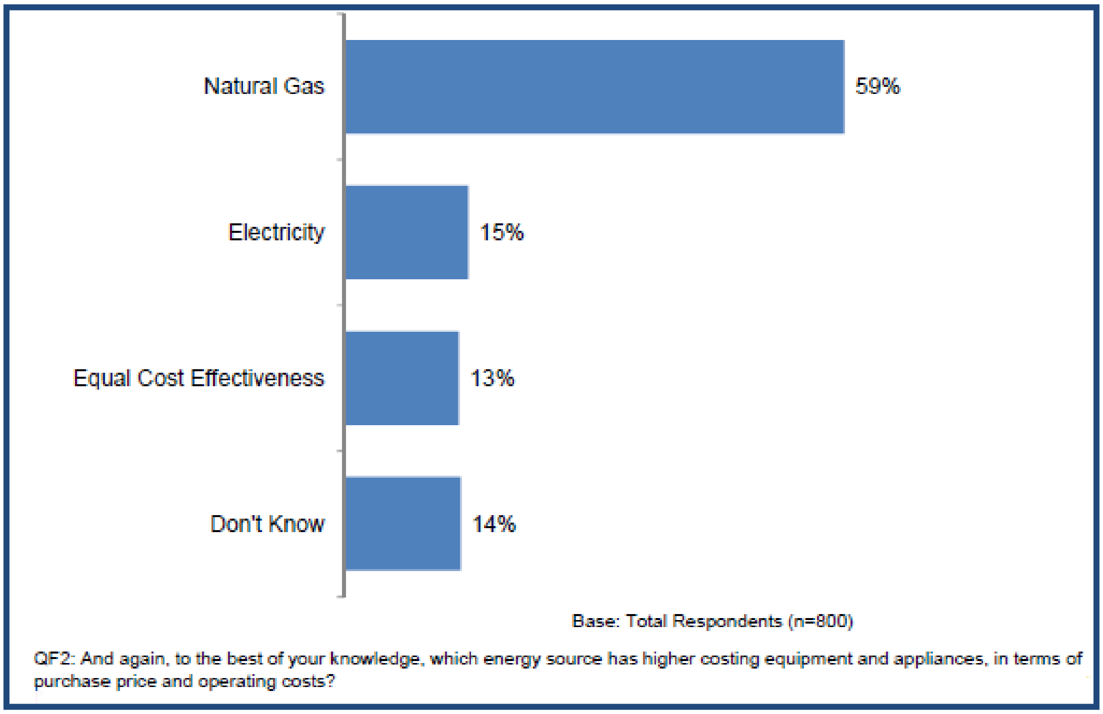
Other results from this same study further illustrate the mounting obstacles that natural gas faces. While a large minority (one in three customers) is either unclear or convinced that electricity is as or more cost effective for heating applications than natural gas, the majority (two in three) believe that natural gas is more expensive in terms of equipment price and ongoing operating costs[8]. This latter result is depicted in the figure below.

- Attitude to alternatives: How do all the alternative energy sources compare?
- Involvement: How important a decision is energy choice?
- Ambivalence: Are there many, few or no reasons to change from energy source currently used?

This research approach segments consumers into four primary groups. Existing natural gas customers can be committed users, people that are not likely to be swayed from using natural gas; or uncommitted. For example, Uncommitted natural gas users are reasonably ambivalent to natural gas and could easily be swayed to choose a competitive energy option. Likewise, there are two non-user groups. These two groups are called Open and secondly, Unavailable non-users. "Open" consumers are willing to consider an alternate energy option. However, those "Unavailable" will not consider the energy as a possible solution.

[8] Energy Source Usage Preferences Study – Topline Results, TNS Canada, December 2011 (R1786), pp. 33, 34.

Energy Source Considered More Expensive for Equipment and Operation



FEI is of the opinion that a contributing factor to some customer misconceptions can be found in results from a 2012 study called, "Alternatives for Managing Natural Gas Price Volatility." This study was undertaken to explore rate alternatives that focus on delivering choice for customers that want rate volatility reduction. To ensure customers understood the different options explored, the study evaluated customers' current understanding of the FortisBC natural gas bill. "Findings suggest that less than half of businesses (45%) and even fewer residents (35%) gave responses indicating that they feel confident that they understand the difference between delivery and commodity charges (assigning a rating of either 4 or 5 on a 5-point scale)."[9] Even after providing customers with the description of the bill charges, a large minority (42% of residential customers, and 33% of business customers) indicated ongoing confusion about their natural gas bill. This finding suggests that many consumers are ill-equipped to effectively compare natural gas and electric heating system costs. Pricing signals available through market commentary or through a comparison of one's electric and gas bills is unlikely to drive an informed investment decision because billing and energy terminology are not well understood by many consumers.

Housing Types and Builder Decision Making

As discussed in Section 6.3 of Appendix H, natural gas has a low penetration rate in multi-family dwellings and the increase in multi-family housing starts in recent years has a significant impact

[9] Alternatives for Managing Natural Gas Price Volatility, Sentis Research, September 10, 2012, pp. 7.

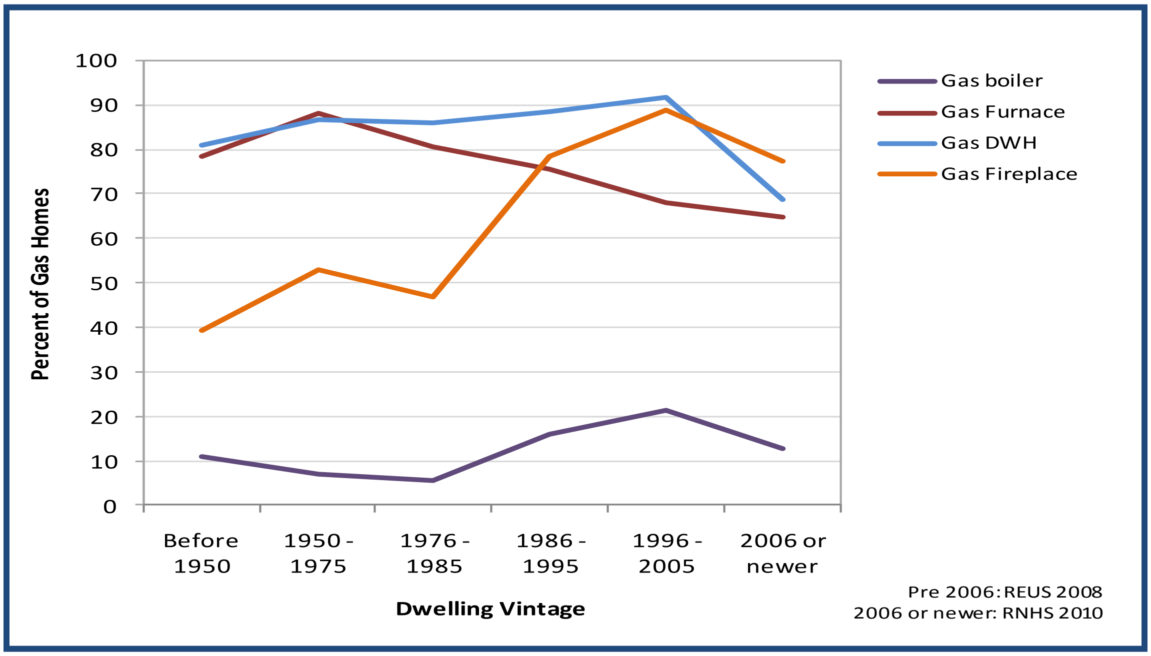
on natural gas use and capture rates. As stated on page 31 of Appendix H, the main underlying factor that influences the declining capture rates of natural gas is that builder decisions are being driven by capital cost savings and the ability to sell more useable living space. As installing natural gas application is economically unfavorable over electric equipment, natural gas will continue to be challenged.

While several of the research references in this response relate qualitative findings, the rapid change in natural gas use in the home is best demonstrated in results from a 2010 FortisBC study called Residential New Construction Research. This report underscores the rapid changes and increased risk FEI currently faces. It evaluated the space and domestic water heating fuels and equipment and other natural gas end-uses in homes built between 2006 and 2010. Results reveal tremendous differences from historic end-use research results. Specifically:

- The proportion of new homes using baseboard heaters is up significantly despite being the least desirable method of space heating from a homeowner's perspective.
- The proportion of gas homes with a gas furnace continues to decline.
- Air Source Heat Pumps ("ASHPs") are installed in 18% of gas homes built since 2005, with the incidence highest on Vancouver Island and in the Interior. As a result, gas is shifting to a secondary space heating role.
- Eight in every ten homes with ASHPs use either a gas furnace or gas fireplace as the other heating method.
- Geothermal is making inroads, with 4% of new homes reporting a geothermal heat pump system.

The figure below depicts the rapid erosion FEI has experienced in natural gas homes relying upon gas solutions for space heating, DWH, boilers and fireplaces.

Gas End-Use Trends – Gas Space & Water Heating



In summary, natural gas commodity price is just one factor that influences the overall price competitiveness of natural gas relative to electricity. Other factors include natural gas price volatility, purchase and installation costs of natural gas appliances, climate change and consumer perception of energy alternatives, energy policies and building codes, and the dramatic shift to higher density housing, especially MURBs. In aggregate, these factors support FEI's assertion that it continues to face business risk similar to that identified in 2009. As such, the FEU do not agree that the recent decline in natural gas commodity prices has been the biggest change to business risk since 2009.

Attachment 112.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 114.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 114.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 114.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 120.2

Terasen Gas Group 2008 Scorecard

December 2008 Results

		Results To Date	Status	Threshold	Target	Top-Out
FINANCIAL	1. Terasen Gas Group Net Earnings	$111.7m	Ahead	$102.0m	$105.2m	$108.4m
CUSTOMER	2. O&M per Customer	$229.15	On Track	$235.90	$231.31	$226.70
	3. Base Capital	$115.4m	Ahead	$132.6m	$124.8m	$117.0m
	4. Customer Satisfaction	79.7%	On Track	*76.0%*	*79.0%*	*82.0%*
KEY PROCESSES	5. Credit & Collections	0.24%	Ahead	0.45%	0.35%	0.33%
	6. Customer Additions	12,830	Needs Action	13,000	15,500	18,000
				-	Challenge	+
EMPLOYEE	7. Recordable Veh. Accid.	13	Needs Action	12	10	8
	8. Recordable Injuries	20	Ahead	34	28	22
	9. Wellness	5.1	Ahead	6.2	5.6	5.0
	10. Public Safety			*Service Quality Indicator*		

Ahead On Track Needs Attention Needs Action

Terasen Gas Group 2009 Scorecard

December 2009 Results

		Year End Actuals	Status	Threshold	Target	Top-Out
FINANCIAL	1. Terasen Gas Group Net Earnings	$112.4m	★	* $102.0m	$105.2m	$108.4m
CUSTOMER	2. O&M per Customer	$234.98	★	$242.85	$238.09	$233.33
	3. Base Capital	$107.7m	★	$125.6m	$116.5m	$107.5m
	4. Customer Satisfaction	80.1%	✚	*76.0%*	*79.0%*	*82.0%*
KEY PROCESSES	5. Credit & Collections	0.29%	★	0.45%	0.35%	0.33%
	6. Execution Against Regulatory Priorities		★	*Revenue Requirement and Cost of Capital Applications*		
				-	Challenge	+
EMPLOYEE	7. Recordable Vehicle Accidents	38	✚	45	39	33
	8. Recordable Injuries	28	★	37	31	25
	9. Wellness	5.3	★	6.1	5.6	5.1
	10. Public Safety		★	*Service Quality Indicator*		

******Gate for Payout*

★ Ahead ✚ On Track △ Needs Attention ■ Needs Action

Terasen Gas Group 2010 Scorecard

December 2010 Results

Terasen Gas

		Year end Results	Status	Threshold	Target	Top-Out
FINANCIAL	1. Terasen Gas Group Net Earnings	$127.3m	★ *	$118.8m	$122.5m	$126.2m
CUSTOMER	2. O&M per Customer	$254.18	✚	$260.75	$255.64	$250.53
	3. Base Capital	$98.9m	★	$123.0m	$111.8m	$106.2m
	4. Customer Survey Score	80.0%	✚	77.0%	80.0%	83.0%
KEY PROCESSES	5. Credit & Collections	0.18%	★	0.45%	0.35%	0.33%
	6. Integrated Energy Service Offerings	1.0	✚	Progress on new product development initiatives		
				-	Challenge	+
EMPLOYEE	7. Recordable Vehicle Accidents	47	■	44	38	32
	8. Recordable Injuries	32	■	32	26	20
	9. Wellness	4.0	★	5.8	5.3	4.8
	10. Public Safety	Top-out	★	*Service Quality Indicator*		

**Gate for Payout*

★ Ahead ✚ On Track △ Needs Attention ■ Needs Action

FortisBC Energy Group 2011 Scorecard

December 2011 Results

		Year end Results	Status	Threshold	Target	Top-Out
FINANCIAL	1. FortisBC Energy Group Net Earnings	$139.1m	Ahead *	$127.0m	$130.9m	$134.8m
CUSTOMER	2. O&M per Customer	$255.74	On Track	$264.91	$259.72	$254.53
	3. Base Capital	$114.9m	Ahead	$139.8m	$127.1m	$120.7m
	4. Customer Survey Score	79.3%	On Track	77.0%	80.0%	83.0%
KEY PROCESSES	5. Credit & Collections	0.32%	Ahead	0.45%	0.35%	0.33%
	6. Execution Against Regulatory Priorities		Ahead		*Regulatory Priorities*	
EMPLOYEE	7. Recordable Vehicle Accidents	47	Needs Action	49	43	37
	8. Recordable Injuries	24	On Track	33	27	21
	9. Wellness	4.5	On Track	5.3	4.8	4.3
	10. Public Safety		On Track		*Service Quality Indicator*	

***Gate for Payout** — Ahead — On Track — Needs Attention — Needs Action

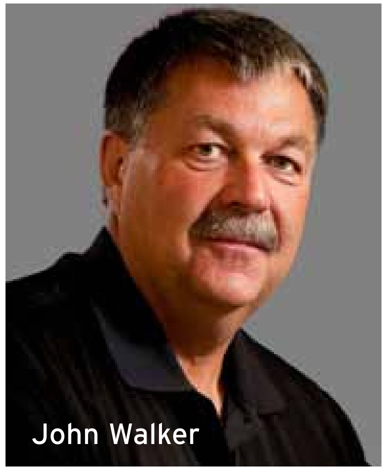
FORTIS BC™

FortisBC 2012 Gas corporate scorecard

Q4 performance results

FortisBC (Gas) achieved 140.3 per cent for 2012, with the fourth quarter capping a year of solid performance in almost all target areas.

We maintained our focus on customer service throughout the year with satisfaction results consistent with the target. The new measure, public contacts with pipelines, was significantly better than the average of the past three years.



2012 marked a year of improvement for driver safety performance with a lower number of vehicle accidents compared to the previous year. The ongoing focus on the **Drive to Zero** was communicated often and to all employees throughout the year. Still, we must remain vigilant and remember that avoiding preventable accidents is of the utmost importance to FortisBC and should be a priority for all employees.

Last year was an intense and successful year on the regulatory front, with a number of essential filings such as the Generic Cost of Capital, Common Rates and Amalgamation applications. Work is currently underway to prepare the company's next Revenue Requirement application. The gas division filed 62 major applications requesting approvals and responded to over 6,000 information requests, continuing the upward trend from 4,200 in 2011 and 2,300 in 2010. In total, 474 different BCUC filings were completed.

As we move forward on all major aspects of our business and focus our productivity, this scorecard will continue to serve as a gauge by which to measure our success.

Customer satisfaction

The customer satisfaction rating achieved gains in the residential, builder and developer and small commercial results, however this was offset by a decline in the large commercial score. The number of public contacts with our pipeline infrastructure continued to track well in the quarter, with results exceeding the annual target.

Safety

Vehicle accidents remained ahead of target, with the annual results achieving a top-out rating. We experienced 35 recordable vehicle incidents, significantly below our target and an improvement compared to 47 recordable incidents in 2011, continuing on a year-over-year improvement.

Regulatory

The company received the BCUC's decision on the Alternative Energy Services Inquiry, providing direction on how FortisBC's gas division can offer thermal energy services as a regulated utility service. The decision clarified regulations surrounding renewable natural gas and thermal energy services. It also proposed principles, guidelines and corporate structure for how the gas utility and other market participants should approach these offerings. The company also finished its participation in stage one of the Cost of Capital review proceeding where witnesses from the company testified before the BCUC.

Financial

We finished the year with strong financial results. Regulated earnings for the gas side totalled $138.1 million more than our target of $126.2 million.

Q4 fourth quarter performance results

Category	Measurement	Target	Results	Status
Customer	Customer survey score	80%	78.9% (9.06%)	Below target
	Public contacts with pipelines	18	13 (18.75%)	Ahead of target
Safety	All injury frequency rate (AIFR)	2.27	1.91 (15.0%)	Ahead of target
	Recordable vehicle incidents	44	35 (15.0%)	Ahead of target
Regulatory	Regulatory Performance	Subjective	(37.5%)	Ahead of target
Financial	Net earnings $ millions (excluding FortisBC Holdings Inc.)	$126.2	$138.1 (45.0%)	Ahead of target

Q4 performance results: 140.3%

	Performance Indicator	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Benchmark
1	**Emergency Response Time** Time Dispatched to Site - Emergency - Blowing Gas	20.7 minutes	22.7 minutes	22.5 minutes	23.4 minutes	23.8 minutes	**21.1 minutes**
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	98.3%	98.3%	99.2%	96.5%	96.5%	**95.0%**
3	**Speed of Answer – Non-Emergency** (% of calls answered within 30 sec.)	73.8%	76.7%	77.2%	74.7%	76.2%	**75.0%**
4	**Transmission Reportable Incidents**	2	0	0	0	2	**2**
5(a)	**Index of Customer Bills Not Meeting Criteria**	7.53	3.75	2.40	0.24	3.01	**5**
5(b)	**Percent of Transportation Customer Bills Accurate**	94.3%	96.0%	99.9%	100.0%	99.1%	**99.5%**
6	**Meter Exchange Appointment Activity**	94.5%	94.7%	94.2%	96.5%	96.5%	**92.2%**
7	**Accuracy of Transportation Meter Measurement First Report**	96.2%	98.7%	97.6%	98.1%	98.4%	**95.0%**
8	**Independent Customer Satisfaction Survey**	79.7%	80.1%	80.0%	79.3%	78.9%	**n/a**
9	**Number of Customer Complaints to BCUC**	90	58	26	3	3	**n/a**
10	**Number of Prior Period Adjustments**	15	21	14	19	5	**n/a**

	Directional Indicators					
1	Leaks per Kilometer of Distribution Mains	0.0016 57	0.0031 60	0.0073 140	0.0083 166	0.0085 169
2	Number of Third Party Distribution System Incidents	1,574	1,322	1,246	1,125	947

Attachment 139.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 140.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 140.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 140.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 141.4

Ipsos

Ipsos Reid

FORTIS BC™

Safety Awareness Tracking
2012 Wave 5 Report

January 21, 2013

Table Of Contents

Background and Objectives

Background

- FortisBC has regularly monitored the level of public knowledge of key natural gas safety indicators since 2001. From 2001 to 2009 public awareness remained at a level lower than desired. As a result, FortisBC initiated a public safety communications campaign in 2010 and 2011 to promote awareness and understanding of natural gas safety among residents of British Columbia.
- The 2012 media campaign began in early April with a series of radio tags. An initial baseline survey was conducted in March 2012, prior to the campaign launch, followed by four subsequent waves timed to monitor the campaign's effectiveness.

Objectives

- The purpose of this research is to measure the effectiveness of the 2012 communications campaign in increasing both awareness and understanding of natural gas safety issues. Specifically, the objective of the research is to track the effectiveness of the communications campaign in terms of ad and key message recall, as well as against historical gas safety awareness metrics.

Methodology

- Five waves of awareness tracking were conducted between March and December, 2012, with each wave comprising a total of about 300 telephone interviews among BC residents in FortisBC's service territory.
- The fifth wave was conducted between December 3-12, 2012.
- Quotas were set to obtain 120 surveys in the Lower Mainland, and 90 in each of Interior and Vancouver Island regions. At the data processing stage, the sample was weighted to match the distribution of FortisBC customers by region. Actual and weighted sample sizes for Wave 5 are shown below.

Region	Actual Sample	Weighted Distribution	Weighted Sample
Metro Vancouver/Fraser Valley	120	62.5%	188
Interior	90	27.4%	82
Vancouver Island	90	10.1%	30

- At the 95% level of confidence, the maximum margin of error for the total sample of 300 is ± 5.6%.

Executive Summary

Executive Summary

Natural Gas Safety Concerns

- The level of concern over natural gas safety in the home continues to be low., with over three-quarters of BC residents saying they are either not at all concerned (55%) or have never thought about (23%) it. As in previous waves, about one-in-five residents report being at least somewhat concerned (22%). Gas leaks and CO poisoning (each mentioned by 27% of residents) remain the main safety concerns.
- While the most and least important of nine potential safety issues have not changed over time, two of the top four issues have increased in importance since the last wave (i.e. rated 9 or 10 out of 10):
  - Knowing what to do when you detect a gas leak (81% vs. 73%);
  - Knowing about the dangers of CO poisoning (78% vs. 66%).
- The importance of the remaining top two issues has not changed significantly:
  - Knowing how to recognize a gas leak (75%);
  - Knowing how to use your gas appliances safely (67%).

Natural Gas Safety Knowledge

- Claimed knowledge of natural gas safety issues among BC residents is inline with historical levels. Seven-in-ten residents regard themselves as being at least somewhat knowledgeable on the subject. Males continue to rate themselves as more knowledgeable about safety than women and levels of knowledge tends to rise with income and education.
- Two-thirds of BC residents continue to be aware of the odour of natural gas. While the score has been consistent in 2012, it is significantly below the highs reached in three of the five waves in 2011. As in previous waves, most of these residents are able to describe the odour as either “rotten eggs” (66%) or “sulphur” (14%).
- About three-quarters (74%) of BC residents continue to recognize a natural gas leak from its smell, although only fifteen percent spontaneously compare the smell to “rotten eggs” or “sulphur”.

Executive Summary

Safety Preparedness

- Levels of safety preparedness have been resistant to change, at least in terms of residents being “extremely” (3%) or “very” (23%) prepared. The same is true on a year-over-year comparison. Both in 2011 and 2012, one-in-four respondents were either extremely or very prepared. There is a significant drop in the percentage of respondents classified as “not at all prepared” (54% vs. 60%) and a corresponding increase in those classified as “somewhat prepared” (21% vs. 15% in 2011).
- Likely responses to a natural gas leak in the home have also been consistent over time, with residents remaining less likely to evacuate the home (67%) than to contact a natural gas utility or emergency response provider (77%). At the same time, twice as many residents would evacuate the home immediately than would first call the appropriate organization (46% vs. 22%, respectively). One-in-four (41%) residents correctly identify the sequence of actions that should be taken, inline with historical levels.
- Residents continue to be more likely to get out of a house in response to a strong gas odour than to one that is slight (69% vs. 33%, respectively). The proportion who would do so in either circumstance, while not substantially higher than in previous waves, is nevertheless at record levels.
- As in previous waves, residents encountering a gas leak outdoors are almost twice as likely to call a natural gas utility or emergency response provider as they are to leave the area (81% vs. 43%, respectively).

Safe Excavation

- About four-in-ten BC residents remain at least somewhat prepared for safe excavation on their property, half of whom are “extremely” prepared. A majority of residents continue to be not all prepared (59%), not knowing where to find information about the location of underground utilities, who to contact before digging, or aware of BC One Call.
- Compared to year ago, however, the proportion of residents who are now extremely or very prepared has risen (29% vs. 20% in Wave 5, 2011), while fewer are not at all prepared (59% vs. 66%).
- Aided awareness of BC One Call increased substantially between Wave 2 and Waves 4 and 5 of 2012 (31% vs. 47%, respectively).

Executive Summary

Natural Gas Safety Behaviour

- Fourteen percent of BC residents report having a plan posted in their home of what to do in the event of a natural gas leak or an emergency. While directionally higher than last wave (8%), the difference is not statistically significant.
- One quarter (24%) of residents with children aged 6 to 18 in the household have discussed natural gas safety with them. As in previous waves, most of this information was related to fire or traffic safety, rather than to natural gas safety.

Public Safety Information Performance

- Just over half (55%) of residents rate their local natural gas company positively for informing the public about natural gas safety, inline with historical levels. However, the proportion who rate their gas company's performance as "excellent" has doubled compared to previous waves (19% vs. an average of 9% over the past 8 waves).

Natural Gas Safety Advertising Awareness

- Awareness of recent communications about natural gas safety has increased to one-third (32%) of BC residents from one-fifth last wave (21%), and is at its highest level since the first wave of tracking in 2011. Combined with the fact that more residents than ever credit FortisBC as the sponsor of this communications (71%) and radio as the source (46%), this is an indication that the current radio campaign has had an impact.
- The main message most often associated with recent safety communications continues to be related to one of the Fall campaign themes (i.e. if you smell gas, get out/help).
- Awareness of recent FortisBC advertising continues to increase, rising steadily from just twenty-seven percent in Wave 2 of 2012 to forty-one percent currently.
- Recall of the radio ad related to safety preparedness ("If you smell gas, get out") has stabilized at half of all residents, most of whom recall the ad clearly (38%) rather than just vaguely (12%). Recall of the ad promoting safe excavation, which ran fewer flights over a briefer advertising cycle, has declined somewhat (30% vs. 38% in Wave 4, 2012), and this ad is as likely to be recalled vaguely as clearly. As in the last wave, residents of the Interior have lower recall of the safety preparedness ad compared to those in other regions, as do females compared to males.

Executive Summary

Conclusions and Recommendations

- FortisBC’s safety campaign has achieved significant reach and recall levels among BC residents.
  - At the conclusion of the 2012 Fall campaign, recall of gas safety communications and awareness of FortisBC advertising were at their highest level since the beginning of tracking, in April of 2011.
  - Half of all BC residents have aided awareness of the radio ad related to natural gas leaks, most of them recalling the ad clearly, although female residents and those in the Interior tend to have lower awareness.
  - The Spring radio tags appear to have been less effective than the Fall radio ads. The tags did not increase awareness of either natural gas safety communications in general, or of FortisBC safety advertising in particular. However, they might have contributed to a slight improvement in safety preparedness (i.e. following the radio tags, there was a modest increase in the number of residents who were at least “somewhat” prepared).

- The survey results also suggest that FortisBC’s latest public safety campaign has had some positive impacts on BC residents’ perceptions and knowledge of natural gas safety.
  - While the campaign does not appear to have increased levels of safety knowledge or concern about natural gas safety in the home, it does appear to have contributed to an increase in the perceived importance of knowing what to do when you detect a gas leak.
  - There has been some improvement in levels of safety preparedness, with residents being more likely to be at least “somewhat” prepared and less likely to be “not at all prepared”.
  - Residents are also somewhat more likely to take appropriate action in the event of slight or strong gas odours in the house than they were at the beginning of the campaign.
  - More residents are now extremely or very prepared for safe excavation on their property than before, and fewer are not at all prepared.

Executive Summary

Conclusions and Recommendations

- Awareness of BC One Call increased substantially between Wave 2 and Waves 4 and 5 (which could be attributed to the Fall radio campaign).
- Residents are significantly more likely to rate their gas company's performance on informing the public about natural gas safety as "excellent" than previously.

- Relative to last year, FortisBC's 2012 safety campaign appears to have had a positive cumulative effect on levels of both safety preparedness and safe excavation preparedness.
  - Residents are less likely to be completely unprepared for either safety situation in 2012 than they were during 2011.

Safety Preparedness Index

Safety Preparedness Segments

Survey respondents segmented into four groups, depending on their level of "preparedness" for a natural gas leak. The four segments are defined as follows:

Extremely Prepared

- Included in this group are respondents who correctly answer either all four questions or all questions for which they qualify to answer. Historically, fewer than five percent of respondents qualify for this group.

Very Prepared

- Respondents who correctly answer the following questions fall into this segment. This group typically represents between one-fifth and one-quarter of respondents.
  - Know the gas smell [QA9a] or Recognize a gas leak [QA10] (i.e. rotten eggs or sulphur)
  - Know what to do first (get out of the house) [QA11]
  - Know who to call (911/Gas company/FortisBC/Terasen Gas) [QA12]

Somewhat Prepared

- Respondents who correctly answer the following questions qualify for this segment. This group typically represents between less than one-quarter of respondents.
  - Know the gas smell [QA9a] or Recognize a gas leak [QA10] (i.e. rotten eggs or sulphur)
  - Know who to call (911/Gas company/FortisBC/Terasen Gas) [QA11 or QA12]

Not at All Prepared

- All remaining respondents are included in this segment, which generally comprises the majority of total respondents.

Safety Preparedness Index

	2011	2012	2012				
	YTD	*YTD*	Wave 1	Wave 2	Wave 3	Wave 4	Wave 5
Base (All respondents)	**1502** **%**	**1503** **%**	300 %	300 %	301 %	302 %	300 %
Preparedness Indicators							
1. Know the gas smell (rotten eggs or sulphur) [A9a & A10]	**47**	**60**	58	55	62	63	60
2. Know what to do first (get out of the house) [A11]	**40**	**46**	49	44	46	42	46
3. Know who to call (911/gas company/FortisBC/Terasen Gas) [A12] Top row: 2nd mentions only/*Bottom row: 1st & 2nd mentions*	**50** *74*	**56** *75*	53 *71*	56 *75*	59 *79*	52 *72*	61 *77*
4. Have gas emergency plan posted [A16]	**10**	**11**	13	10	10	8	14
Preparedness Groups							
Extremely Prepared	**2**	**2**	3	1	2	2	3
Very Prepared	**24**	**23**	22	22	26	23	23
Somewhat Prepared	**15**	**21**	15	23	21	25	20
Not At All Prepared	**60**	**54**	60	55	51	51	54

= Significantly higher than in 2011 (circle)

= Significantly lower than in 2011 (box)

Safe Excavation Index

Safe Excavation Segments

Survey respondents are segmented into four groups, depending on their level of "preparedness" for a safe excavation. The four segments are defined as follows:

Extremely Prepared

- Know information about where underground utilities are located is available [QA18] + know you have to contact someone before digging [QA20a] + know who should be contacted (either FortisBC or BC One Call) [QA20b] + aware of BC ONE CALL [QA19/QA20b/QA20/QA21/QA22].

Very Prepared

- Know information about where underground utilities are located is available + know you have to contact someone before digging + DON'T know who to contact or answer incorrectly + aware of BC ONE CALL.

Somewhat Prepared

- Know information about where underground utilities are located is available + know you have to contact someone before digging + DON'T know who to contact or answer incorrectly + NOT aware of BC ONE CALL.

Not at All Prepared

- None of the above

Safe Excavation Index

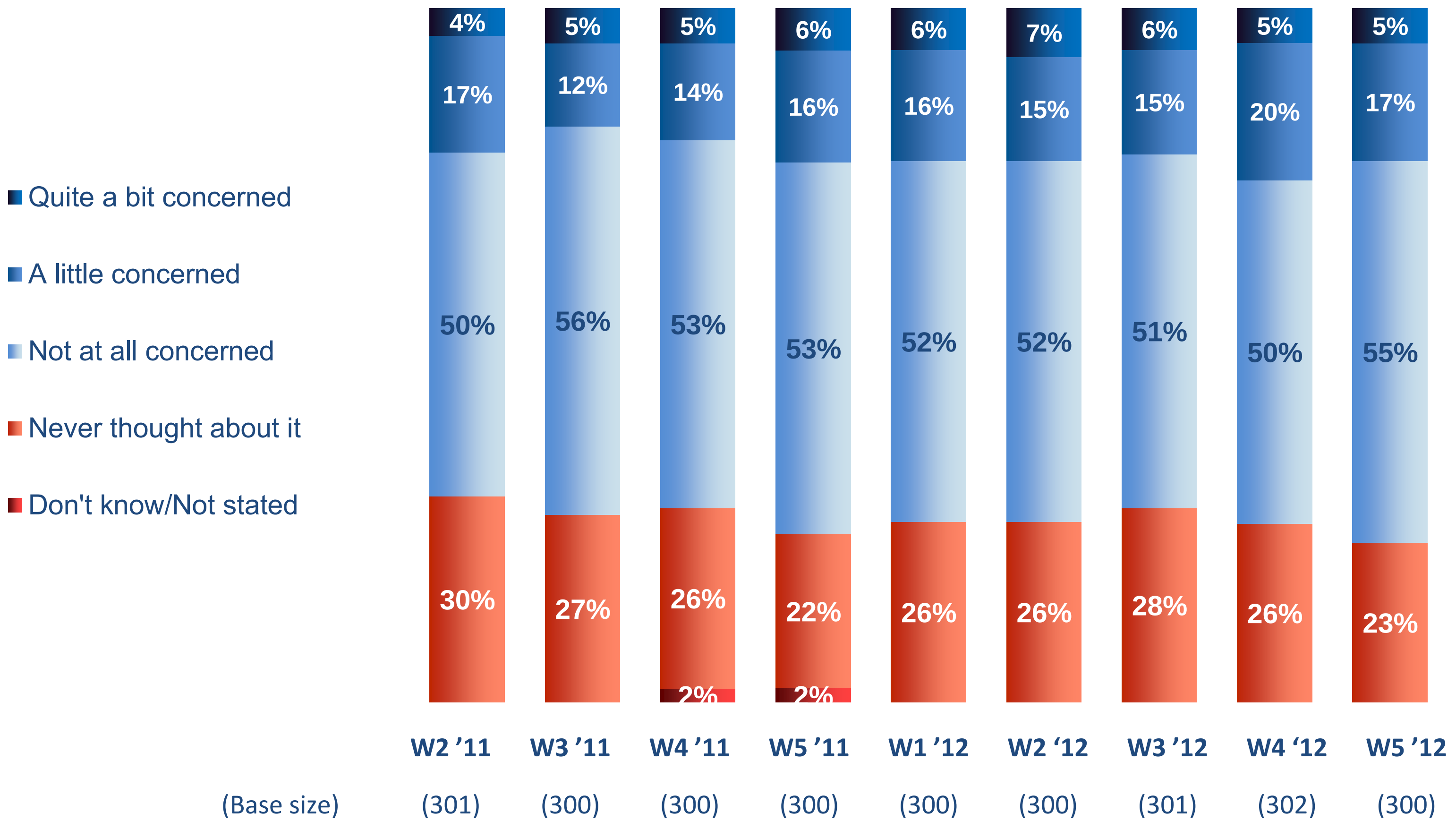
	2011			2012				
	Wave 4	Wave 5	YTD	Wave 2	Wave 3	Wave 4	Wave 5	YTD
Base (All respondents)	300 %	300 %	**600** **%**	300 %	301 %	302 %	300 %	**1203** **%**
Preparedness Groups								
Extremely Prepared	16	12	**14**	9	14	15	21	**15**
Very Prepared	6	8	**7**	9	9	12	8	**9**
Somewhat Prepared	11	14	**13**	22	12	16	12	**15**
Not At All Prepared	67	66	**66**	61	65	57	59	$\boxed{\textbf{61}}$

= Significantly lower than in 2011

Natural Gas Safety Concerns

Concern About Natural Gas Safety

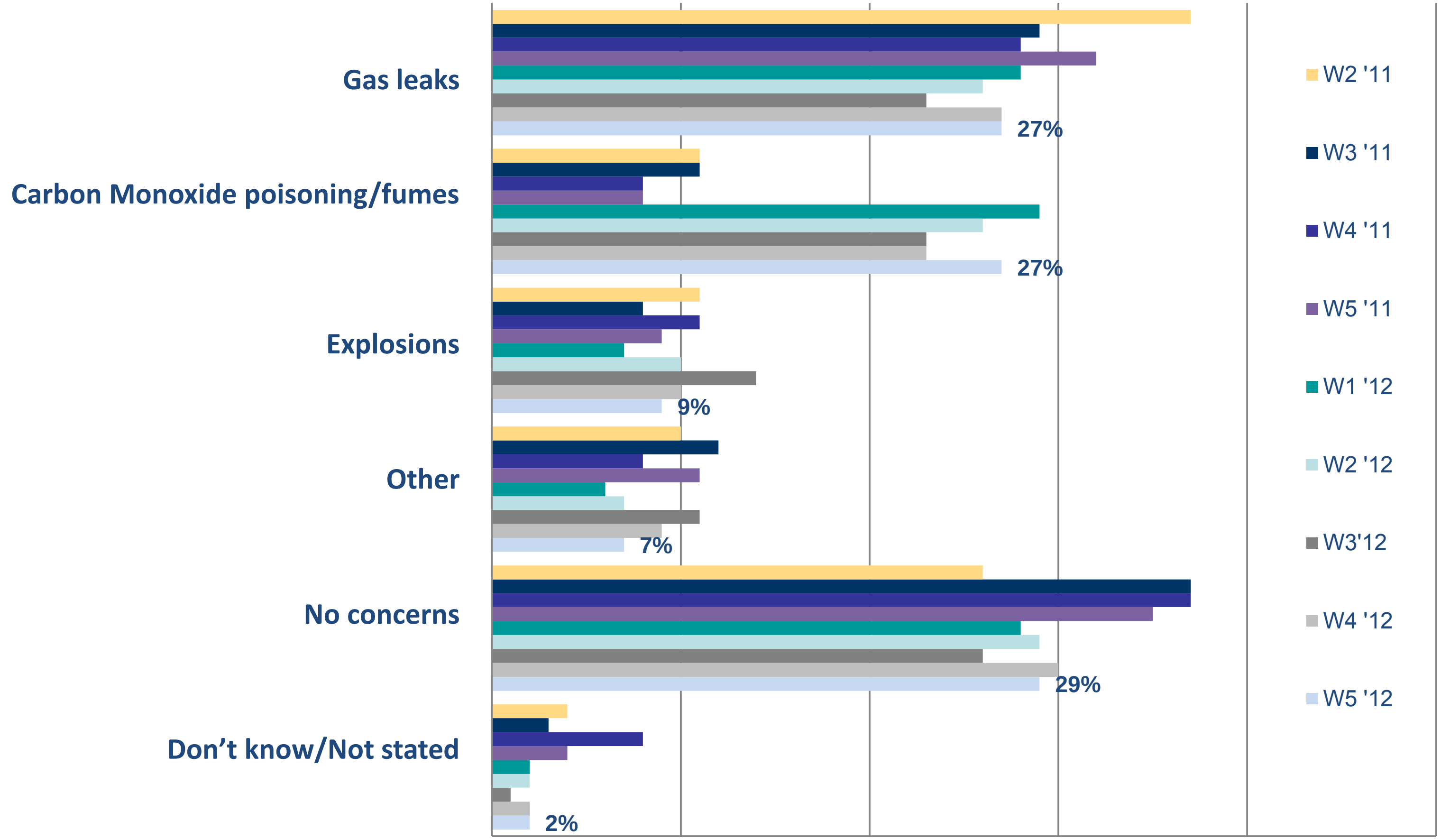
- Levels of concern over the safe use of natural gas in the home has been stable over time, with no significant changes registered throughout the tracking period.
- A large majority of residents are either unconcerned about natural gas safety (55%) or have never given it any thought (23%). Less than one-quarter are at least "a little" concerned about natural gas safety.



A4 I'd like you to tell me how concerned you are about the safety of using natural gas in the home. Would you say you are…?
Base: All respondents

Safety Concern

- Residents remain most concerned about gas leaks and CO poisoning when it comes to using natural gas in the home (mentioned by 27% each).
- Three-in-ten residents continue to have no particular concerns about natural gas use in the home.



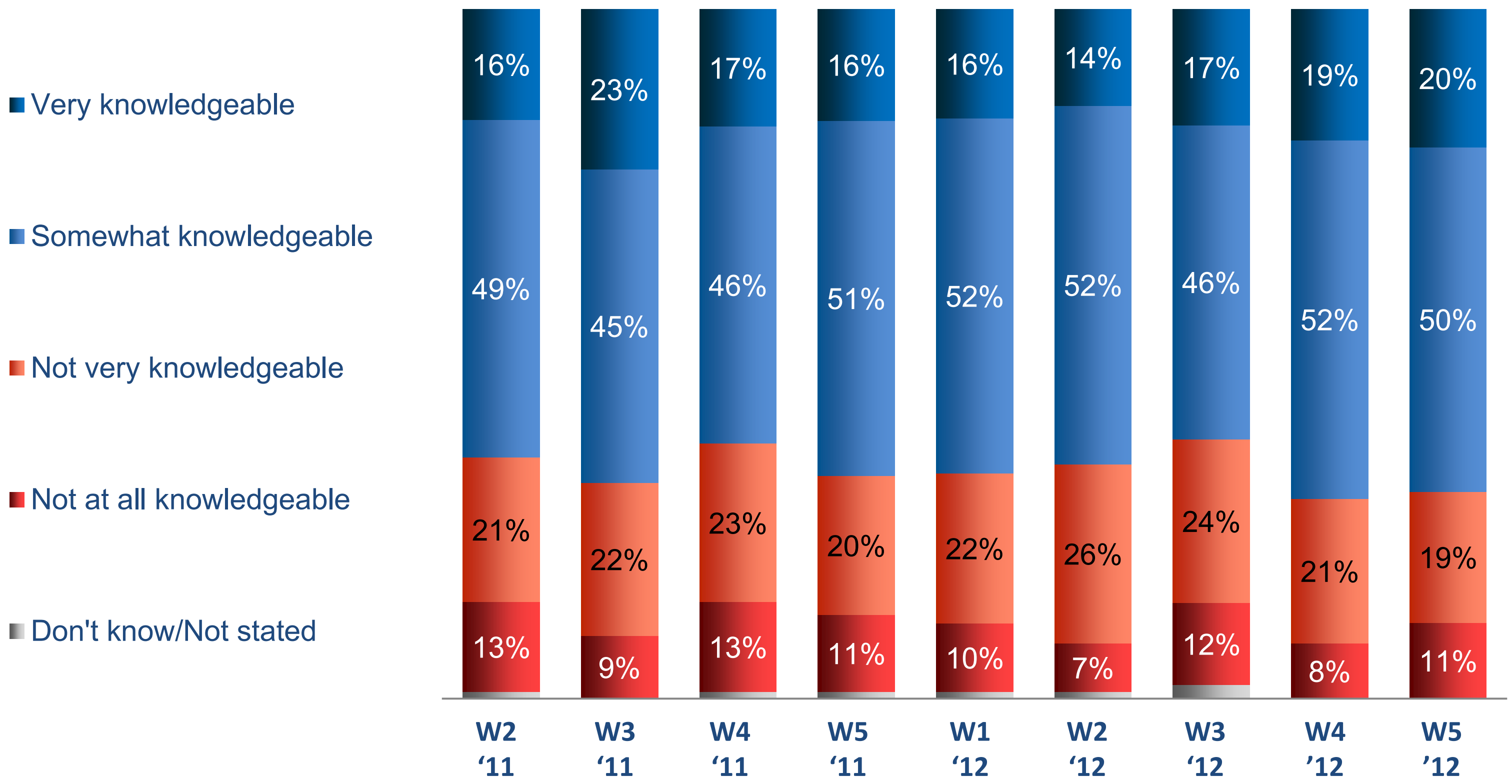
A5 What would you say is your single greatest safety concern regarding the use of natural gas in homes?

Base: All respondents (W2 '11: n=301; W3 '11: n=300; W4 '11: n=300; W5 '11: n=300; W1 '12: n=300; W2 '12: n=300; W3 '12: n=301; W4'12: n=302; W5 '12: n=300)

Natural Gas Safety Knowledge

Knowledge About Natural Gas Safety

- Levels of natural gas safety knowledge are unchanged since last wave and inline with the historical trend. Currently, seven-in-ten residents claim to be at least somewhat knowledgeable.
- Males continue to more likely than females to rate themselves as "very knowledgeable" on the subject (29% vs. 12%, respectively). Claimed knowledge also tend to rise with income and education levels.



(Base size) (301) (300) (300) (300) (300) (300) (301) (302) (300)

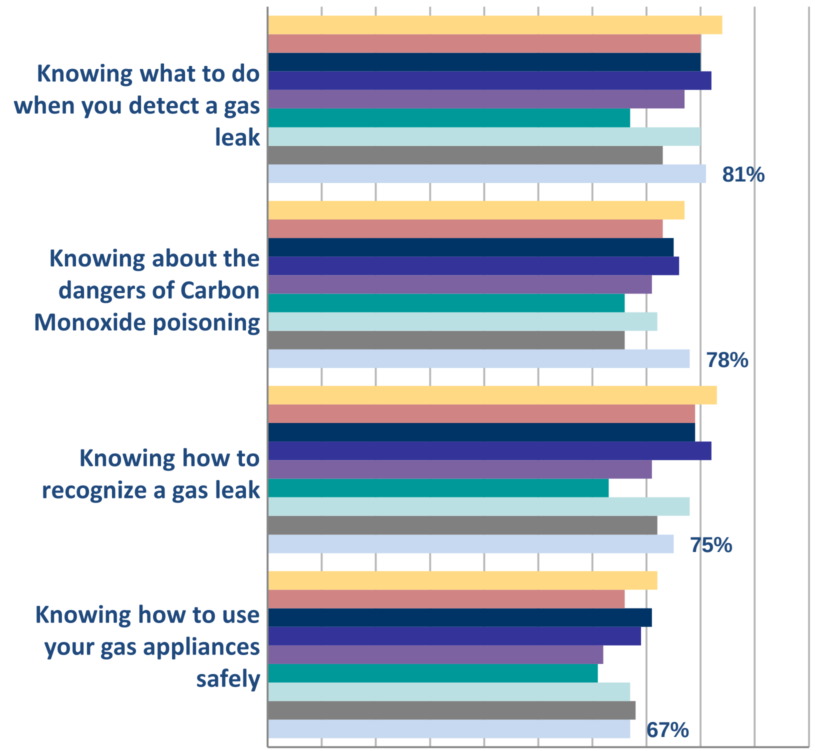
A6 How knowledgeable do you feel you are about issues surrounding natural gas safety? Would you say you are…

Base: All respondents

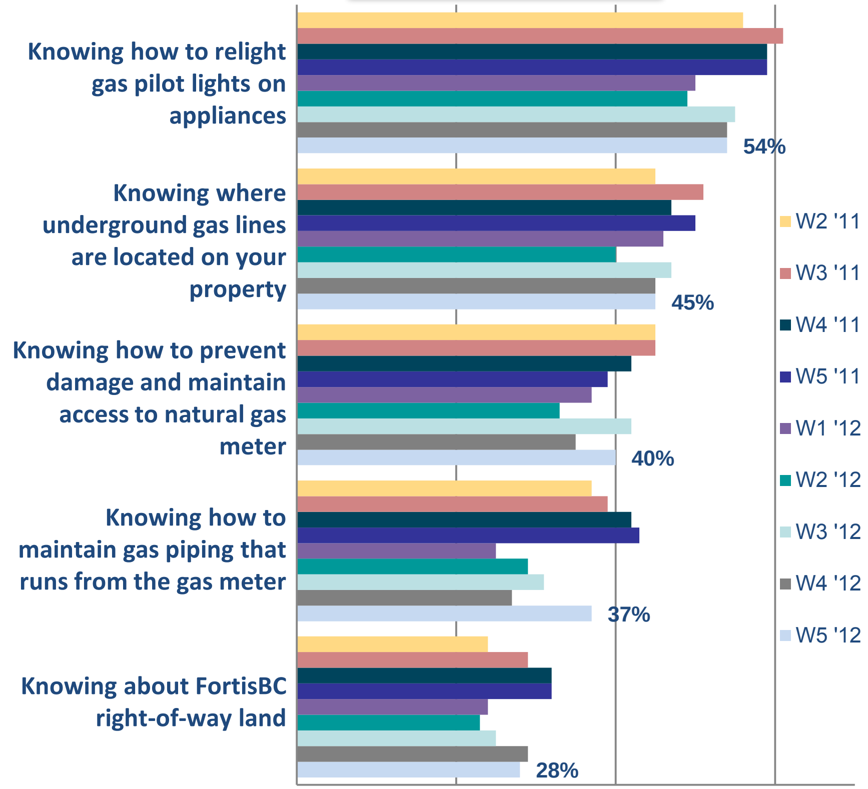
Importance Of Specific Safety Issues

- Of nine safety issues evaluated, the most and least important to residents remain unchanged although levels of concern for some issues appear to have risen.
- Since Wave 4, "top box" importance ratings (i.e. 9 or 10 out of 10) have increased for two of the top four issues: "knowing what to do in the event of a gas leak" (81% vs. 73%, respectively) and "knowing about the dangers of CO poisoning" (78% vs. 66%). Among the bottom five issues, perceived importance of "knowing how to maintain gas piping" is also higher (37% vs. 27%).

Top Four Issues



Bottom Five Issues

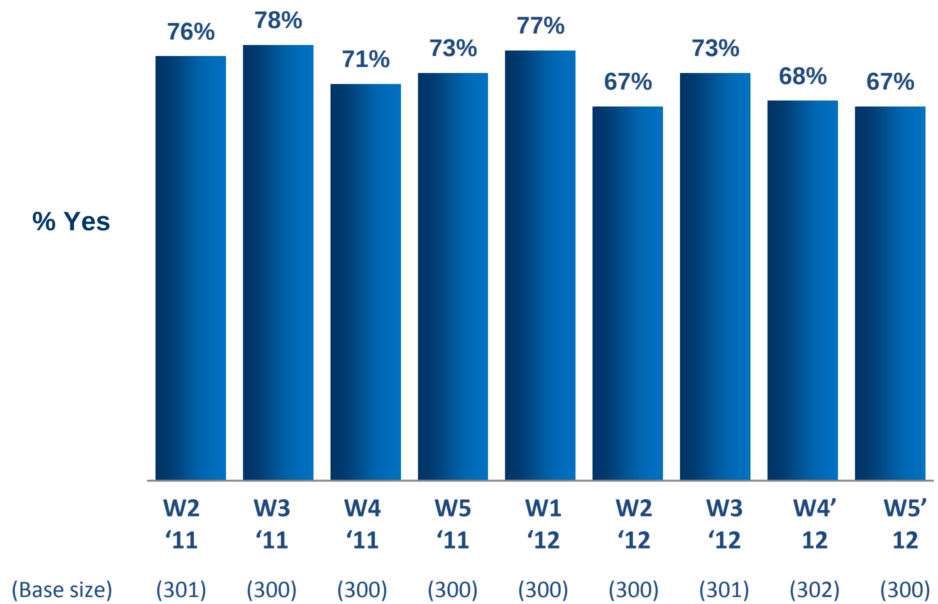


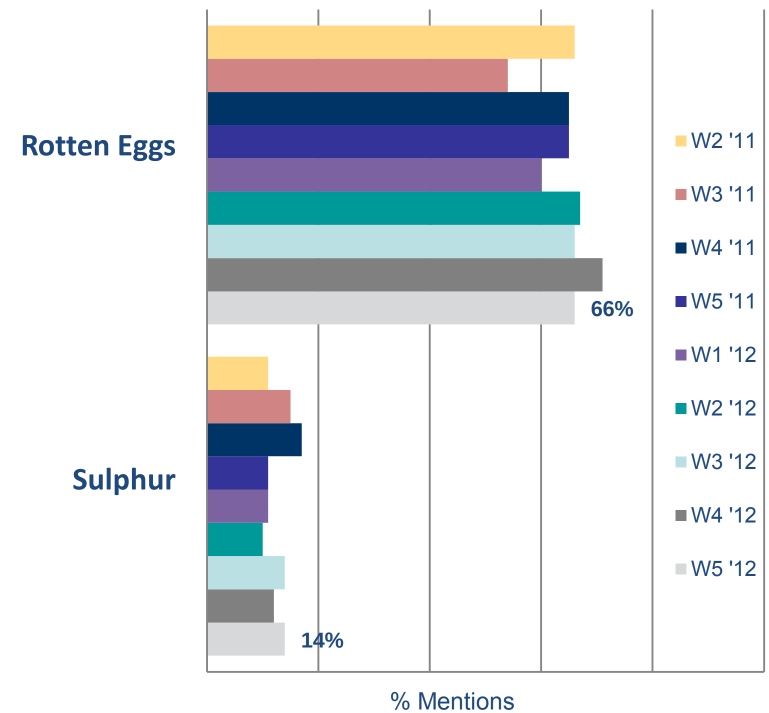
A7 On a scale of "1" to "10" with "1" being "Not at all important" and "10" being "Extremely important, how important are the following safety issues to you and your family?

Base: All respondents (W2 '11: n=301; W3 '11: n=300; W4 '11: n=300; W5 '11: n=300; W1 '12: n=300; W2 '12: n=300; W3 '12: n=301; W4 '12: n=302; W4 '12: n=300; W5 '12: n=300)

Natural Gas Smell

- Two-thirds of BC residents say they are aware of the odour of natural gas, consistent with historical levels, although generally lower than the scores in 2011.
- A large majority of residents who are aware of the odour continue to describe it as either "rotten eggs" (66%) or "sulphur" (14%).





A8 Thinking about the natural gas piped into your home, are you aware of any smell or odour that natural gas might have or contain?

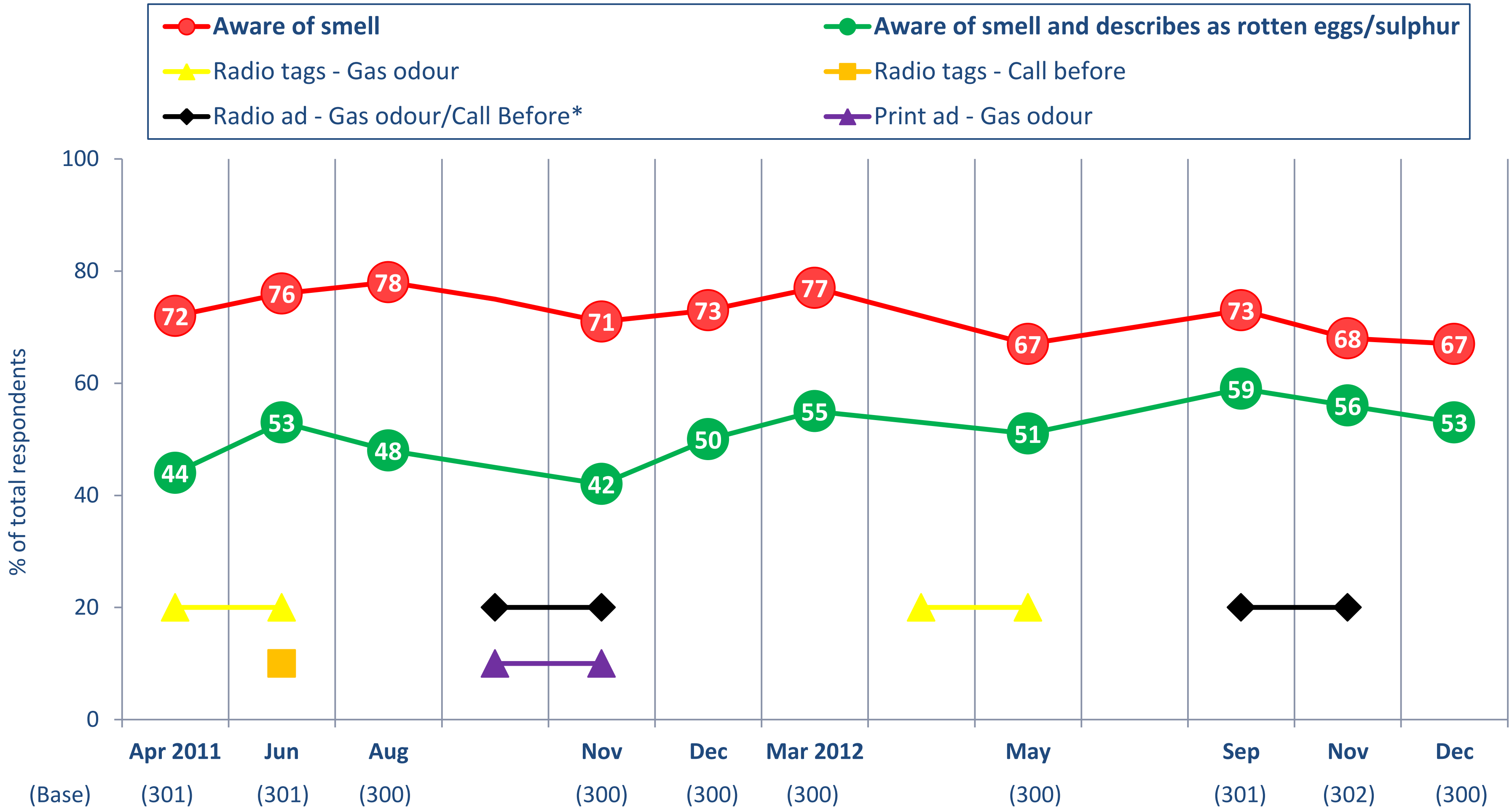
Base: All respondents

A9 And how would you describe the smell?

Base: Those aware of natural gas smell (W2 '11: n=221; W3 '11: n=231; W4 '11: n=217; W5 '11: n=215; W1 '12: n=227; W2 '12: n=199; W3 '12: n=212; W4'12: n=201; W5 '12: n=197)

Natural Gas Smell

- The following graph shows the trend in awareness of the odour of natural gas and unaided use of rotten eggs or sulphur to describe the smell, as well as the timing of FortisBC safety campaigns.



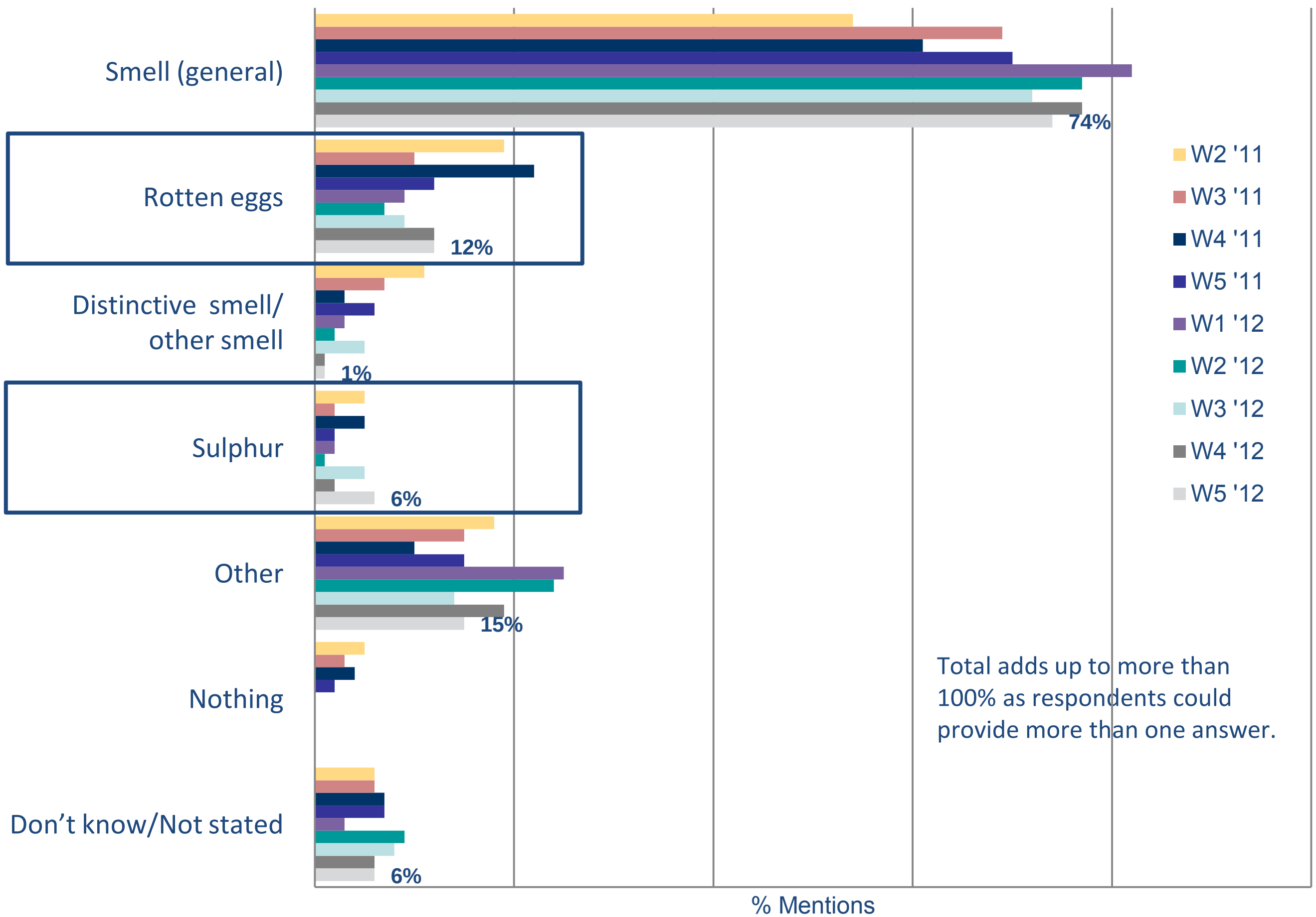
A8 Thinking about the natural gas piped into your home, are you aware of any smell or odour that natural gas might have or contain?

A9 And how would you describe the smell?

* Fall 2011 radio campaign included "Gas Odour" ads only

Recognition Of Natural Gas Leak

- Three-quarters (74%) of BC residents are aware that natural gas leaks can be detected by their smell. However, only 15% correctly identify the smell as either "rotten eggs" or "sulphur". While these results are consistent with historical norms, use of the latter term has increased slightly since the last wave (6% vs. 2%, respectively).
- These terms continue to be more commonly applied to the odour of natural gas than to describe a natural gas leak.

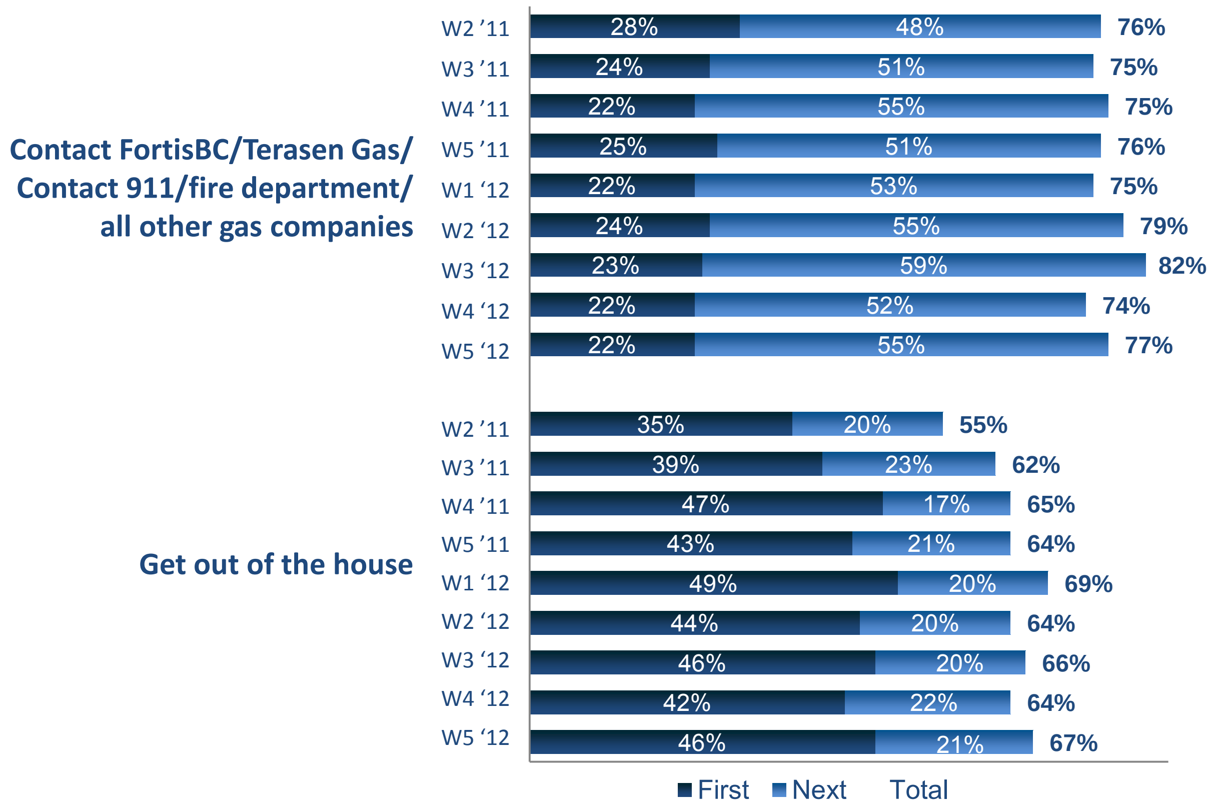


A10 Next, we'd like to ask some questions about what you would do if there was a natural gas leak. First of all, how would you recognize a natural gas leak?

Base: All respondents (W2 '11 – W2 '12: n=300; W3 '12: n=301; W4'12: n=302; W5 '12: n=300)

Actions If Natural Gas Leak Is Suspected At Home

- Response to a natural gas leak in the home has not changed significantly. As in previous waves, just under half (46%) of BC residents say the first thing they would do in such an event is to get out of the house, while one-in-five would do so next.
- A large majority of residents continue to be most likely to contact a natural gas utility or emergency response (77%), but less likely to do so first (22%) than to get out of the house.



A11 And what would you do first if you were aware of a natural gas leak in your home or someone else's home?

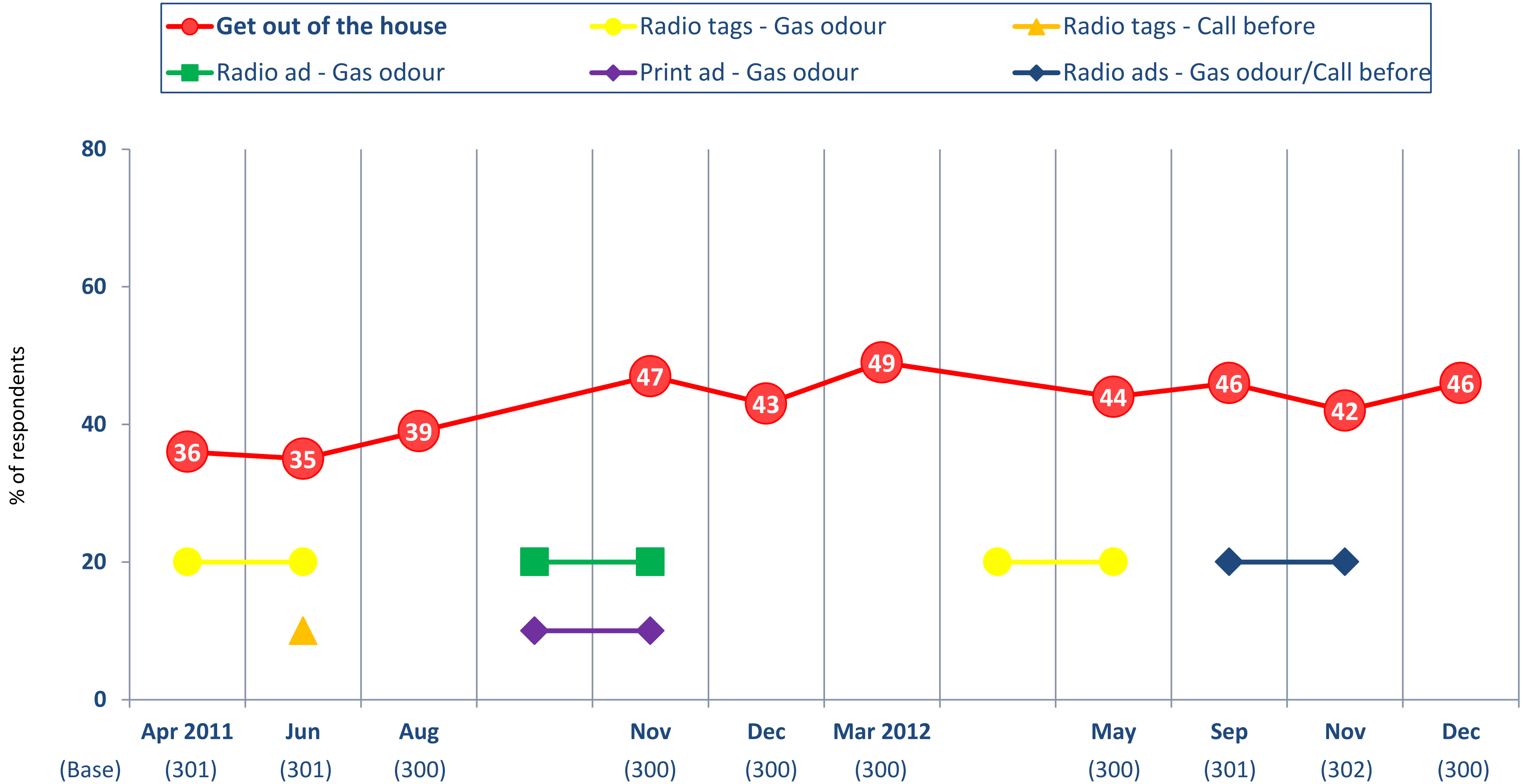
A12 And what would you do next?

Base: All respondents (W2 '11: n=301; W3 '11: n=300; W4 '11: n=300; W5 '11: n=300; W1 '12: n=300; W2 '12: n=300; W3 '12: n=301; W4 '12: n=302; W5 '12: n=300)

What To Do First If Natural Gas Leak Is Suspected

- The following graph shows the trend in the proportion of BC residents who correctly identify "getting out of the house" as the first action they would take in the event of a natural gas leak in the home, together with the timing of FortisBC's safety campaigns.

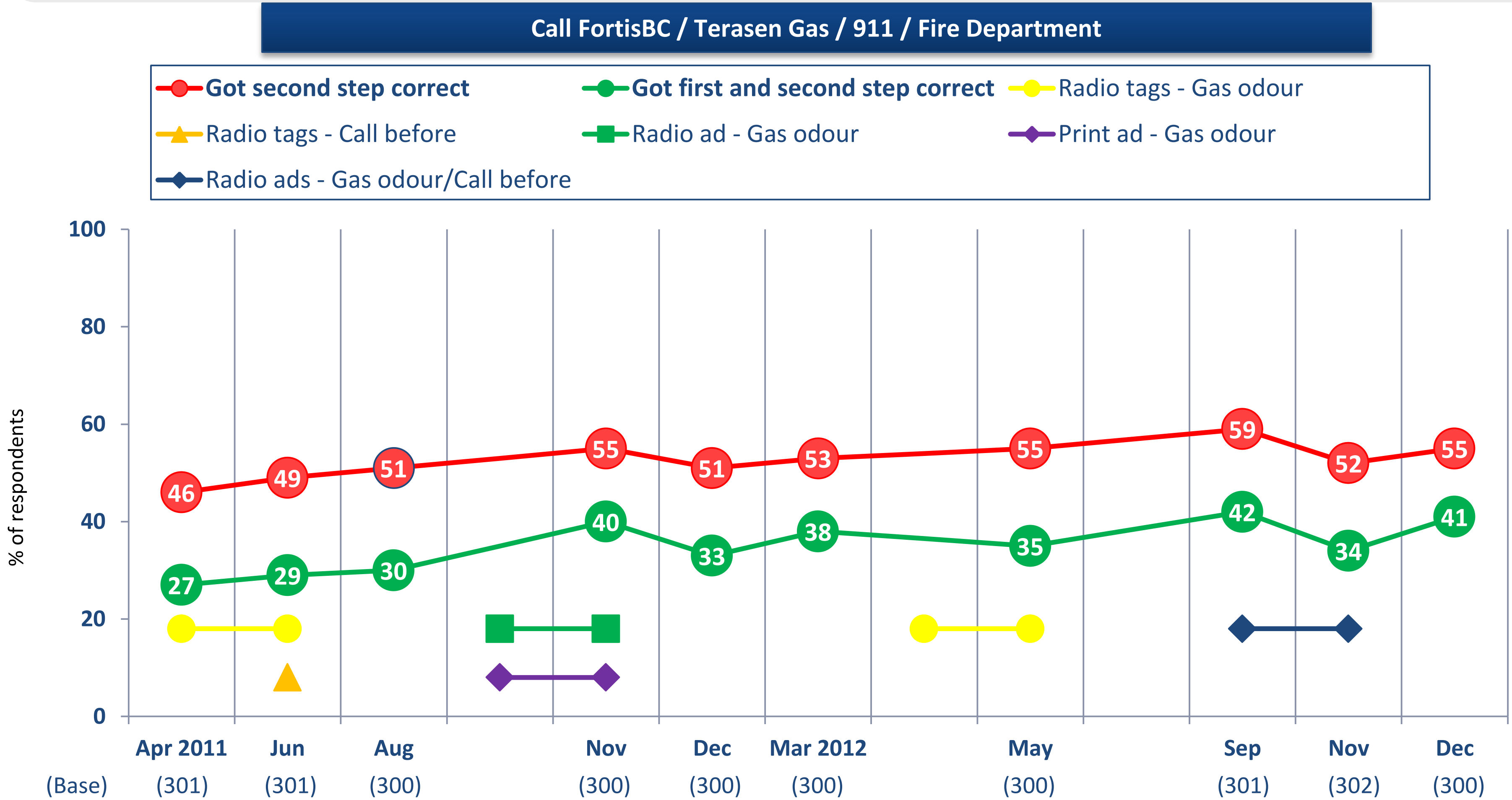
Get Out of the House



A11 *And what would you do first if you were aware of a natural gas leak in your home or someone else's home?*

What To Do Next If Natural Gas Leak Is Suspected

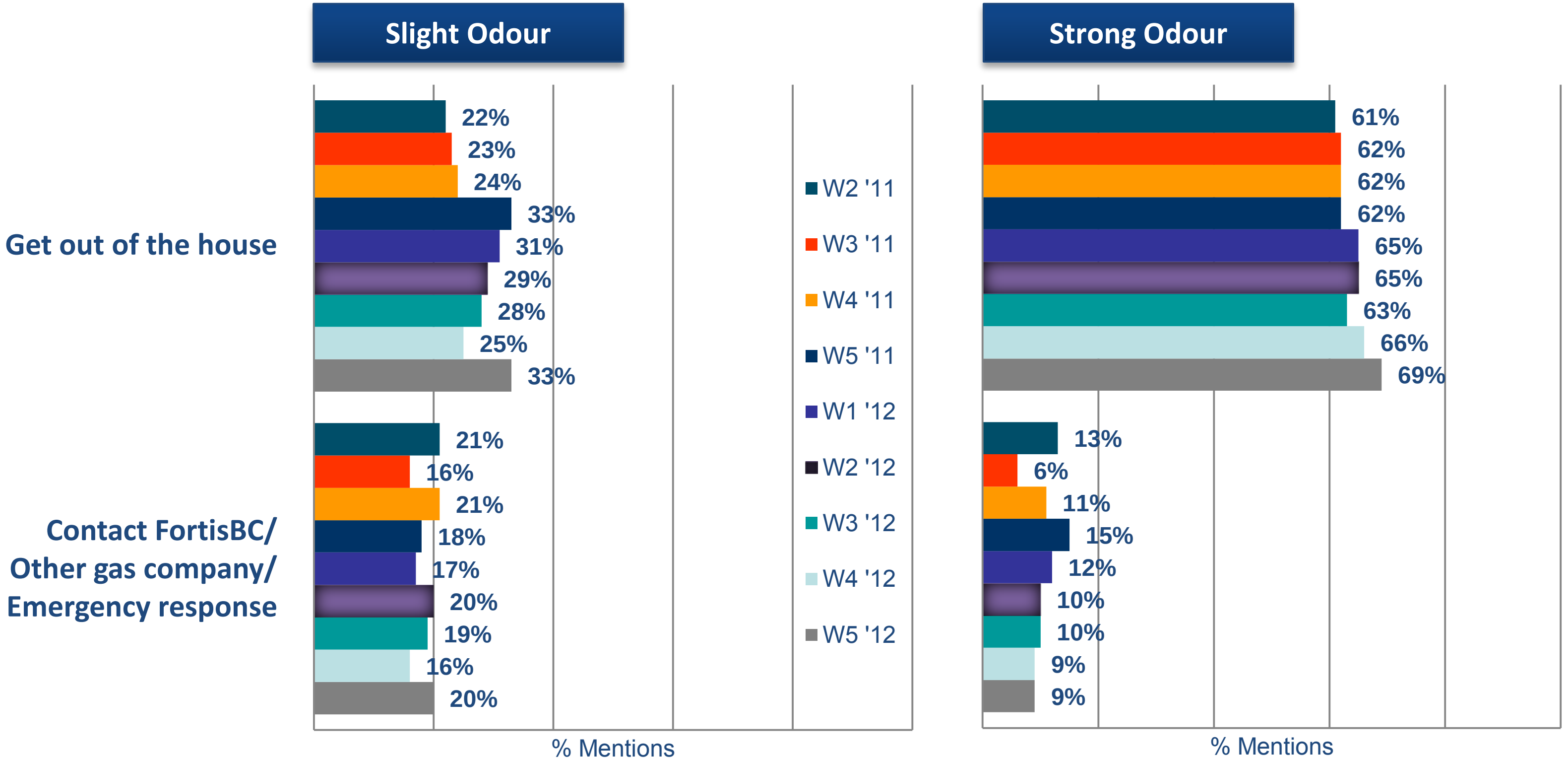
- The following graph shows the trend in awareness of the appropriate sequence of actions to take in the event of a natural gas leak in the home, as well as the timing of FortisBC safety campaigns.
- About four-in-ten (41%) residents correctly identify the sequence of actions that should be taken when a natural gas leak occurs (i.e. get out of the house; contact gas co./emergency response), consistent levels since November, 2011.



A12 *And what would you do next?*

Actions If Strong/Slight Gas Odour Detected At Home

- Residents continue to be much more likely to leave their home first if confronted with a strong gas odour than if faced with one that is slight. Over two-thirds (69%) would evacuate in the event of a strong gas odour compared to one-third who would do so if they detected a slight gas odour. However, the proportion who say they would get out of the house given a slight odour has increased since the last wave (33% vs. 25%, respectively).
- Conversely, residents remain more likely to contact a natural gas utility or emergency response provider first in the event of a slight odour compared to one that is strong (20% vs. 9%, respectively).

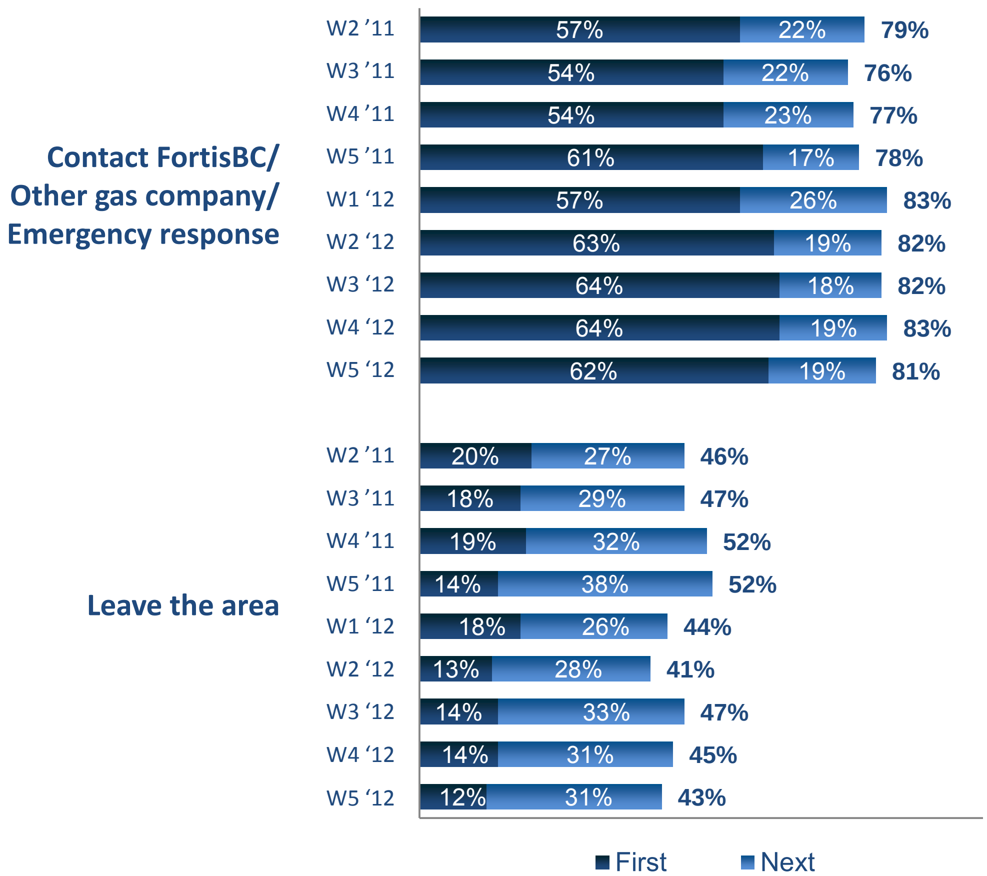


A13a If you were at home and there was a slight gas odour, what would you do first?
A13b If you were at home and there was a strong gas odour, what would you do first?

Base: All respondents (W2 ‘11: n=293; W3 ‘11: n=297; W4 ‘11: n=289; W5 ‘11: n=293; W1 ‘12: n=300; W2 ‘12: n=300; W3 ‘12: n=301; W4 ‘12: n=302; W5 ‘12: n=300)

Actions If Natural Gas Leak Is Suspected Outdoor

- Consistent with previous waves, BC residents are much more likely to contact a natural gas utility or emergency response provider (81%) than to leave an outdoor area (43%) if they encountered a natural gas leak. Few (12%) say they would leave the area first.



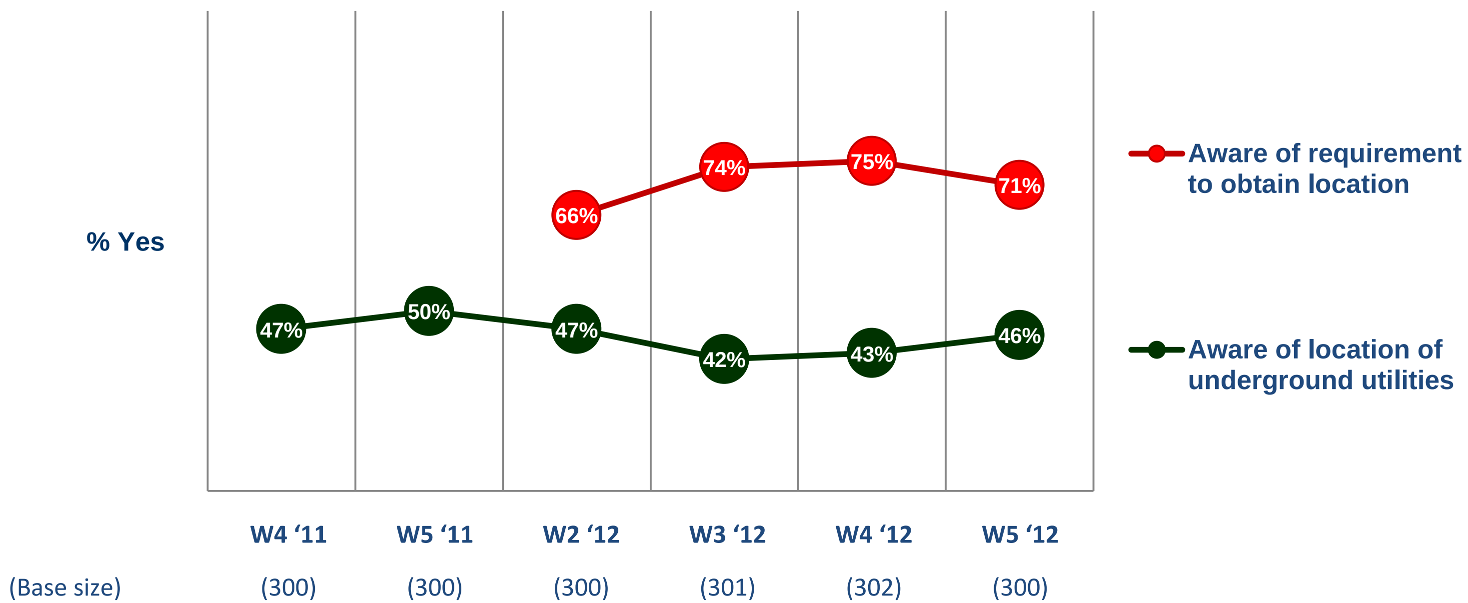
A14/15 What if you were in an outdoor area away from your home, such as walking along the street or in a park, and you thought there was a natural gas leak, what would you do first? And what would you do next?

Base: All respondents (W2 '11: n=301; W3 '11: n=300; W4 '11: n=300; W5 '11: n=300; W1 '12: n=300: W2 '12: n=300; W3 '12: n=301; W4 '12: n=302; W5 '12: n=300)

Excavation Safety Knowledge

Underground Utilities Location

- Just under half (46%) of BC residents claim to know the location of underground utilities on their property, inline with historical levels.
- Certain demographic groups continue to claim greater knowledge, including residents of the Interior and Island relative to the Lower Mainland, as well as males and homeowners compared to females and renters.
- Awareness of the legal requirement to obtain the location of underground natural gas lines prior to digging is also consistent with previous wave. Currently, about seven-in-ten (71%) residents claim to be aware of this requirement.



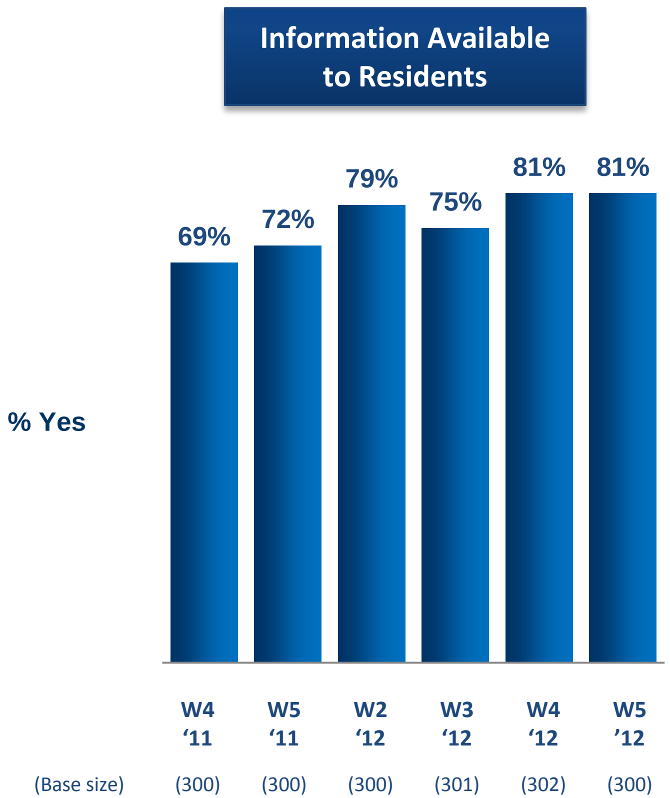
A17 If you lived in a house and were landscaping, gardening, installing a sprinkler system or putting in fence posts, would you know where your underground utilities are?

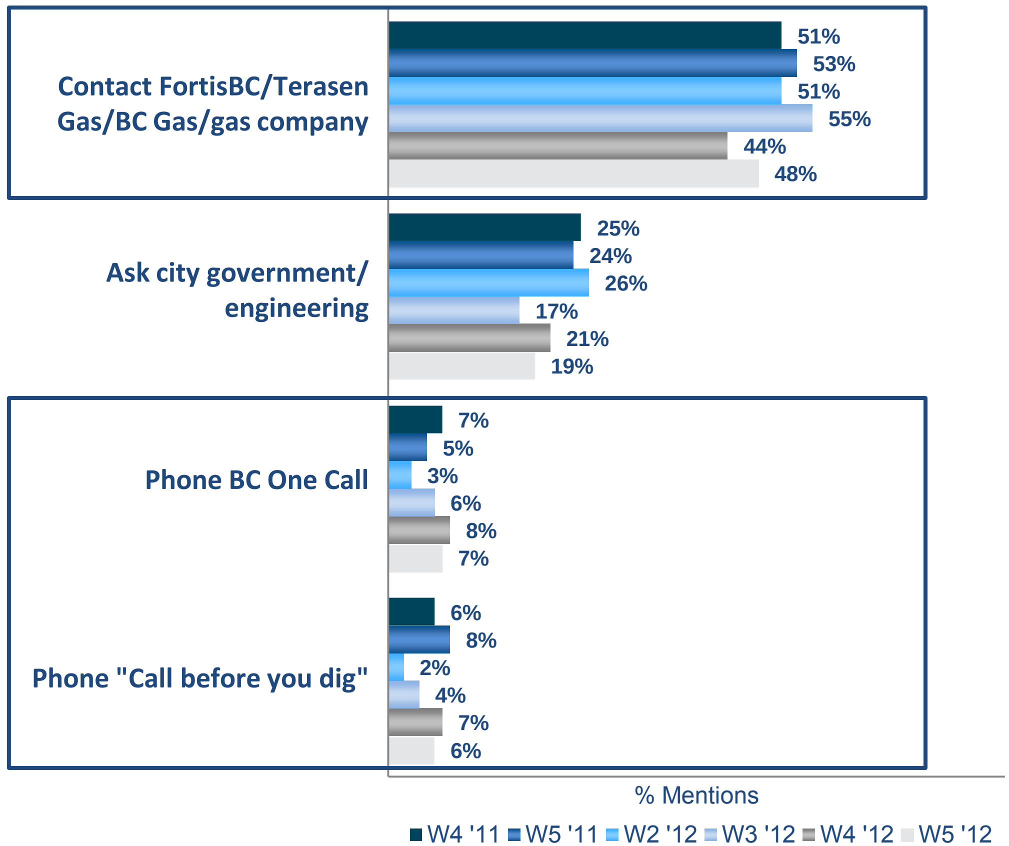
A17a To the best of your knowledge, does the law require you to obtain the location of the underground natural gas line before digging on your property?

Base: All respondents

Underground Natural Gas Information

- As in previous waves, a large majority (81%) of BC residents believe information about the location of underground utilities on their property is available to them.
- Following a decline last Wave, the proportion of residents who claim they would contact their natural gas company to obtain this information consistent with historical levels (48%). One-in-five residents would contact their city (19%), while fewer say they would phone BC One Call (7%) or "Call Before You Dig" (6%).





A18 As far as you know, is this information available to residents?

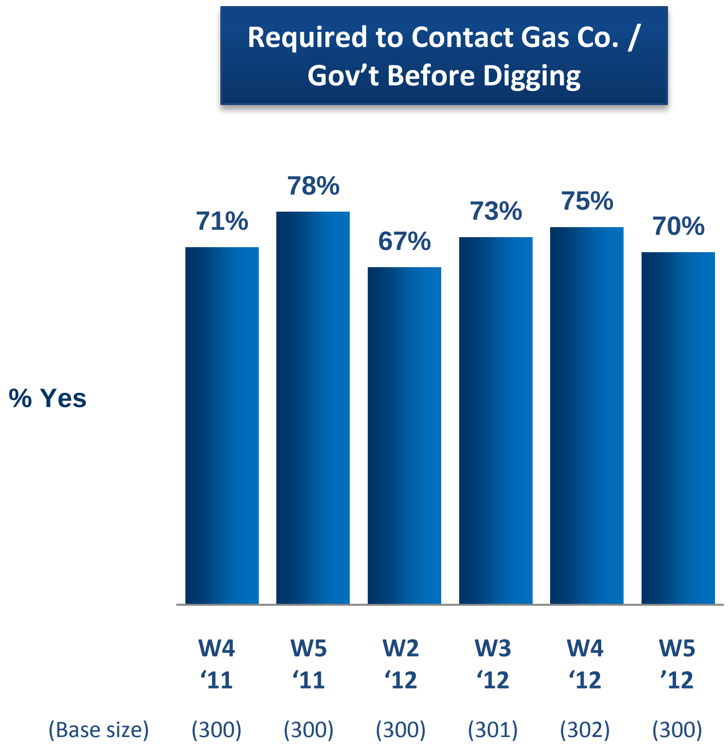
Base: All respondents

A19 How would you find out where the underground natural gas line is?

Base: Those aware information is available (W4 '11: n=208; W5 '11: n=219; W2 '12: n=235; W3 '12: n=229; W4 '12: n=248; W5 '12: n=245)

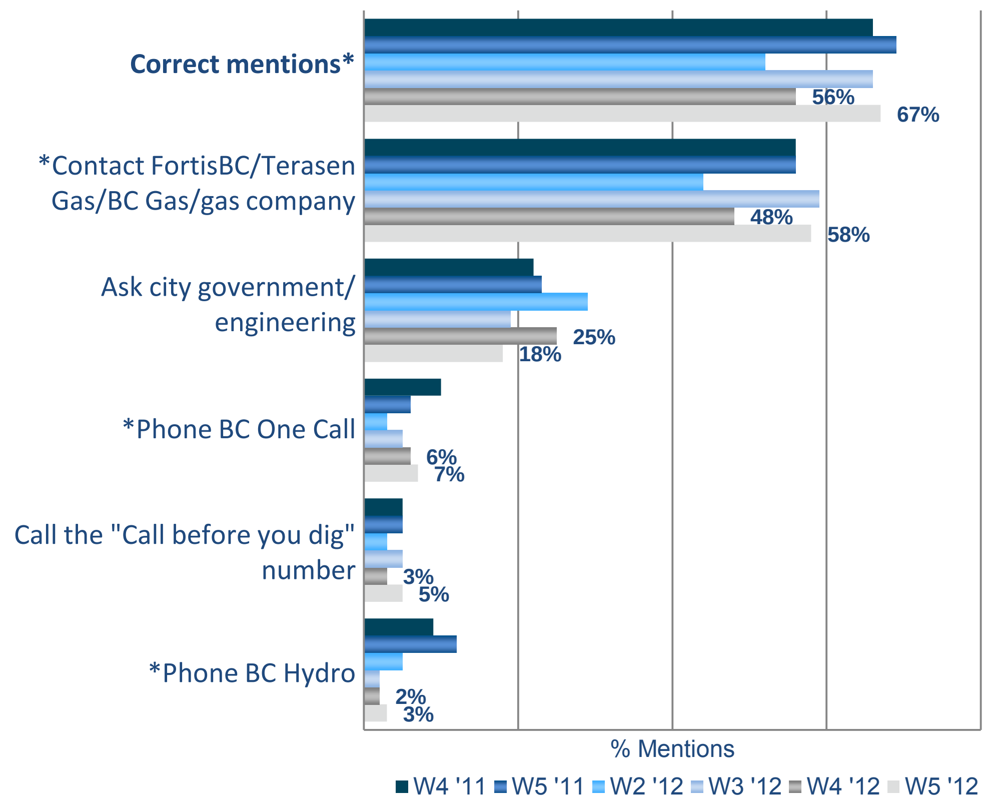
Underground Natural Gas Information

- Seven-in-ten BC residents are aware of the requirement to contact their natural gas utility or government organization before digging on their property. This is consistent with historical levels as well as with levels of awareness of the legal requirement to obtain the location of underground natural gas lines before digging (71%).
- Two-thirds of residents who are aware of the need to contact their gas utility or government correctly identify the company or government agency they should contact prior to digging (FortisBC/gas company, BC One Call, BC Hydro). While this represents an increase over the last wave (67% vs. 48% In Wave 4, 2012), it is inline with the historical norm.



A20a As far as you know, are you required to contact your natural gas company or government organization before you start digging or excavating in your yard?

Base: All respondents

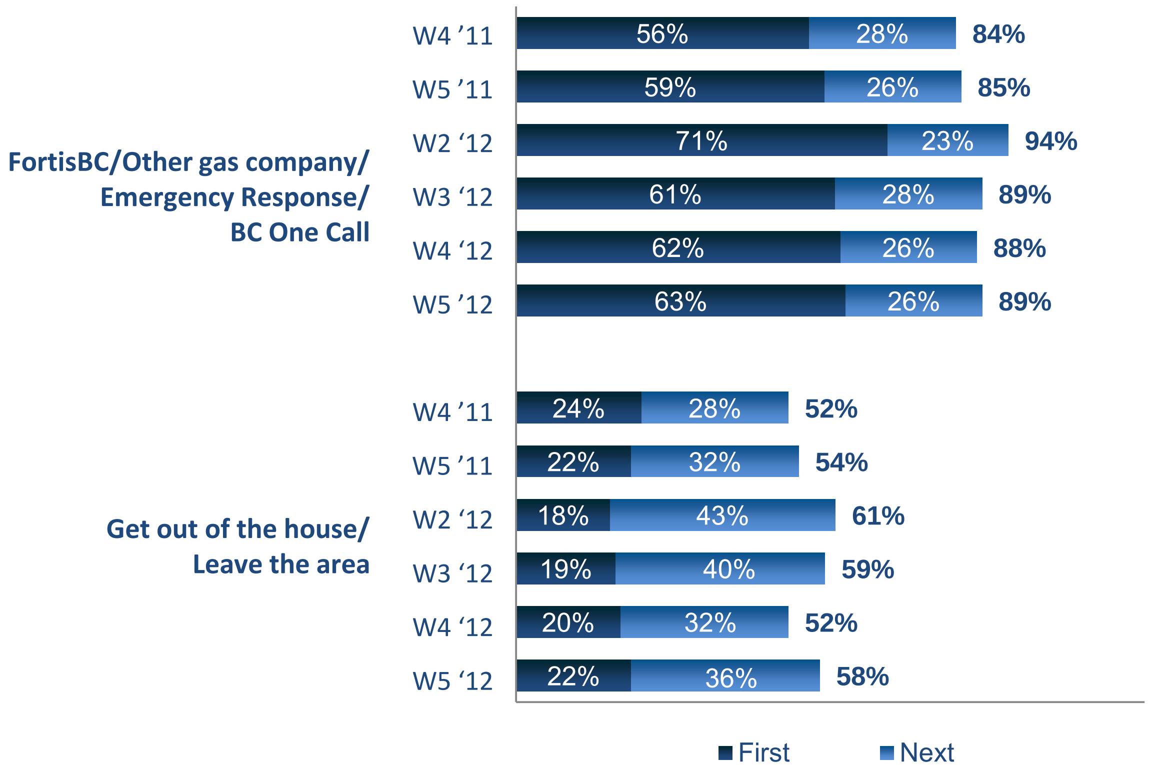


A20b Who should you contact before you start digging or excavating in your yard?

Base: Those who know to contact someone before digging (W4 '11: n=210; W5 '11: n=232; W2 '12: n=194; W3 '12: n=220; W4 '12 n=227; W5 '12: n=209)

Actions If Damaged Underground Natural Gas Line

- In the event of a damaged underground natural gas line on their property, BC residents remain most likely to contact FortisBC, their gas company, or an emergency response provider, either first or next (89%).
- Residents continue to be less likely to evacuate their house or property (58%).

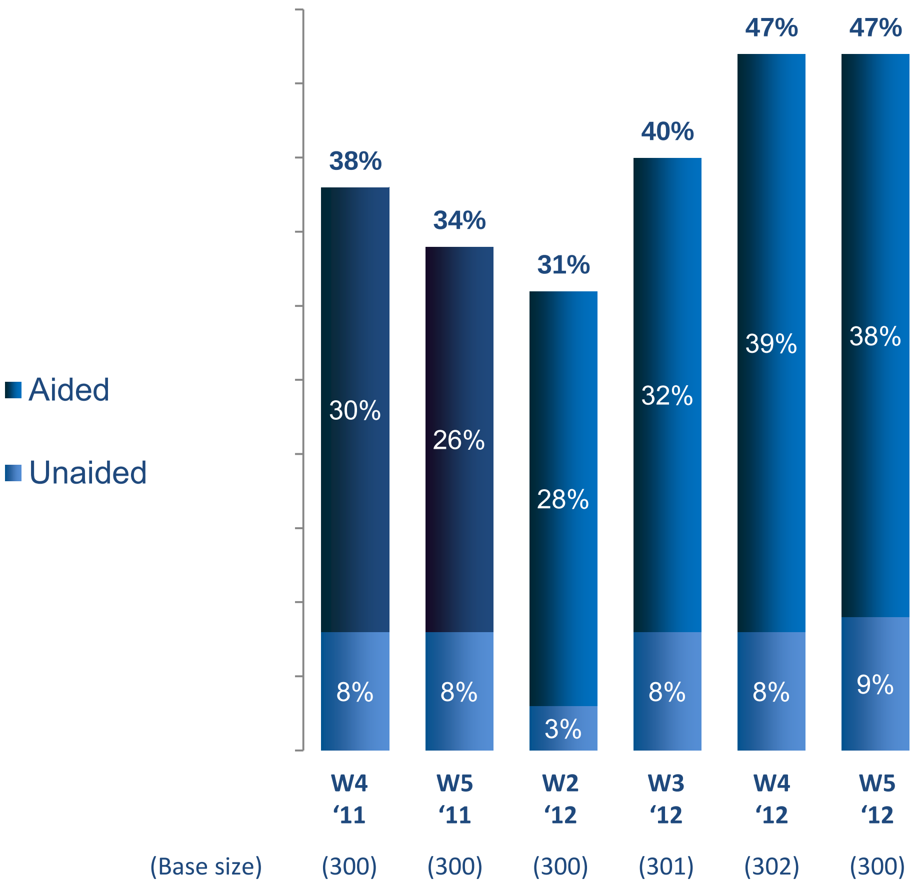


A20 If you damaged the underground natural gas line, what would you do first? And what would you do next?

Base: All respondents (W4 '11: n=300; W5 '11: n=300; W2 '12: n=300; W3 '12: n=301; W4 '12: n=302; W5 '12: n=300)

Awareness Of BC One Call

- Following steady increases since Wave 2, 2012, overall awareness of BC One Call has stabilized at just under half of all residents (47%). Unaided awareness has remained fairly constant at just under one-in-ten residents (9%).
- Awareness of BC One Call continues to be higher in the Lower Mainland and among males relative to residents elsewhere and females.



A22 Have you ever heard of BC ONE CALL?

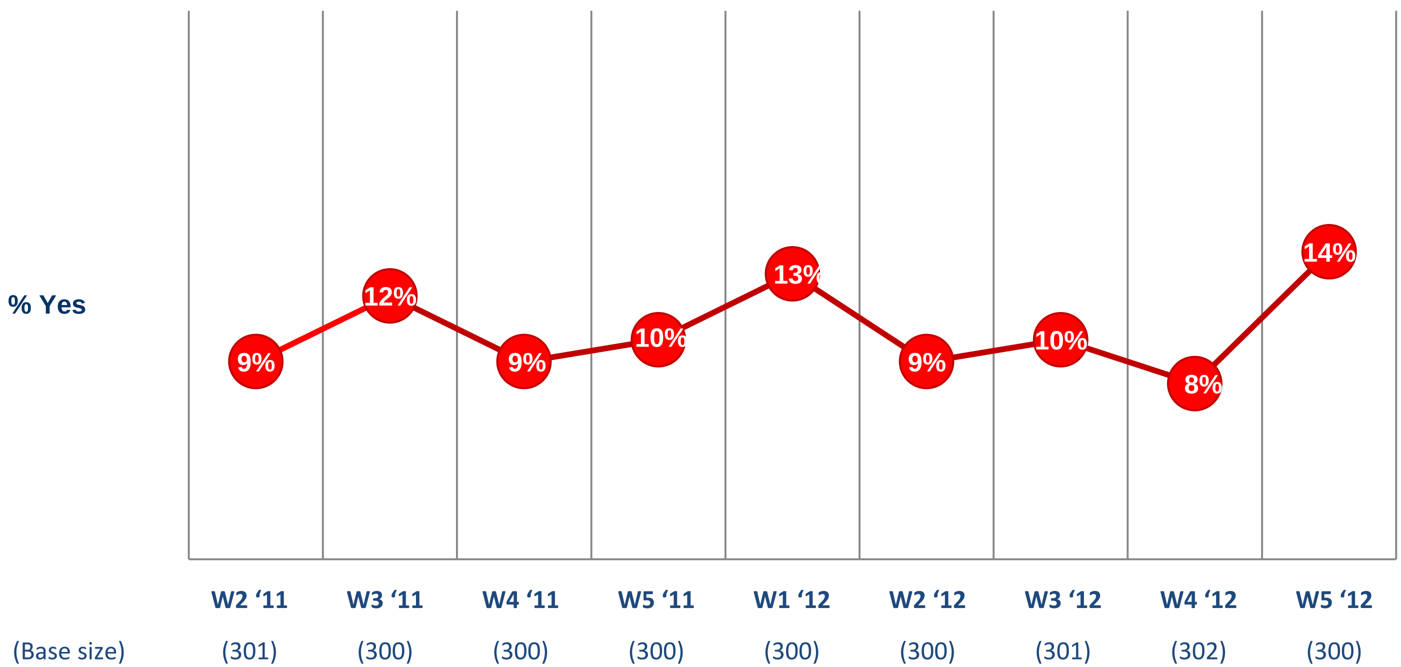
Base: All respondents

Natural Gas Safety Behaviour

Instructions For Natural Gas Leak/Emergency

- Slightly more residents claim to have posted a plan of what to do in the event of a natural gas leak or an emergency in their home than last wave (14% vs. 8%, respectively). However, the current reported incidence is not significantly above historical levels.

Have a Gas Leak/Emergency Plan Posted in the Home

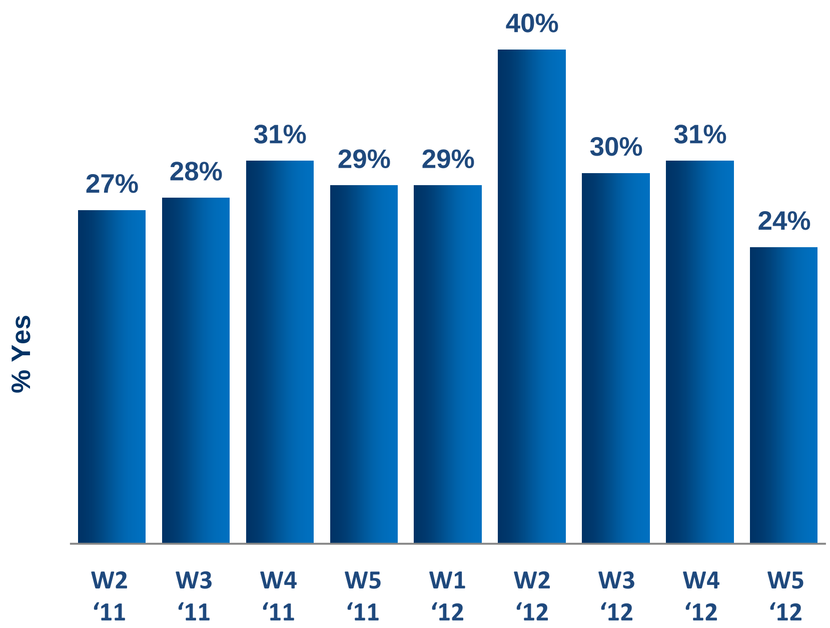


A16 Do you have a plan that is posted somewhere in your home with instructions on what to do in the event of a natural gas leak or an emergency?
Base: All respondents

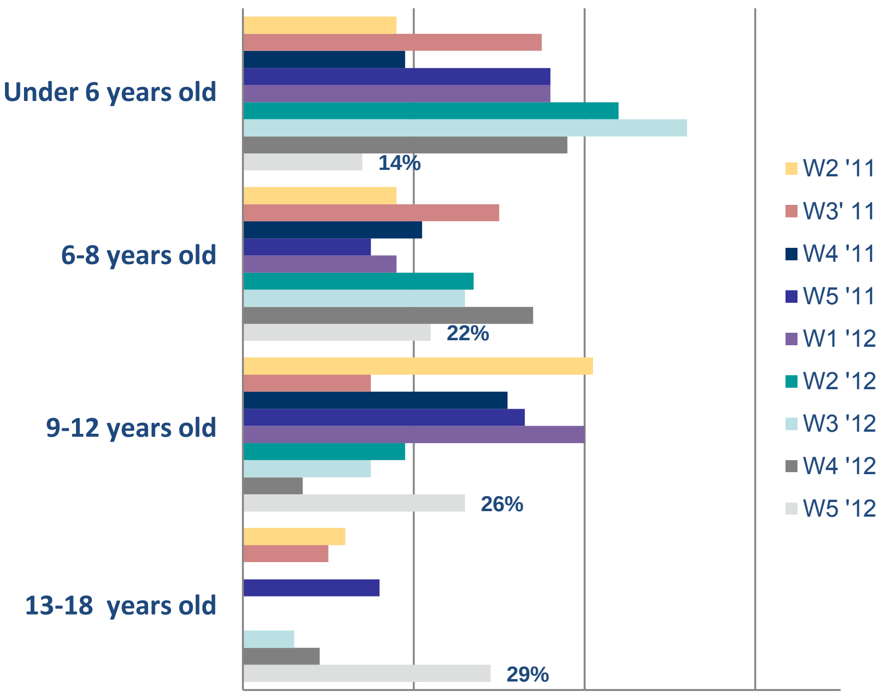
Discussion Of Natural Gas Safety With Children

- The incidence of discussing natural gas safety with children in the household has not changed significantly. About one-quarter of residents with children aged 6 to 18 in the household say they discuss safety with their children of all age groups.

Discuss Natural Gas Safety with Children



Age of Children



D6b Have you at any time discussed natural gas safety with them?

Base: Those who have children

D6c At what age were they when you first discussed natural gas safety with them?

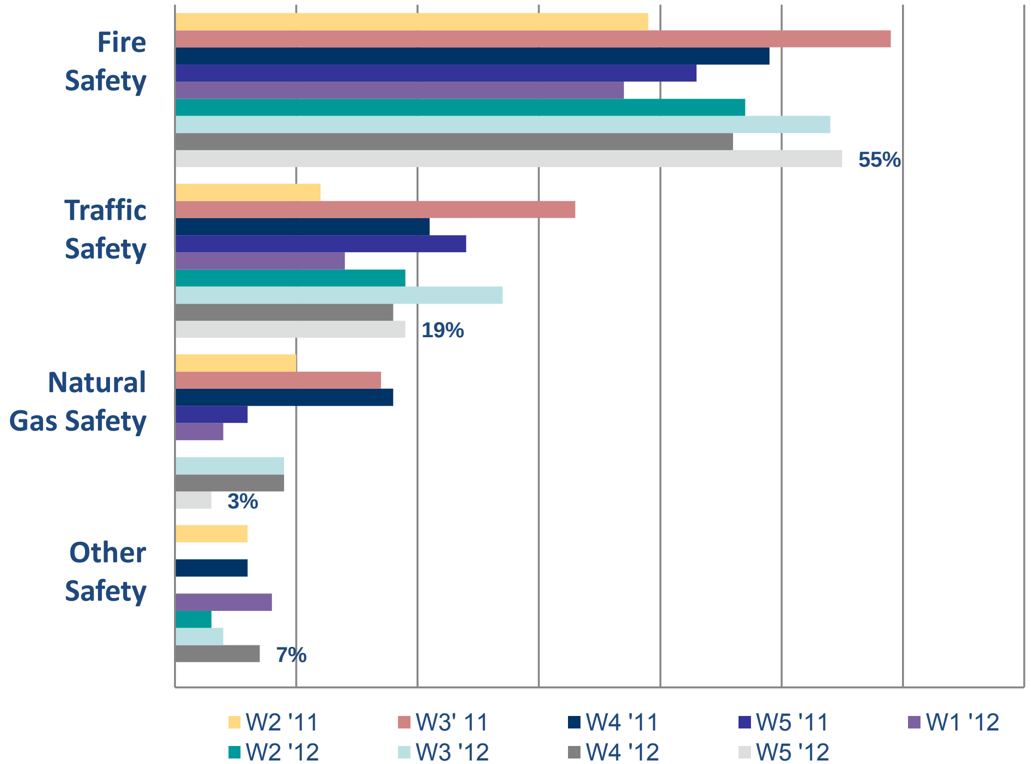
Base: Those who discussed natural gas safety with children (W2 '11: n=21*; W3 '11: n=18*; W4 '11: n=22*; W5 '11: n=21*; W1 '12: n=22*; W2 '12: n=25*; W3 '12: n=23*; W4 '12: n=25*; W5 '12: n=22*)

*Caution: Small base size

Safety-Related Information

- Just over half (58%) of BC residents with children aged 6 to 18 in the household recall their children bringing home safety-related information in the past year. As in previous waves, the type of information most likely to be brought home is fire or traffic safety rather than natural gas safety.

Topic of Safety Information



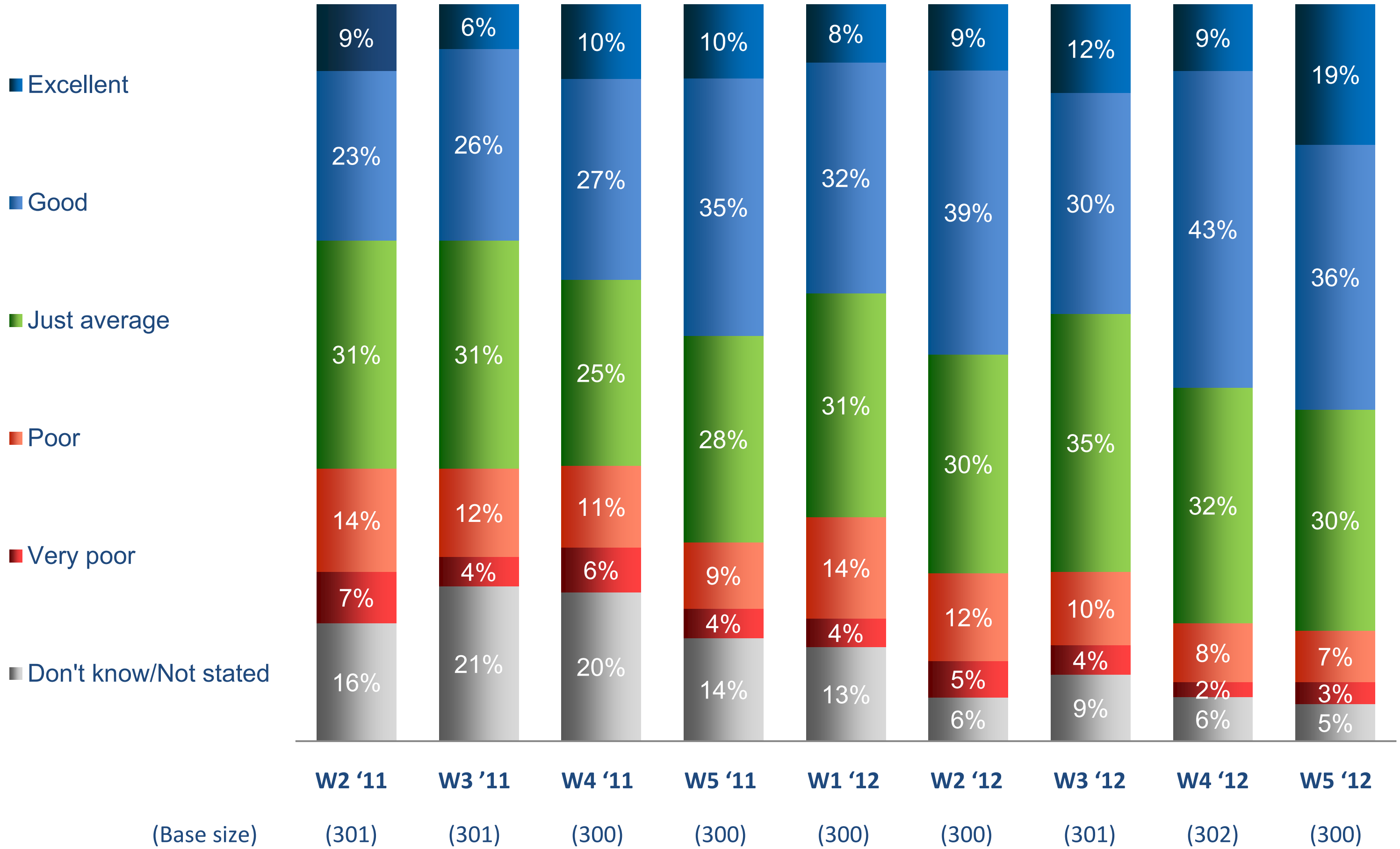
Total adds up to more than 100% as respondents could provide *more* than one answer.

C6 In the past year, have your children brought home any safety-related information on such topics as fire safety, traffic safety or natural gas safety?

Base: Those who have children aged 6-18: (W2 ‘11: n=70; W3 ‘11: n=56; W4 ‘11: n=72; W5 ‘11: n=52; W1 ‘12: n=64; W2 ‘12: n=56; W3 ‘12: n=66; W4 ’12: n=61; W5 ‘12: n=72)

Rating Of Public Safety Information On Natural Gas

- Just over half (55%) of residents rate their natural gas company positively for informing the public about natural gas safety, consistent with the last wave. However, about one-in-five (19%) now believe their gas company is doing an "excellent" job of informing the public, significantly higher than in all previous waves.
- One-in-three continue to rate their gas company's performance as "just average", while one-in-ten consider it to be poor.



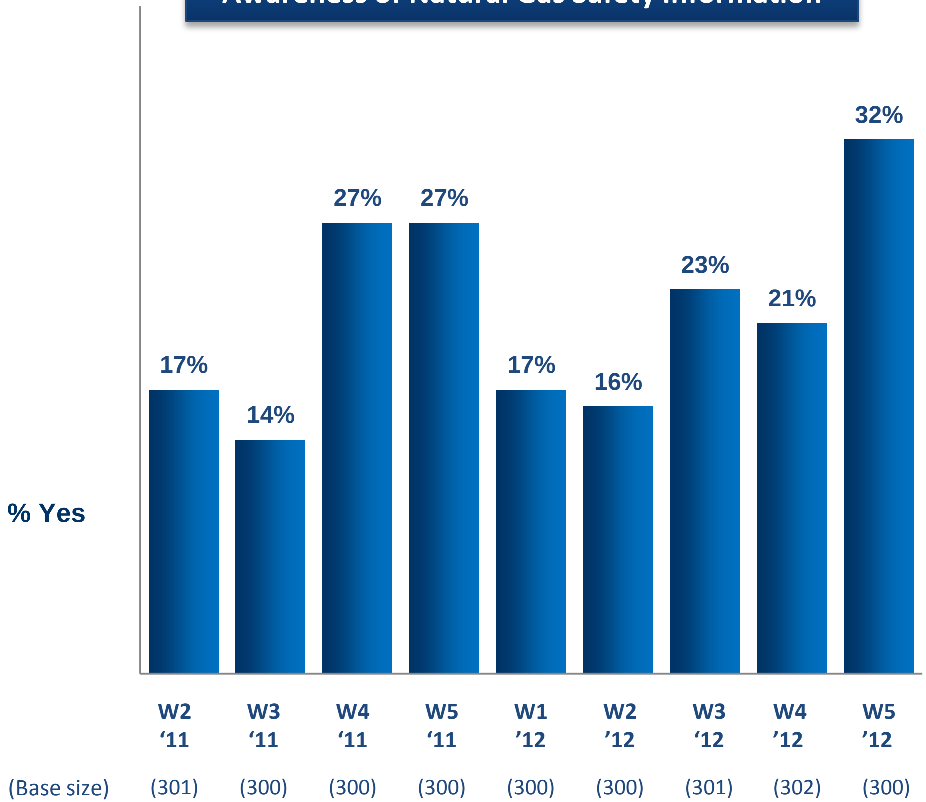
C7 Overall, how would you rate your local natural gas company on informing the public about how to be safe around natural gas?
Base: All respondents

Advertising Awareness

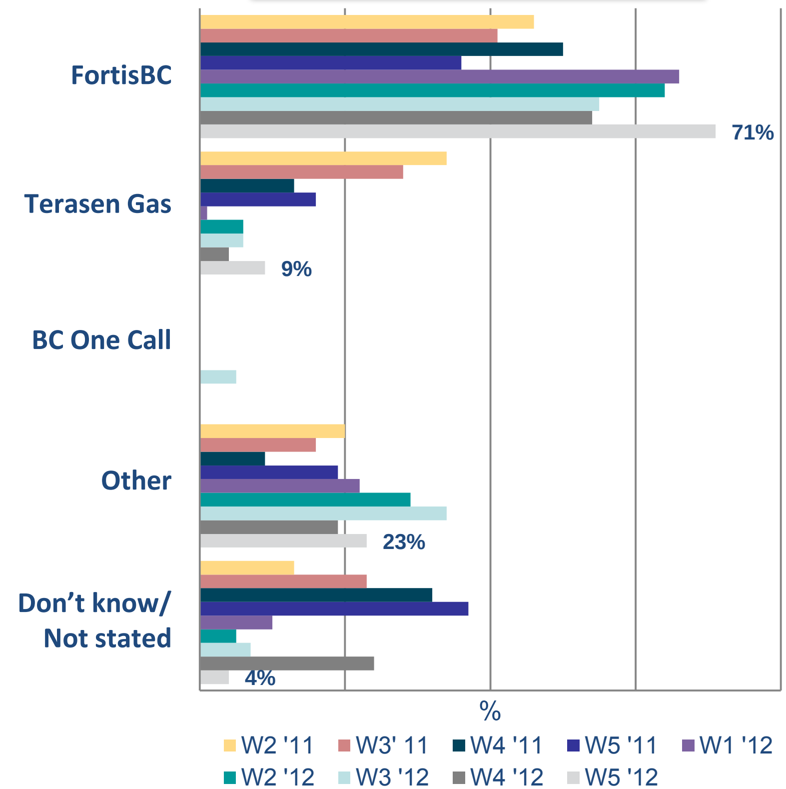
Awareness Of Natural Gas Safety Advertising

- Awareness of receiving natural gas safety information in the past 6 months has increased significantly to almost one-third (32%) of BC residents from just one-fifth (21%) in the last wave.
- Residents who do recall such information are also much more likely to attribute its source to FortisBC/Terasen Gas (71% vs. 58% in Wave 4, 2012). Fewer residents were unsure of the source compared to last wave (4% vs. 24%, respectively).

Awareness of Natural Gas Safety Information



Source of Information



B1 In the past 6 months, do you recall seeing, hearing or receiving any information about natural gas safety?

Base: All respondents

B2 Which organization was this information from?

Base: Those aware of advertising (W2 '11: n=48*; W3 '11: n=40*; W4 '11: n=73; W5 '11: n=81; W1 '12: n=47*; W2 '12: n=46*; W3 '12: n=67; W4 '12: n=62; W5 '12: n=92)

*Caution: Small base size

Main Message Of Advertising

- The main message most commonly associated with recent safety communications continues to be related to the appropriate action to take in you smell a natural gas leak (19%).
- Other main messages recalled by residents include who to contact in case of an emergency (17%), general safety issues (16%), or how to identify a gas leak or react to one (15% each).

	W2 '11	W3 '11	W4 '11	W5 '11	W1 '12	W2 '12	W3 '12	W4 '12	W5 '12
Base (Those aware of advertising)	48* %	40* %	73 %	81 %	47* %	46* %	67 %	62 %	92 %
If you smell gas, get out/get help	23	9	25	22	29	21	11	18	19
Who to contact in case of an emergency	23	10	14	5	17	16	5	2	17
Safety issues (gen)	9	12	14	10	22	16	12	10	16
How to identify a gas leak	18	22	10	21	9	6	9	5	15
What to do if you detect a leak (gen)	9	20	8	11	23	12	11	15	15
What the smell is	-	-	-	-	8	14	17	21	11
Regarding pipeline location/know where lines are before digging	-	-	-	-	-	-	-	-	7
Call before you dig	8	6	28	40	7	13	10	7	4
Other	7	22	9	7	26	14	25	32	21
Don't know/Not stated	9	5	7	7	6	14	21	17	13

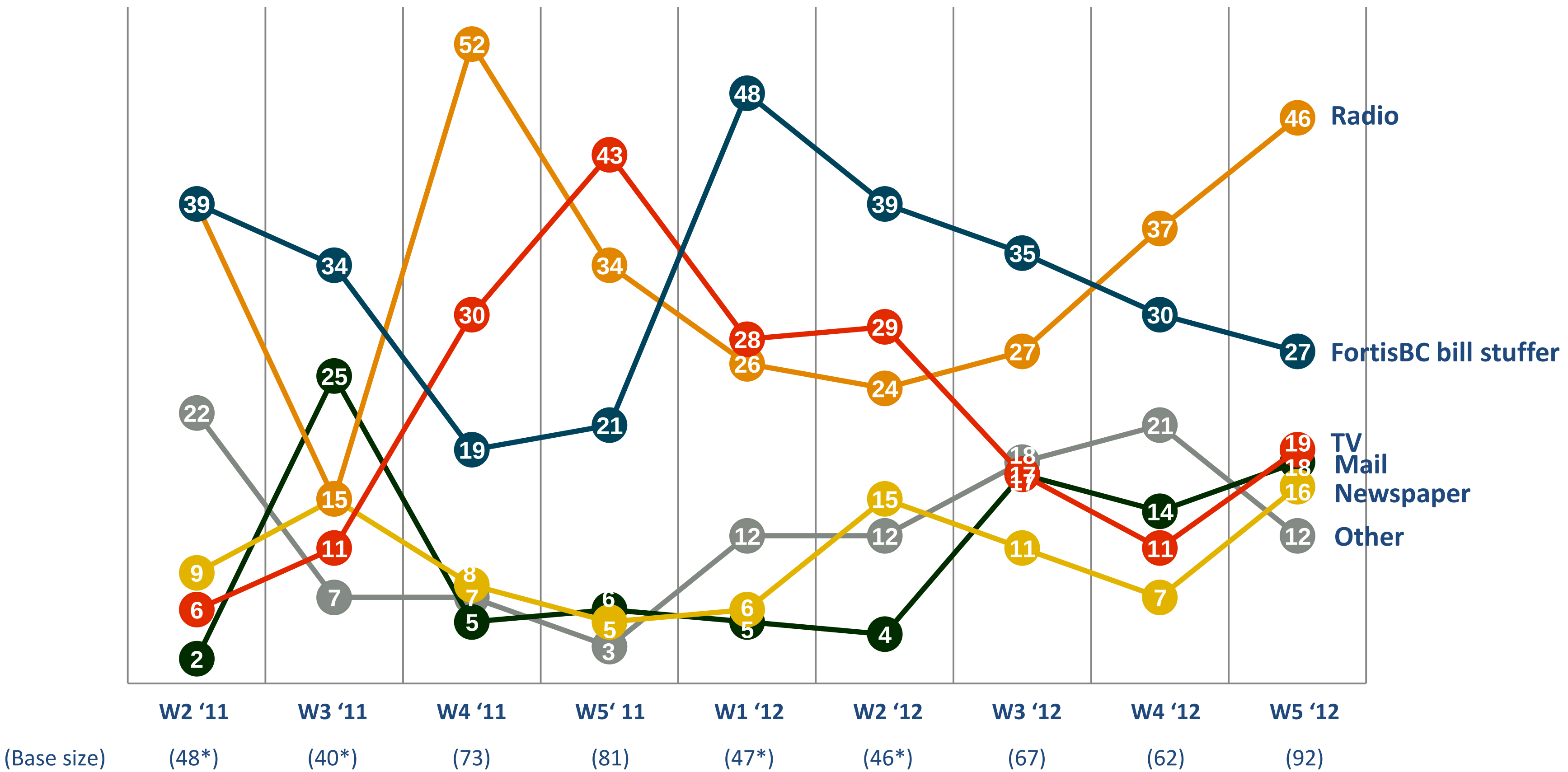
B3 What was the main message of the information?

Base: Those aware of advertising

*Caution: Small base size

Sources Of Awareness

- Among residents aware of recent natural gas safety advertising, mention of radio as the source of awareness continues to rise in tandem with exposure to the fall radio campaign (to 46% from only 24% in Wave 2, 2012). There has been a corresponding decline in mentions of FortisBC bill inserts over the last five waves (to 27% from 48% in Wave 1, 2012).



Total adds up to more than 100% as respondents could provide more than one answer.

B4 Where did you hear, see or read this information?

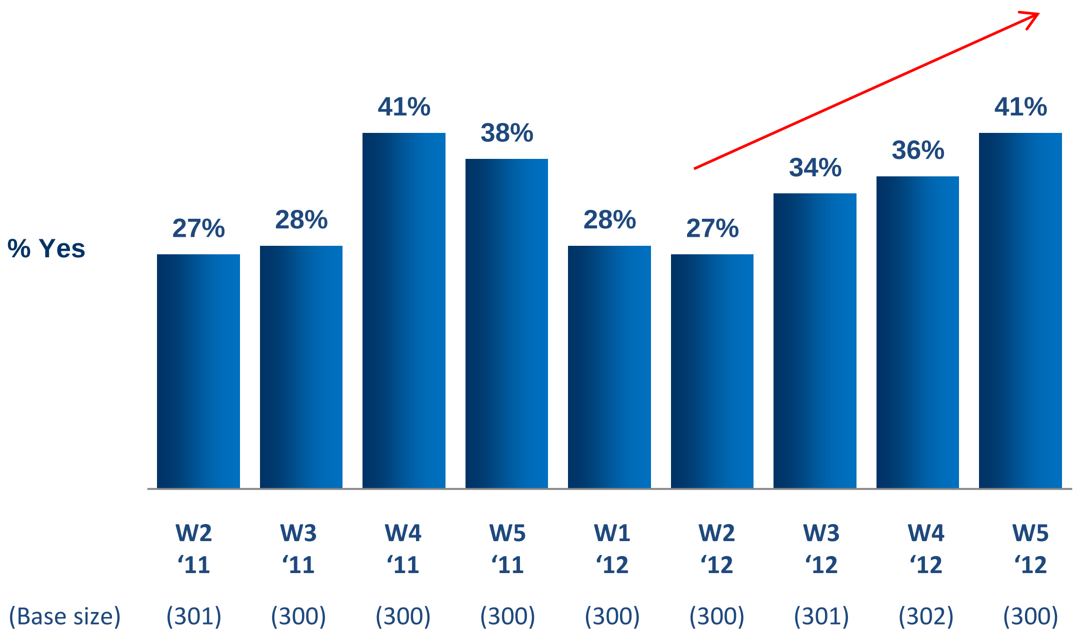
Base: Those aware of advertising

*Caution: Small base size

Awareness Of Terasen Gas/FortisBC Advertising

- The trend towards increasing awareness of FortisBC advertising continues. Currently, four-in-ten residents recalls hearing, seeing or reading any ads from the company in the past six months, compared to less than three-in-ten who did so in Wave 2, 2012, prior to the launch of Fall radio campaign (41% vs. 27%, respectively).
- In contrast to previous waves, home owners are no more likely than renters to recall such advertising. However, awareness tends to be higher among males and higher income, better educated residents than it is among females and those with lower incomes or education.

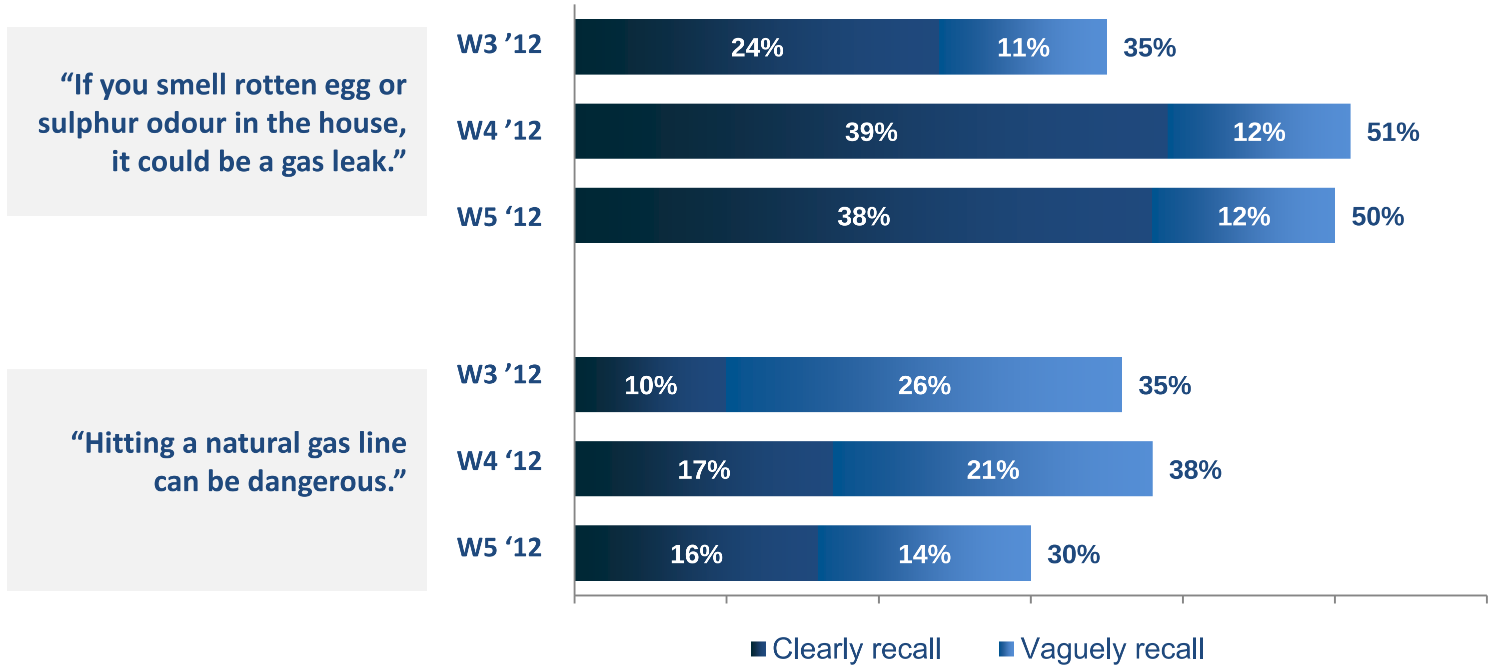
Awareness of FortisBC Advertising



B5 In the past 6 months, do you recall hearing, seeing or reading any ads from Terasen Gas/FortisBC?
Base: All respondents

Awareness of Radio Ads

- Half of all residents say they recall the ad promoting appropriate behaviour in the event of a natural gas leak in the home, unchanged following a sharp increase last wave. As in Wave 4, recall of this ad is much more likely to be "clear" (38%) rather than "vague" (12%).
- Recall of the ad related to "Call before you dig" has declined (30% vs. 38% in Wave 4), although the proportion of residents who remember the ad clearly has not changed significantly (16% vs. 17% in Wave 4).
- Recall of the ad related to natural gas leaks is lower in the Interior than in other regions, and males continue to claim higher recall of this ad compared to females.



B6 [One/another] radio ad features a man barbequing, telling his son that, "If you smell rotten egg or sulphur odour in the house, it could be a gas leak. Make sure you get everyone outside first then call nine-one-one or Fortis BC."

B7 [One/another] radio ad features a man receiving a quote for a new fence with the following message. "Hitting a natural gas line can be dangerous. Whether you're planting trees, building a deck, or putting in a fence – stay safe, call BC-One Call before you dig."
Do you clearly recall, vaguely recall, or do not recall this advertisement from FortisBC?

Base: All respondents (W2 '12: n=300; W3 '12: n=301; W4 '12: n=302; W5 '12: n=300)

Respondent Profile

Natural Gas Usage & Supplier

	W2 '11	W3 '11	W4 '11	W5 '11	W1 '12	W2 '12	W3 '12	W4 '12	W5 '12
Base (All respondents)	301 %	300 %	300 %	300 %	300 %	300 %	301 %	302 %	300 %
Natural gas service									
Yes, currently	65	74	68	68	70	71	74	71	71
Yes, previously	15	12	12	18	15	12	9	27	27
Base (Those with natural gas service)	176 %	197 %	178 %	181 %	182 %	187 %	195 %	194 %	188 %
Receive monthly natural gas bill									
Yes	84	84	84	86	86	85	86	87	92
Natural gas supplier									
FortisBC	56	57	62	61	75	68	71	67	68
Terasen Gas	18	18	12	13	9	8	12	13	12
BC Hydro	4	3	2	3	2	9	3	2	2
Pacific Northern Gas	5	4	3	4	1	2	1	3	2
BC Gas	4	3	-	1	3	1	-	1	2
Other	1	1	-	1	1	1	1	1	1
Don't know/Refused	12	13	21	16	11	11	11	14	13

Respondent Profile

	W2 '11	W3 '11	W4 '11	W5 '11	W1 '12	W2 '12	W3 '12	W4 '12	W5 '12
Base (All respondents)	301 %	300 %	300 %	300 %	300 %	300 %	301 %	302 %	300 %
Gender									
Male	39	47	45	46	48	42	43	49	47
Female	61	53	55	54	52	58	57	51	53
Age									
18-34	12	7	9	11	7	12	10	15	11
35-54	36	35	36	29	37	30	36	36	37
55+	51	57	55	58	55	57	53	50	52
Education									
High school or less	28	18	31	33	28	24	26	27	23
Coll/Voc/Tech; Some Univ.	41	39	31	36	41	44	44	42	44
University grad. or above	29	38	35	28	29	32	30	31	31
Household Income									
Less than $55,000	33	21	31	30	33	34	23	32	28
$55,000 to < $100,000	29	25	24	27	25	24	33	27	28
$100,000 or more	16	19	18	16	23	22	21	22	21
Refused	22	34	27	27	19	20	23	20	23

Respondent Profile

	W2 '11	W3 '11	W4 '11	W5 '11	W1 '12	W2 '12	W3 '12	W4 '12	W5 '12
Base (All respondents)	301 %	300 %	300 %	300 %	300 %	300 %	301 %	302 %	300 %
Region									
Metro Van/Fraser Valley	62	62	62	62	62	62	62	63	63
Interior	27	27	27	27	27	27	27	27	27
Vancouver Island	10	10	10	10	10	10	10	10	10
Type of dwelling									
Single detached	62	66	63	63	69	67	70	69	71
Duplex/Townhouse/Row	15	11	12	14	12	11	11	12	14
Condominium/Apartment	17	14	19	16	15	19	15	15	12
Other	6	5	5	7	3	4	3	4	3
Home ownership									
Own	76	83	83	76	81	83	81	85	80
Rent	23	14	16	21	16	17	17	13	19
Primary language spoken									
English	94	92	93	93	94	94	95	95	94
Non-English	6	6	6	6	3	6	5	5	6

Appendix

Safety Preparedness Index

Safety Preparedness Segments

Survey respondents segmented into four groups, depending on their level of "preparedness" for a natural gas leak. The four segments are defined as follows:

Extremely Prepared

- Included in this group are respondents who correctly answer either all four questions or all questions for which they qualify to answer. Historically, fewer than five percent of respondents qualify for this group.

Very Prepared

- Respondents who correctly answer the following questions fall into this segment. This group typically represents between one-fifth and one-quarter of respondents.
    - Know the gas smell [QA9a] or Recognize a gas leak [QA10] (i.e. rotten eggs or sulphur)
    - Know what to do first (get out of the house) [QA11]
    - Know who to call (911/Gas company/FortisBC/Terasen Gas) [QA12]

Somewhat Prepared

- Respondents who correctly answer the following questions qualify for this segment. This group typically represents between less than of respondents.
    - Know the gas smell [QA9a] or Recognize a gas leak [QA10] (i.e. rotten eggs or sulphur)
    - Know who to call (911/Gas company/FortisBC/Terasen Gas) [QA11 or QA12]

Not at All Prepared

- All remaining respondents are included in this segment, which generally comprises the majority of total respondents.

Safety Preparedness Index

	2012	2013				
	YTD	Wave 1	Wave 2	Wave 3	Wave 4	Wave 5
Base (All respondents)	**1503** **%**	300 %	300 %	301 %		
Preparedness Indicators						
1. Know the gas smell (rotten eggs or sulphur) [A9a & A10]	**60**	65	62	70		
2. Know what to do first (get out of the house) [A11]	**46**	47	37	48		
3. Know who to call (911/gas company/FortisBC/Terasen Gas) [A12] Top row: 2nd mentions only/*Bottom row: 1st & 2nd mentions*	**56** ***75***	55 *74*	48 *68*	58 *75*		
4. Have gas emergency plan posted [A16]	**11**	12	9	11		
Preparedness Groups						
Extremely Prepared	**2**	4	1	3		
Very Prepared	**23**	24	18	30		
Somewhat Prepared	**21**	20	21	22		
Not At All Prepared	**54**	52	60	45		

= Significantly lower than in previous wave (green box)

= Significantly higher than in previous wave (red box)

Safe Excavation Index

Safe Excavation Segments

Survey respondents are segmented into four groups, depending on their level of "preparedness" for a safe excavation. The four segments are defined as follows:

Extremely Prepared

- Know information about where underground utilities are located is available [QA18] + know you have to contact someone before digging [QA20a] + know who should be contacted (either FortisBC or BC One Call) [QA20b] + aware of BC ONE CALL [QA19/QA20b/QA20/QA21/QA22].

Very Prepared

- Know information about where underground utilities are located is available + know you have to contact someone before digging + DON'T know who to contact or answer incorrectly + aware of BC ONE CALL.

Somewhat Prepared

- Know information about where underground utilities are located is available + know you have to contact someone before digging + DON'T know who to contact or answer incorrectly + NOT aware of BC ONE CALL.

Not at All Prepared

- None of the above

Safe Excavation Index

	2012	2013				
	YTD	Wave 1	Wave 2	Wave 3	Wave 4	Wave 5
Base (All respondents)	**1203** **%**	300 %	300 %	301 %		
Preparedness Groups						
Extremely Prepared	**15**	20	13	18		
Very Prepared	**9**	9	9	11		
Somewhat Prepared	**15**	14	14	15		
Not At All Prepared	**61**	58	63	57		

= Significantly lower than in previous wave

FortisBC:
BC One Call and Safe Excavation Focus Groups

Report on Findings

March 13, 2013

Table of Contents

Executive Summary and Recommendations

Executive Summary

The following summarizes the results of 3 focus groups held with ground disturbance contractors operating in the Lower Mainland of BC regarding the services of BC One Call (BC1). The primary discussion topics were their excavation practices as it relates to BC1 and ways and means of effectively communicating with them. The groups took place on February 13 and 14, 2013. Respondents were recruited from contacts provided by FortisBC and given a $175 honorarium to encourage participation. The discussion followed a guide developed in conjunction with FortisBC.

1. Focus group respondents for this project represented a wide range of construction and excavation companies; municipalities, landscapers and a pipeline company. It was clear that the larger organizations had firmly entrenched BC1 in their excavation and planning processes. Smaller firms were aware and frequent users of BC1; however, they sometimes failed to request a BC1 ticket prior to ground disturbance.
2. Respondents demonstrated a high knowledge level of BC1 processes, its supporting organizations such as FortisBC, and the consequences of not calling prior to digging. Respondents expressed disappointment that not all utilities and municipalities are members of the BC1 service.
3. It was clear that the larger organizations have entrenched processes and protocols designed to ensure that was undertaken in a safe manner. This was not always achieved. Meanwhile, smaller firms were adamant that they always contact BC1 prior to starting work but would contradict themselves later in the discussion citing examples where calling was not part of the process.
4. Reasons for not calling prior to digging are:
    - Lack of awareness (particularly on the part of homeowners) of BC1 services
    - Misjudging the scope of the work. Respondents said that there is likely a perception that calling BC1 is only required for large projects that involve digging equipment rather than something as simple as landscaping a garden.
    - Lack of time and budget. Participants said that they are sometimes confronted with a choice between losing a subcontracting job and calling BC1. Despite their awareness of the emergency BC1 service

they would rather assume that the general contractor had made the call and take the risk than potentially lose the income.

- Lack of permits. Participants said that some jobs are done without proper permitting and speculated that such contractors would be reluctant to call for fear of being discovered.
- Contractors will sometimes assume that the dig site is unserviced and therefore do not call BC1.
- Contractors speculated that homeowners will often assume that BC1 charges for its services and therefore do not call for fear of generating higher costs for their projects.

5. The factors that respondents noted as causing underground service hits are:
   - Receiving incorrect or difficult to interpret maps from the utilities and underground facility owners
   - Older as-built drawings which do not accurately record the placement of the service line or where reference points have been changed over time.
   - Unavailability of information about water and sewer lines on private property.
   - Ground changes that occur over time such as topsoil removal that decreases depth and tree root entanglements around service pipes and cables.
   - Participant companies (not FortisBC) failing to respond to BC1 requests in a timely manner
6. Contractors were able to list many consequences of service line hits. They included financial penalties, personal injury or death, insurance premium increases, environmental damage, WorkSafe fines, significant local service outages, personal embarrassment, loss of reputation and other legal ramifications such as covering the cost of damages.
7. Awareness of BC1 comes from a variety of sources including on-the-job training, advertising (usually radio and print), FortisBC and other member utilities; WorkSafe communications, trade organizations, stickers and some municipal permitting offices.
8. When asked which languages should be used for in-language communications, respondents recommended that Punjabi, particularly within the Fraser Valley is most important to address followed (by some distance) by Chinese dialects.
9. Respondents spend a great deal of time on the road and therefore their media habits revolve around AM radio bands that provide traffic information. Community newspapers receive some level of attention as do the sports sections of mainstream news outlets.

Recommendations

1. **Consider pooling communications resources under the BC1 brand rather than the individual member utilities.**

   When it comes to mitigating ground disturbance strikes on utility lines, it was abundantly clear that BC 1 Call holds the strongest brand identity over that of its member utilities and despite the fact that it is the utilities that ultimately respond to the call. As such, most dial-before-you-dig messages are attributed to BC1. Pooling communication funds among its member utilities could ultimately lead to stronger and diversified messaging activities.

2. **Review the specific tactical recommendations beginning on page 18 of this report.**

3. **Conduct additional research with do-it-yourself homeowners to learn more about their attitudes and understanding of the BC1 message.**

   Respondents could only speculate on what homeowners know and understand about BC1. While it makes intuitive sense that this population doesn't perceive a need to call BC1 before starting a home project, the actual extent and their perceptions remain unknown.

4. **Conduct additional research with small contractors to learn about their specific difficulties in using BC1 services and to understand the extent of problems that cause them to not call BC1 before excavating.**

   It should come as no surprise that smaller contractors are less likely to call BC1 before starting a project. Their projects are smaller and experience greater cost and time pressures. Participants in these focus groups did not necessarily confess to this for fear of being judged by other participants. To learn the full extent of this problem, further investigation may be required.

Background and Objectives

Background

In conjunction with BC Hydro, TELUS and other organizations, FortisBC supports the *BC One Call* (BC1) service that provides an underground utility information service designed to mitigate service disruptions from construction excavation work. Besides the telephone and online service, they also sponsor awareness campaigns that use radio ads, Web site content and printed materials that encourage contractors to "Call before you dig."

BC1 messaging focusses on three key steps that work to reduce disturbance in services: calling BC1 for proper information, marking the location of gas lines and following proper digging protocols.

Objectives

This study:

- Assessed the level of safe excavation knowledge among contractors;
- Developed an understanding of why hits occur;
- Identified FortisBC's role in providing information;
- Recommended appropriate communication channels and activities as well as evaluate current materials for effectiveness;
- Determined the extent that language forms a barrier to current services.

Methodology

Focus Groups

Focus groups were used to address the research objectives because they allow respondents to expand on their answers and work with each other to develop comprehensive answers to open-ended questions.

Methodology Details

Participant Research conducted 3 focus groups in the Lower Mainland of BC targeting those that engage in excavation activities. These groups include heavy equipment operators; general contractors; landscaping and construction company employees and municipal employees.

Group	Time	Organization Type	Location
1	7:00AM	Large (including municipalities)	Surrey
2	5:30PM	Small and Large Firms	Surrey
3	7:00AM	Small and Large Firms	Vancouver

The Vancouver focus groups took place in standard focus group facility equipped with a one-way mirror to facilitate observation. In Surrey, hotel meeting rooms were used and connected by closed circuit television monitors. The discussion will follow a guide developed in conjunction with representatives from FortisBC.

Research Limitations

In General

The normal limitations of qualitative research must be kept in mind. Respondents were selected non-randomly and as such, their views cannot be regarded as quantifiable or projectable to any specific population cohort.

The information obtained may be viewed as an indication of existing attitudes but not the extent to which such attitudes are represented in any defined population.

Finally, in-depth interviews are not "unreliable surveys." Rather, they are idea-generating vehicles where any avenue of information that appears to evoke useful ideas or problem solving suggestions is pursued and reported.

The results from this research should be considered as directional.

Key Findings

The following sections address these findings:

1. Perspective on Respondents
2. Ground Disturbance Processes
3. Not Calling, Hits, and The Consequences
4. Information Sources
5. Marketing Communications

Perspective on Respondents

Business Size of Excavators

Focus groups respondents represented a variety of business sizes. Although larger firms were somewhat over-represented we were also able to hear from smaller firms. Clearly, when it comes to using BC1 services, larger firms had such contact firmly built into their operating procedures.

As a result, calls to BC1 are made prior to any kind of ground disturbance activity because doing so is set out in policies and standard procedure checklists.

Although smaller contractors said that they *always* contact the service prior to an excavation, they would later say that they sometimes bypassed BC1 in favour of visiting municipal offices. At the same time, larger firms also made use of these services but BC1 was always included in the mix of resources to contact.

Knowledge of BC One Call

Regardless of contractor size, respondents were very aware of the BC One Call services. Respondents easily recalled overall contact procedures, which utilities and companies support the service and familiarity with BC1 maps and drawings.

They easily outlined the process of how to initiate contact with BC1, the time lines to expect, and the varying repercussions of not calling (i.e. WorkSafe and legal complications).

Respondents were disappointed that not all organizations – particularly some municipalities – are part of the service.

Share Principles

Respondents were asked directly if the issues that revolve around ground disturbance activities are the same for all contractors and homeowners or if they differ in some way.

They replied that while project complexity usually increases with business size, the fundamental issues of legal liability and the potential extent of damage is the same for everyone – contractors and homeowners alike.

Ground Disturbance Processes

Respondents were asked to describe the process leading up to excavation. With little variation, they said that the planning for a job can range from overnight to six months depending on project complexity.

For larger projects, many factors are taken into account such as securing needed permits, scoping out the kinds and types of equipment that will be required and mapping out the project site.

Smaller projects receive much less attention. It was clear that little up front work is done for these projects other than perhaps physically marking where the digging should take place and contacting BC1.

Protocols

Larger firms said that they all maintain a check list of steps leading up to an excavation. Invariably they all reported that contacting BC1 is a consistent part of these check lists.

We observed that respondents said that they always contact BC1 on every job but subsequent discussion revealed that this is not always the case. In fact, for small contractors, the lead-up to the job can never take place fast enough. This leaves substantial room for error.

Not Calling, Hits, and the Consequences

Reasons for Not Calling BC1

One of the biggest reasons for striking underground services was not making a call to BC1. Respondents provided multiple reasons for not calling and most of them related to an overall lack of awareness and not wanting lose the work.

Lack of Awareness and Misjudging Project Scope
Contractors agreed that "do-it-yourselfers," in particular, are unaware of the need to call BC1. They said that homeowners often consider their projects as cosmetic and straightforward and therefore unaware that services can lie shallowly in their yards. While they are aware of the BC1 service they consider calling as something for larger, commercial projects; not for something as small as installing a fence.

One contractor spoke of installing a post for a mailbox and striking an underground cable when he was simply trying to break up the soil with a tamping rod. He said the job just didn't seem like one that would require a call to BC1 because the hole he was manually digging was only inches deep. Respondents added that this was a very common misperception among homeowners.

> *"I wasn't using a machine to dig, so I don't need to call."*
>
> *- Vancouver*

Time and Budget
Contractors can receive short-order work requests from clients. In these instances they are asked to come to the worksite the same or the following day. In these cases, the excavator who calls BC1 could lose the job because of potential delays caused by locating underground services. In some instances, rental equipment is brought in by sub-trades and such services only rack up expense as underground services are identified.

> *"For big companies, it's expected* [that they will call] *but the smaller guys don't have that luxury. They have to take the risk or they will lose the job."*
>
> *- Vancouver*

Interestingly, respondents made this comment despite common knowledge that BC1 offers emergency services.

Lack of Permits
Participants spoke of jobs where permits are not obtained prior to commencing work adding that some clients just don't want to pay for them. Were they to approach BC1 for information, their job could be easily identified as lacking a permit. Rather than lose the work or inflate its cost the excavator chooses to run the risk and dig anyway.

Underground Service Locations Are Available Elsewhere
One respondent believes that when he digs in Surrey, he can get the same, if not better, information from the municipal offices. He said that their maps were more comprehensive; including water and sewage services. He didn't see the need to contact BC1.

> *"It's really easy in Surrey. You don't have to call* [BC1] *because everything is all* [in their records]."
>
> *- Surrey*

Dispersion of Responsibility
Participants said another reason for not calling is an assumption that someone else, usually the general contractor, has already contacted BC1. In some of these cases, participants said that they did not want to be the one that is the cause of a work slowdown or stoppage.

> *"When we're subcontracted to someone, we rely on them to have done their homework. That is not always the case."*
>
> *- Vancouver*

Assumption That the Digging Site is Unserviced
Participants said that sometimes an open field can appear to have no services running beneath its surface. Inexperienced excavators will mistakenly assume that there is no need to call BC1.

Assumption that BC1 Charges for its Services
Respondents said that there is perception, mostly among homeowners, that the BC1 service costs money. They become reluctant to call because doing so might inflate the cost of their projects. There were no homeowners in these focus groups, so this observation must be considered as hearsay.

Causes of Hits

Participants had many reasons that explain why service line hits occur. These were:

Incorrect Information
Rightly or wrongly, contactors complained that the quality of the maps was often poor, difficult to interpret or out of date. As a result, these inaccuracies were said to be a significant source of miscalculations and strikes on cables and pipes. In addition, some charts were said to be inaccurate, depicting cables and pipes away from where they actually lie.

"Work Arounds"
In some instances, the actual underground installation varied from the as-built drawing. For example, a service line may have been jogged around an underground obstruction, but the drawing shows a straight running line.

Lack of Information
Municipal maps provided through BC1 do not provide sewage or water line information beyond the property line. The same holds true for FortisBC maps where the gas meter is located on a detached garage with an underground service running to the house. Any gas lines beyond the meter belong to the property owner and are not recorded on FortisBC maps. Participants are dependent on both the knowledge of the homeowner and professional location services to avoid damage to underground services. Larger scale excavations will often bring in hydro-vac services that locate underground services and use water and a vacuum to unearth them without causing any damage.

Changes Through Time
Sometimes, hits occur because other aspects of the property had changed. Over time, landscaping, re-grading, property line amendments and road re-alignments impact the reference points used to locate underground services. Respondents had multiple examples in which earlier excavating (e.g. installing a garden) had removed significant earth leaving the underground services nearer to the surface than the original installation.

In another example, one contractor said that tree roots had grown around pipes and when the root was pulled in one spot, it damaged pipes in another.

Companies Not Calling Back
Respondents said that some hits occur because BC1 member companies sometimes don't respond. For some, it is understandable because their services nearly always located next to another service. For example, Shaw Cable was said to almost always piggy-back on TELUS services. FortisBC was not considered as one of these companies.

Nevertheless, if the underground service owner doesn't return the request, participants said that they aren't worried about hitting the line because they did their due diligence.

> *"If they don't care about* [their lines] *then I don't care about them either."*
>
> *- Surrey*

Consequences of Hits

Respondents could easily identify many consequences of hits.

Personal Embarrassment
It's noteworthy that a significant emotional driver of avoiding hits is a sense of personal shame. Respondents noted that it is embarrassing to hit something and that doing so – regardless of other material consequences – is considered as a personal failure.

> *"I lost twenty pounds after* [a hit]. *I couldn't eat, I couldn't sleep. It was one of the worst times in my life."*
>
> *- Vancouver*

Other Consequences
Other, more material consequences were:

- Personal safety/death/disability
- Project delays (resulting in increased costs)
- Liability damage costs
- Insurance premium increases
- WorkSafe investigations and fines
- Significant local service outages
- Property and environmental damages/repair costs
- Poor reputation
- Legal ramifications

Of all of these consequences, respondents said that they most powerful "fear factor" was the potential for death or disability and the legal complications and expense that can result from a strike.

Information Sources

Participants were asked to review the varying information sources they have on the topic of ground disturbance activities.

Initial Awareness of BC1

Most respondents could not reliably recall how they first learned about BC1 services. For most, it had started very early in their working lives. For example, one respondent recalled that, as a swamper, he had asked his foreman about the flags placed around an excavation site. At that time he was told about BC1 and other locating services.

Despite their inability to remember, participants did say that throughout their working lives, reminders were always around encouraging them to call BC1. Such reminders were:

- Stickers such as bumper stickers or ones applied to equipment
- On-the-job training programs
- Utilities themselves (but respondents agreed that they don’t communicate enough)
- Municipal permitting offices
- Industry chatter – typically other contractors
- WorkSafe communications
- Trade organizations:
    - Christian Labour Association of Canada
    - Common Ground Alliance
    - Independent Contractors Business Association
- Radio, print, and limited television advertising

All of these sources were considered worthy for ongoing communications and information.

Less Recommended

There were some communication avenues that did not seem to resonate with respondents. These included:

- Social media including Facebook and Twitter. Specifically, they use Facebook to keep up with family and friends rather than business and there were no respondents that subscribed to Twitter.
- Telephone calls, email or newsletters

"I'm on the road or at the site. I don't want any calls and I don't read newsletters at all."

- Surrey

Media Consumption and Languages

Media Habits

All respondents reported that they spend a great deal of time in their vehicles driving to and from job sites. As a result, they said that they listen to an AM radio stations, especially traffic reports.

Other media included community newspapers, television news and the sports sections in mainstream newspapers.

Languages
When asked which languages other than English were prevalent in the digging community, respondents said that South Asian languages were most common followed by Chinese but to a much lesser extent.

As such, they recommended that in-language communications should primarily address South Asian dialects and use in-language radio stations such as DESI.

Marketing Communications

Respondents were asked a series of questions on how marketing communications could be enhanced and improved upon. Contractors came up with a wide range of suggestions, topics and recommendations. There were many of them – too many to add to the recommendations section of this report – so they are presented here as recommendations.

1. **Consider approaching BC1 communications in the same way that social change programs address societal problems.**

   Respondents spoke a great deal about mitigating risk and reducing harm. These themes are no different from programs that dissuade people from drinking and driving, smoking or encourage more healthy living. The common theme is changing behaviour to reduce risk to the person and others. There is abundant research into what makes these programs successful and unsuccessful and, if BC1 isn't already doing so, it may be helpful to review BC1 communications against a backdrop of social change campaigns.

> *"They (BC1) have a cartoon ad; but the drinking and driving folks would never do that."*
>
> *- Vancouver*

2. **Consider two communications programs: one for homeowners and one for contractors.**

   According to contractors, homeowners lack knowledge of how important it is to contact BC1 even when doing simple yard work such as installing a new fence or planting a tree. As discussed earlier in this report, respondents said that homeowners believe that the scope of their project is either too shallow or too small to warrant calling BC1. They recommended that while there is general awareness of dial-before-you-dig programs, homeowners do not consider themselves as a target for such communications.

   Potential venues for such communications could be at building supply outlets, municipal permitting offices, equipment rental firms (and on the equipment they rent), and weekend radio programs because that is when homeowners undertake most of their projects.

   Communications themes for homeowners could include the shallowness of some underground services; that even digging a small hole can lead to big problems; and that BC1 services are free and fast.

3. **Consider adjusting the tone of current advertising to one that is more serious.**

   Respondents said that the current humourous tone associated with some BC1 advertising approaches a serious topic too lightly. They said that such executions fail to communicate the serious consequences of striking underground services and as a result, are easily ignored.

4. **Consider using testimonials to communicate the need to call BC1.**

   A few respondents spoke about how impactful others' stories of the consequences of not calling *dial-before-you-dig* programs had been. One respondent recalled attending a training session when one man, injured and disabled from a pipeline strike, told of how important it is to call. Other respondents spoke of how anecdotes and experiences of colleagues had stuck with them and prompted them to call BC1 whenever they had a job.

   In a related comment, one respondent said that it would be interesting to see video that randomly asked people engaged in excavating if they had called BC1 and see how few actually do so and have them describe the reasons why they didn't.

5. **The key communications themes to use with contractors are minimizing property damage (expenses) and personal injury. A third theme that the service is free and very quick was considered important but more appropriate for homeowners.**

6. **Consider developing an online or electronic application that could provide job site training on BC1 services and safe excavation.**

   One respondent made this suggestion and the other respondents all voiced approval of the idea. Essentially, the course would be available on the internet or on a DVD. It could be presented at the job site for a whole crew to take in without significant disruption to the work schedule. He went on to recommend that a quiz should follow completion.

   Other contractors said that they hold "Tool Box" meetings at the job site at which people are brought in to speak about topics such as workplace safety or new policies or procedures. They said that BC1 would be a welcome participant at such meetings.

Appendix

- Recruitment Screener
- Discussion Guide

FortisBC – Focus Group Recruitment Script
Safe Excavation – BC One Call Service

Date:	**Interviewer:**	**ID#:**
Organization:		
Respondent Name:	**Title:**	
Address:		
City:	**Prov.: B.C.**	**Postal:**
Daytime Phone:	**Mobile (if possible):**	
E-Mail / Fax:		

Location	Date/Time
Vancouver Focus 1156 Hornby Street, Mezzanine Level Vancouver, BC Phone: (604) 682-4292	7:00AM
Sheraton Guildford Rooms TBA 15269 104 Ave Surrey, BC Phone:	7:00AM
	5:30PM

INTRODUCTION

Hello my name is ____________ _, with Participant Research an independent marketing research firm. We've been asked by BC One Call Service, or Dial-Before-You-Dig to conduct research on their services. May I please speak to (**NAME ON LIST**)?

We are very interested in speaking with you to learn your opinions about BC One Call Service. Therefore, we hope that you will participate in an informal discussion group held being held on (**INSERT DATE AND TIME**). FortisBC will use the research results to work with you more effectively.

The discussion will last about an hour and a half and is confidential. We are doing this on behalf of BC One Call so no one will attempt to sell you anything.

(RECONFIRM) Are you the person most likely to work with the BC One Call Service in your organization?

Yes **CONTINUE**
No **ASK TO SPEAK TO THAT PERSON AND RESTART RECRUITMENT SCREENER OTHERWISE THANK AND TERMINATE**

Is this something you would be interested in?

Yes **CONTINUE**
No **THANK AND TERMINATE**

CONTACT if needed:

Participant Research: Gerry Keane 604-339-8620 (Evening & Weekend calls OK)
FortisBC: Walter Wright 604-592-7653 (Business Hours only)

ALL MUST SPEAK CLEAR ENGLISH, NO OVERLY-HEAVY ACCENTS. ALL MUST BE ABLE AND WILLING TO ANSWER QUESTIONS CLEARLY AND EASILY. IF NOT THANK AND TERMINATE.

BACKGROUND

1. What is your occupation or job title?

---

2. Does any member of your household or immediate family work or have ever worked in the following? **[READ LIST]**

	Yes
A) Marketing or market research	☐
B) Advertising, communications or public relations	☐
C) Media (including newspapers, magazines, radio, TV, etc.)	☐
D) FortisBC, BC Hydro or any other energy provider	☐

IF "YES" TO A, B, C, D THANK & TERMINATE

INVITATION

As mentioned earlier, we are conducting discussion groups with people such as you about the BC One Call Service. This discussion is for research purposes only and we would like your insights and opinions.

I can assure you that no one will attempt to sell you products or services nor will be asking for any proprietary or confidential information. We'd just like to hear your honest opinions. The interview will be relaxed and informal.

FortisBC
Safe Excavation Focus Groups
Discussion Guide – FINAL
February 12, 2013

Objectives

- Assess the level of safe excavation knowledge among contractors;
- Develop an understanding of why hits occur;
- Identify FortisBC's role in providing information;
- Recommend appropriate communication channels and activities as well as evaluate current materials for effectiveness;
- Determine the extent that language forms a barrier to current services.

Discussion Guide

1. **Introduction (5 minutes)**
    a. Explanation of process, assurance of confidentiality; explanation of facility
    b. Discussion guidelines
    c. Answer any questions
2. **Warm-up (5 Minutes)**
    a. Describe for me how a typical excavation unfolds; step-by-step.
    b. *Moderator writes out process on a chart. If unmentioned ask*: At which point do you call BC One Call? *Probe for what kinds of tools they use to contact BC One Call (e.g. Internet, phone, others)*.
    c. And what does that process look like? If someone asked you for advice on what to watch out and/or do when they call BC One Call, what would you tell them? Is there anything you would tell them to avoid doing? Why?
        i. How is the quality of the information and maps that you receive in return from BC One Call?
3. **Knowledge Levels (<5 Minutes)**
    a. How comfortable are you with your knowledge about BC One Call?
        i. In terms of their services
        ii. In terms of the overall process in getting clearance to dig?
        iii. In terms of who operates BC One Call. *Explore relationship between BC One Call and FortisBC. Where does services from One Call start and stop vs. those of FortisBC.*
4. **Hits (20 minutes)**
    a. Has anyone you know, including yourself, ever "hit" anything before? What happened (*describe fully*)?
    b. What are the main reasons behind such hits? *Probe as fully as possible and going beyond inaccurate maps.*
    c. What could have been done to prevent the accident?
5. **Consequences (5 Minutes)**

a. What are the consequences of digging blind? What happens and how? *Probe for: financial damages; legal liabilities, business interruption to surrounding businesses; repair costs, others?*

6. Information (20 Minutes)

a. Do you recall any advertising from FortisBC? What were they about? Can you remember them? What about safety messages from FortisBC? Do you recall any of those? What ads do you recall from utilities overall. What did they talk about?

b. *Moderator plays FortisBC radio ads and asks:* Do you recall this message? Who sponsored this advertising? What is the message? Is it an effective message?

c. Is it important that **FortisBC** advertises about this topic? Why? Why not? If not FortisBC who else? Why them?

d. When it comes to overall information about excavating, where do you get your information? What kinds of information do you receive internally? Externally? Which communications do you prefer? Why?

e. Are there any barriers/anything preventing good communications that make dealing with them difficult? Easy? Why?

f. What sources do you prefer? Don't prefer? Why?

    i. Prompts: BC Common Ground Alliance; Public Works; Apprentice programs; unions; Industry Business Contractors Assn.; Others?

g. What kind(s) of information does FortisBC need to provide to you (*moderator creates list*). What kinds of information does FortisBC itself need to communicate? What kinds of impacts does FortisBC communications have on safe digging? How could they best compliment the efforts of BC One Call?

h. Which kinds of information are most vs. least important? Why?

i. What are the key messages that FortisBC needs to communicate? BC One Call?

    i. Prompts: Awareness of laws/regulations requiring organizations to use BC One Call/FortisBC; awareness of consequences; awareness of how to work with BC One Call.

j. What are the best ways to communicate each of these different topics to you? (e.g. Web vs. email vs. newsletter, etc.). Specifically to excavators?

k. How effectively does FortisBC communicate now? What kinds of communications are working well? Not working well? What would you recommend for them to do?

7. Communication Channels (20 Minutes)

a. What current communication channels does FortisBC currently use? BC One Call? If necessary prompt for:

    i. Word of mouth

ii. Print: community newspapers; mainstream press; magazines; newsletters; (recall: core message -> media -> message playback)
iii. Radio ads (recall: core message -> media -> message playback)
iv. Call centres
v. Internet (social media and Web)
vi. Languages (probe for most important: S. Asian; Chinese; Italian; Korean; others?)

b. Which ones need to be improved? Which ones should remain the same?
c. Focus on FortisBC Web site. Do you use it prior to digging? How? What is the quality of information? How easy is it to navigate?

8. Close

Attachment 166.7

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 184.1

FORTISBC ENERGY INC.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610
2	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897
3	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970
4	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714
5	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168
6	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588	5.869%	250,000	14,673
7	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,234	98,766	6.645%	100,000	6,645
8	2011 Medium Term Debt Issue - Series 25	9-Dec-2011	9-Dec-2041	4.250%	100,000	1,410	98,590	4.334%	100,000	4,334
9										
10	FEI 2015 Issue - Series A Renewal	30-Sep-2015	30-Sep-2045	5.150%	75,000	750	74,250	5.216%	75,000	3,912
11	FEI 2016 Issue - Series B Renewal	30-Nov-2016	30-Nov-2046	5.400%	157,274	1,573	170,634 *	5.468%	172,207	9,416
12	2017 Medium Term Debt Issue - Series 26	1-Jul-2017	1-Jul-2047	5.400%	200,000	1,500	198,500	5.451%	200,000	10,902
13										
14	LILO Obligations - Kelowna							6.563%	17,248	1,132
15	LILO Obligations - Nelson							8.539%	2,834	242
16	LILO Obligations - Vernon							9.912%	8,323	825
17	LILO Obligations - Prince George							8.750%	21,942	1,920
18	LILO Obligations - Creston							7.835%	2,106	165
19										
20	Vehicle Lease Obligation							2.274%	2,902	66
21										
22	Sub-Total								$ 1,772,562	$ 105,591
23	Less: Fort Nelson Division Portion of Long Term Debt								5,335	318
24	Less: NGT Class of Service Portion of Long Term Debt								10,224	609
25	Total								$ 1,757,003	$ 104,664
26										
27	*Includes adjustment of $14,933 for BC Hydro Premium (Series B).								Average Embedded Cost	5.96%
28										

Attachment 187.1

(Provided in electronic format only due to
document size and in order to conserve paper)

Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

March 28, 2013

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI") (collectively the "Companies") 2012 Year End Report for:

- **FEI-FEVI Main Extension ("MX") Report – British Columbia Utilities Commission (the "Commission") Order No. G-152-07 Compliance Filing; and**
- **FEI Vertical Subdivision Report – Commission Order No. G-6-08 Compliance Filing**

On October 16, 2012 in response to the FEI-FEVI Year End MX Report and FEI Vertical Subdivision Report (the "MX Report") filed for 2011, the Commission issued letter L-60-12, which found the report to be generally compliant. In the letter, the Commission also identified a number of enhancements that were to be included in the 2012 MX Report to improve the clarity and completeness of the MX Report.

In response to Commission Staff's requests, as identified in letter L-60-12, the Companies respectfully submit the attached 2012 MX Report. In addition to reflecting the format and methodologies utilized in the previously approved 2011 MX Report, the 2012 MX Report provides the requested enhancements and continues to comply with Orders No. G-152-07 and No. G-6-08.

We trust that the Commission will find the report in order and request confirmation from the Commission that the 2012 MX Report is in compliance with Orders No. G-152-07 and No. G-6-08. If there are any questions, please contact Mike Metza at 604-592-7852.

Yours very truly,

FORTISBC ENERGY INC.
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachment

FortisBC Energy Inc.
FortisBC Energy (Vancouver Island) Inc.

Main Extension Report for 2012 Year End

Compliance Filing in Accordance with Commission Orders No. G-152-07 and G-6-08

March 28, 2013

Table of Contents

List of Appendices

Index of Tables and Figures

1 EXECUTIVE SUMMARY

The Main Extension ("MX") report from FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI") (collectively called the "Companies") and the FEI Vertical Subdivision ("VSD") Report for 2012 Year End (collectively referred to as the "Report") are respectively filed in accordance with British Columbia Utilities Commission (the "Commission") Orders No. G-152-07 and No. G-6-08.

The primary findings in the Report are summarized below:

1. **The Companies are in compliance with the Commission reporting directives and continue to refine reporting practices based on Commission feedback.**

The 2012 MX Report continues to comply with and contains the requisite information in accordance with Commission Orders No. G-152-07 and No.G-6-08. The regulatory history section of this Report contains a detailed outline of the MX Report history. The 2012 MX Report format has been updated based on feedback received from Commission Staff while continuing to reflect the format and methodologies utilized in the previously approved 2011 MX Report.

2. **The variance in forecast versus actual main extension costs is reasonable.**

The Companies' methods of cost forecasting continue to provide a reasonable representation of actual project costs. Current forecasting methods capture an extensive scope of project-related expenses such as planning, materials and labour, and service line costs, which will generally have a higher level of variance when compared to mains cost due to the unique characteristics of individual lots. For the 2012 MX Report, the cost variances contained in this Report are reasonable as further demonstrated below.

3. **Attachments continue to follow economic conditions and are generally on track.**

Customer attachments to the Companies distribution system and the BC housing market are closely related and both are highly cyclical in nature. In general, the Companies work closely with a wide range of potential customers from homeowners to large developers to develop good-faith estimates of the consumption quantity and expected time of attachments on new main extension projects. However, similar to other utilities such as water and electricity, the Companies' forecasts are primarily affected by economic conditions and a multitude of other variables which can result in a misalignment of forecast and actual attachments. In most cases, unrealized attachments are simply delayed, and when considered beyond their respective forecast year, the majority of forecasted attachments will materialize. For the 2012 MX Report, the attachment variances relate closely to economic and housing market conditions and are generally on track or improving on an annual basis.

4. Actual consumption levels are consistent with new customers.

The Companies consumption forecasts used in the Main Extension test are based on the best available data at the time of formulation. The current methods draw forecasts directly from the actual consumption of all existing customers and are separated based on geographic region and appliance type. At the time of forecast, the expected annual consumption values derived by the Companies are accurate in that they are reflective of the existing customer base. However, the consumption patterns of new customers presented throughout the 2012 MX Report and previous reports have highlighted significant differences between new and existing customers. For the 2012 MX Report, the actual consumption levels are representative of new customers and the impacts current technological improvements and energy efficiency gains present in today's housing market; while the forecasted levels represent the consumption levels of all existing customers on the Companies distribution system who connected to the system in an entirely different environment.

5. The Company has provided a plan to address low aggregate Profitability Index ("PI") thresholds on a go-forward basis.

As a result, Commission Staff have required the Companies to come up with a "plan" to determine if the PI thresholds need to be adjusted on a go-forward basis in order to achieve the aggregate PI threshold of 1.1. In response to the Commission requirement detailed in letter L-60-12 issued on October 16, 2012, the Companies have attached as Appendix C, a detailed System Extension policy review with recommendations on how to improve the Companies' PI on a go-forward basis.In summary, the Companies will continue to apply the format and methodologies used in the 2012 MX Report for future reports as they are a direct result of suggestions by Commission Staff. The Companies also propose to develop a framework for System Extension policy enhancements through a collaborative effort with Commission Staff and Stakeholders based on the findings of the System Extension Policy review in Appendix C.

2 REGULATORY HISTORY

On July 31, 2007, FEI and FEVI[1] applied to the Commission for changes to the System Extension and Customer Connection Policies ("System Extension and Customer Connection Policies Review"). In December, 2007, the Commission issued Order No. G-152-07 and Reasons for Decision ("Order No. G-152-07") approving changes requested in the Companies System Extension and Customer Connection Policies Review. Commission Order No. G-152-07 established the parameters for the MX Test and the Companies were directed to file with the Commission an annual MX Report (page 37 of G-152-07):

> *"within 90 days of calendar year end, a Main Extension Report including the following:*
>
> - *a review of a random sampling of MX test results representing a confidence interval of +/- 12 percent at a 95 percent confidence level and the five highest cost main extensions to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1. The review is to include a comparison of forecast and actual costs; consumption; and PI for the first five years of main extensions in the sample;*
> - *a concise explanation of the random sampling methodology used; and*
> - *a comparison of the forecast and actual cost for all service line and main extension installations."*

Subsequently, FEI was directed to make revisions to the MX Test methodology and was further directed to provide information relating to Vertical Subdivisions under Commission Order No. G-6-08[2] issued on January 10, 2008:

> *"Terasen is directed include, in the Main Extension Report that Terasen was directed to file in the Commission's Main Extension Decision, the results of TGI's main extension tests to Vertical Subdivisions."*

The Companies applied the MX Test (also referred to as the "economic test" or "system extension test") as approved by the Commission to 2007, 2008 and 2009 main extensions, and filed the respective Main Extension reports in compliance with the requirements of Orders No. G-152-07 and No. G-6-08 on April 7, 2008, April 3, 2009 and April 10, 2010 respectively.

As a result of discussions with Commission Staff subsequent to the filing of the 2009 Report and a meeting with Commission Staff held on July 13, 2010, the Companies submitted a revised 2009 Report on August 18, 2010 with further information requested by Commission Staff. FEVI also submitted a detailed report for the Shawnigan Lake Main Extension, providing additional

[1] Then Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) Inc. (TGVI) respectively.

[2] Order No. G-6-08 was issued in response to an application by FEI (then TGI) to amend the general terms and conditions of its Tariff to allow an alternative method of providing gas service to Vertical Subdivision developments.

information and explanations for the performance of the Shawnigan Lake Main Extension based on then available information.

The Companies and Commission Staff continued their dialogue with respect to the MX Report via written correspondence, phone calls and a meeting on February 15, 2011, to review the compliance reporting requirements. As agreed with Commission staff, the Companies filed a draft report on March 31, 2011, prior to filing the final 2010 MX Report. The Companies then met with Commission Staff on April 12, 2011, and presented the findings contained within the draft report. Commission Staff provided comments on the draft report on April 20, 2011.

On June 1, 2011, the Companies filed the final 2010 MX Report, believing that the final 2010 MX Report was in full compliance with Orders No. G-152-07 and No. G-6-08.

On August 30, 2011, the Commission issued Letter No. L-67-11, which identified several issues for the Companies to address in the annual MX report. The Commission requested the Companies to:

- *Re-file within 45 days of the date of this Letter a fully compliant and informative 2010 MX Report in accordance with Commission Order G-152-07 and its Decision, Order G-6-08, and as clarified in this Letter L-67-11.*
- *File within 45 days of the date of this Letter meaningful and informative main extension performance updates on Sooke MX and Shawnigan Lake MX.*

An Addendum report to specifically address each issue identified in L-67-11 was filed October 14, 2011, referred to as the 2010 MX Report Addendum.

On March 22, 2012, the Commission issued Letter No. L-19-12, stating that the 2010 FEI and FEVI Year End Main Extension Report and the Addendum to the 2010 Main Extension Report still did not comply with the reporting requirements in Orders No. G-152-07 and No. G-6-08.

In order to have a clear understanding of the MX Report compliance requirements from the Commission's perspective and to provide an MX Report satisfactory to the Commission, including the MX Report format and methodologies, the Companies and Commission Staff met on March 28, 2012 and April 26, 2012. As a result of these discussions and further phone and email correspondence with Commission Staff, an agreed upon set of reporting tables and methodologies were developed to act as a framework for the 2011 MX Reports and future MX Reports.

On July 31, 2012, the Companies filed the 2011 MX Report, in full compliance with Orders No. G-152-07 and No. G-6-08. The report reflected the framework and methodologies developed as part of the previously mentioned meetings. A complete list of the updated reporting requirements is provided in the 2011 MX Report[3].

On October 16, 2012, in response to the 2011 MX Report, the Commission issued letter No. L-60-12 which found the report to be generally compliant. In the letter, the Commission also identified a number of enhancements that were to be included in the 2012 MX Report to improve the clarity and completeness of the Report. A brief summary of the reporting enhancements are as follows:

Letter L-60-12 Item	2012 MX Report Implementation
Consumption and Use Per Customer should be changed from a cumulative result to an annual result.	All tables in the 2012 MX report and future reports have been updated to reflect an annual consumption and use per customer breakdown as requested by Staff.
Provide a breakdown of attachments, consumption and use per customer segmented by rate class.	Given the complexity and resources required to gather this type of data, this change has been implemented on a go-forward basis. All new data tables including the 2012 cohort of mains will now reflect segmentation by rate class.
Include an explanation as to whether or not consumption Ramp-Up analysis was conducted.	Past practice has been to apply Ramp-Up on a per project basis at the planner's discretion. For those projects throughout this report that show a Ramp-Up factor of zero, the decision would have been made by the planner not to apply a Ramp-Up factor. On a go-forward basis, the Companies will provide an explanation where applicable. Also, to assist in ensuring a highly conservative Main Extension Test the Company has recently completed a new IT enhancement whereby all main extension projects will default to a minimum Ramp-Up value of at least 80 percent. This process was put in place on March 1st, 2013.
Include consumption Ramp-Up experience by rate class.	Ramp-Up is implemented on a per project basis only. Due to the difficulties in forecasting to such a granular level, the Companies do not conduct individual Ramp-Up analysis at the rate class or attachment level.
Include a plan to address low aggregate PI thresholds on a go-forward basis.	Please see Section 3 for a discussion of this requirement and refer to Appendix C of this report for a full and detailed response.

The 2012 MX Report has been updated to address Commission Staff's requests as identified in Letter No. L-60-12, which are outlined above. Also, based on the direction received from Commission Staff, the 2012 MX Report continues to reflect the format and methodologies

[3] FEI & FEVI Main Extension Report for 2011 Year End, submitted on July 31, 2012 – Section 1, p10.

utilized in the previously approved 2011 MX Report. All tables, charts, and calculations contained in the 2012 MX Report are reproductions of previously agreed upon designs which have been revised with updated figures. Also, as seen in Table 1 below, the 2012 MX Report continues to comply with and contains the requisite information in accordance with Commission Orders No. G-152-07 and No. G-6-8.

Table 1: Reporting Requirements Met by the Companies

Order Number	Compliance Reporting Requirement	Report Page Reference #
G-152-07	Provide schedules comparing the existing and updated geo-codes and MX Test input parameters.	pp.20-27
G-152-07	Update FEVI MX test to reflect FEVI use per appliance.	pp.24
G-152-07	Reflect in the Companies' MX tests their experience of the consumption ramp-up in the early months of service.	pp.32-116
G-152-07	Comparison of forecast and actual costs, consumption and PI for the first five years of main extensions in the sample.	pp.32-116
G-152-07	A concise explanation of the random sampling method used.	pp.19-20
G-6-08	Confirm that it reflects, in the MX test inputs, the fact that larger developments may require several years before all units are occupied an normal consumption patterns are established.	pp.32-116
G-6-08	The results of FEI's main extension tests to Vertical Subdivisions.	pp.32-116

The 2012 MX Report is organized in the following manner:

Exploration of PI and EES Whitepaper Introduction: Section 3 below provides a summary of the issues surrounding the historically low PI results as well as the framework for the analysis undertaken on the Companies' System Extension Policies attached as Appendix C and titled "FortisBC Energy Utilities Review of System Extension Policies". The information found in Appendix C and outlined in Section 3 is in response to the Commission requirement in Letter No. L-60-12 to include a plan to address the low aggregate PI thresholds as identified in previous Main Extension Reports, on a go-forward basis.

MX Test and Parameter Details: At the request of Staff, the 2012 MX Report provides detailed information on the Companies' Main Extension Test calculations with accompanying data tables comparing annual MX Test parameter updates for each reporting cohort year retroactive to 2008.

Review of Forecasting Methodologies: The 2012 MX Report also repeats an in-depth discussion on the methodologies and challenges relating to the forecasting of inputs used in every Main Extension Test.

Presentation of Results and Conclusion: An annual break down of Main Extension Test results tables is presented in Sections 6 to 10. The tables have been designed in conjunction with Commission Staff and are organized by reporting cohort year.

3 EES CONSULTING LTD. AND THE SYSTEM EXTENSION POLICY WHITEPAPER

3.1 Purpose of Engagement

In the case of the 2012 MX Report and the Commission requirement to formulate a plan to address the low PI thresholds on a go-forward basis, the Companies have engaged EES Consulting to provide research, analysis and recommendations on system extension policy options to assess the appropriateness of PIs on a go-forward basis. Additional prerequisites are also to ensure any recommendations will not adversely affect existing customers, while at the same time continue to promote the use of natural gas as a clean and economical energy source by minimizing any barriers to connection for new customers connecting to the Companies' distribution system for the first time.

EES Consulting Ltd. ("EES Consulting") is a multidisciplinary management consulting firm with particular expertise in Rate Design methodology and Cost of Service Allocation modelling, previously retained by the Commission, FortisBC Inc. and FEI for the validation of rate design methodologies and models. EES Consulting is familiar with the FortisBC Energy Utilities' ("the FEU[4]") business and has been retained by the Companies on an ad-hoc basis for several years.

3.2 Understanding the Profitability Index

Previous Main Extension Reports have shown the aggregate PI for both FEI and FEVI to be below the 1.1 threshold outlined in Order No. G-152-07. As a result and as part of the 2012 MX Report, Commission Staff have required the Companies to come up with a "plan" to determine if the PI thresholds need to be adjusted on a go-forward basis in order to achieve the aggregate PI threshold of 1.1.

Although the Companies recognize the importance of assessing each main extension project before it begins to better understand the potential effects on existing and new customers, there remains considerable question around the use of the PI as the measure of performance of projects and the Companies themselves, especially when taken within the context of the Companies' annual Main Extension Report. The PI contained in the MX Reports should be viewed as a snapshot in time only. In fact, due to the five-year reporting structure, many results reviewed by the Commission should only be considered to be preliminary in nature as they are highly vulnerable to economic conditions which will significantly raise or lower the PI of a new main extension simply based on present housing market demand levels and the re-forecasting methodologies required by the Commission. As will be seen throughout the results of this MX Report, the majority of main extensions continue to add customers year after year. However, these actual attachments are, in most cases, misaligned with original forecasts due to the difficulties in determining exactly when a home in a given subdivision will be planned, constructed, sold and the meter activated. These ongoing and potential future customer

[4] The FEU consist of FEI, FEVI and FortisBC Whistler Inc.

connections support the notion that the PI at any given time on an existing main is generally representative of that point in time only. When considered in conjunction with re-forecasting methodologies where unrealized attachments are assumed to have disappeared forever, the PI becomes even less representative of the long-term potential economic benefits to customers.

The current MX Test itself is also structured in such a way that it lends itself to being viewed as a short-term measure based on the maximum twenty-year discounted cash flow of all main extension projects. Because the vast majority of the Companies' assets last well beyond twenty years, the MX Test does not accurately portray the final, economic impact of a main extension project on rate payers as it assumes customers simply disappear from the FEU systems at the end of twenty years. In reality, many customers' homes at this time are undergoing renovations or their neighbourhoods are undergoing renewal. A prime example would be the demographic shift in Vancouver's residential neighbourhoods where coach homes are being added in addition to existing single family dwellings. This represents unanticipated additional consumption on a pre-existing main and would translate into an improved PI, well after the twenty year PI calculated in the Companies' current Main Extension Test. Furthermore, many main extensions spawn additional main extensions which are not translated back, or have an effect on, the original system extension (due to the current five year window of forecasting attachments). This additive effect can serve to make original main extensions even more positive than would be shown in current reporting. Therefore the only way to truly asses the viability of a main extension is at the end of life of the economic period.

3.3 EES System Extension Policy Review

The Companies intend to use the recommendations from EES Consulting to form the framework for a proposed System Extension policy review to support higher PI's for new main extension projects on a go-forward basis in relation to the issues discussed above. The EES report found in Appendix C, titled "FortisBC Energy Utilities Review of System Extension Policies" provides the following information:

- Analysis of existing FEU main extension policies
- Identification of issues within current FEU policies
- Review of alternative methods and final recommendations.

3.4 System Extension Policy Review Process Objectives

The Companies propose the following preliminary schedule as an outline of how the Companies propose to engage with Commission Staff and our Stakeholders regarding the review of the MX Test policies recommendations outlined above:

- 2012 MX Report Submission March 31, 2013;
- Initial meeting between the Companies and Commission Staff early April 2013. The purpose of this meeting is to review the results of the Report and begin to identify Stakeholders and a process to review the System Extension policies; and

- Engagement of applicable Stakeholders, Staff and the Company will follow. This engagement will include educational workshops to review the relevant issues and develop a go forward plan.

The above list is intended to provide a preliminary framework only and can be refined and updated based on discussion with Commission Staff and potential Stakeholders once initial reviews of this material are completed.

4 MAIN EXTENSION TEST METHODOLOGY

The following section summarizes the formula for the MX Test, the inputs into the 2012 MX Test and the methodology used to present the results of the 2012 MX Report.

For background, the Companies have provided in Appendix A and Appendix B the applicable Definitions and Section 12: Main Extension of the FEI General Terms & Conditions ("GT&Cs"). The relevant terms found in these appendices apply throughout the 2012 MX Report. In addition, the Companies have also provided a set of comprehensive data for the years 2008 to 2012 for each of the MX Test parameters tables discussed in this section. Although the focus of the 2012 MX report is based on a comparison of the 2012 versus 2011 gas year, the Companies have included past year's data for reference purposes pursuant to the agreed upon methodology with Commission Staff.

4.1 Main Extension Test Formula

All applications to extend the gas distribution system to one or more new customers are subject to an MX Test approved by the Commission. The MX Test formula develops a PI which is the ratio of the discounted present value of all forecast net cash inflows over twenty years divided by the discounted present value of the capital costs of attaching customers in the first five years of the main extension.

While there are many components factored into the calculation of this ratio, the following formula provides a summary of the major components:

$$\textbf{P.I.} = \frac{\substack{\textbf{Net Present Value of Net Cash Inflows} \\ \text{(Delivery Margin + Connection Fees – O\&M - System Improvement Charge – Property Tax – Income Tax)}}}{\substack{\text{(Mains, Services, Meter Costs)} \\ \textbf{Net Present Value of Capital Costs}}}$$

Accompanying the MX Test formula are the following FEI and FEVI MX Test threshold criteria that have been approved by the Commission under Order No. G-152-07:

- If an individual PI is 0.8 or greater, the system extension can proceed without the need for a customer contribution.
- If the PI is less than 0.8, a customer contribution is required to bring the PI up to the 0.8 threshold, before the system extension can be built.
- An aggregate threshold PI of 1.1 is to be used for the portfolio of main extensions completed on an annual basis.

4.2 Re-Forecasted PI Calculation Methodology

The re-forecasting methodology used when calculating the updated PI of a main extension has a significant impact on the results contained in this Report. After the submission of the 2010 MX Report, the Commission issued Letter No. L-67-11 which found the Companies method of re-forecasting un-realized attachments to future years insufficient when calculating the re-forecasted PI of a main extension.

Following discussions with Commission Staff, it has been agreed that the Companies will not perform a re-forecasting of unrealized attachments when re-forecasting the PI of a main extension. For example, if a particular project has 50 attachments forecasted for both year 1 and year 2, and the actual year 1 and year 2 attachments figures are 0 and 50 respectively, then the re-forecasted PI calculation would only be based on one half (50 out of 100) of the planned attachments, with the assumption that the other 50 attachments would simply never occur. *Although this may provide a clear and consistent methodology, it will result in a re-forecasted PI that is less representative of the final PI of the project.* In this case, un-realized attachments may simply be deferred for economic reasons or project related complications and could arise in future years lending support to viewing the actual PI calculation as a “snap shot” in time only.

Furthermore, the MX Test applicable to all mains extensions contains both forecasted consumption and attachment figures for a full twenty years after the anticipated install date of the main; therefore a comparable measure of a project’s forecasted PI versus actual PI can only be realized after a full twenty years have passed. The five-year time horizon is only relevant for reporting purposes. *The annual MX reports provided to the Commission thus represent a “snap shot” in time view of a main extension or group of main extensions out of the 20 year discounted cash flow (“DCF”) time frame*. As discussed earlier, the time horizon for measuring the economic benefits of a project lie beyond 20-year DCF and are better equated to the life of the assets themselves. The BC housing market and the Companies’ attachment and consumption results are closely related and cyclical in nature. Inevitably, there will always be uncertainty and variability from year to year inherent in forecasting attachments, despite the Companies’ best efforts to apply their industry knowledge, experience and conservative approach to forecasting. The risk of focusing on performance of an individual year is that attachments that did not materialize in a given year may do so at some point in the future of the 20-year DCF time frame. Furthermore, over the 20-year timeframe, there may be attachments that materialize that were not originally forecast by the Companies. In summary, the performance of main extensions in aggregate cannot be fairly evaluated until, at the earliest, the end of the 20-year DCF timeframe.

Both FEI and FEVI currently use the same DCF test to evaluate main extensions; however, the inputs for the tests vary between each utility. A discussion of the net cash inflow, capital cost and discount rate inputs into the MX Test formula for each utility is provided in Section 2.4.

4.3 Main Extension Data

This section outlines the methodology used to establish the relevant main extension sample data sets along with the cost and consumption data provided in the 2012 MX Report.

The 2012 MX Report contains main extension projects that have been organized using the following methodology:

2012 Mains - Contain main extensions for the 2012 gas year (Nov-Oct) including forecasted attachments and consumption data and a comparison of the forecasted and actual mains costs only. The first year of actual attachments and consumption data for this set of mains will be presented in the 2013 MX Report. This group of mains will be updated in each annual MX Report over the next five years, from 2013 to 2017.

2011 Mains - Contain main extensions for the 2011 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and mains costs from November 1, 2010 to October 31, 2011. The results in this report reflect Year 1 of actualized data for this group of mains. 2016 will be the final year of reporting for this set of mains.

2010 Mains - Contain main extensions for the 2010 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and mains costs from November 1, 2009 to October 31, 2011. The results in this report reflect Year 2 of actualized data for this group of mains. 2015 will be the final year of reporting for this set of mains.

2009 Mains - Contain main extensions for the 2009 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and mains costs from November 1, 2008 to October 31, 2011. The results in this report reflect Year 3 of actualized data for this group of mains. 2014 will be the final year of reporting for this set of mains.

2008 Mains - Contain main extensions for the 2008 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and mains costs from November 1, 2007 to October 31, 2011. The results in this report reflect Year 4 of actualized data for this group of mains. 2013 will be the final year of reporting for this set of mains.

The 2008-2012 main extension sample data sets were determined based on the following criteria:

1. All main segments in a particular data set must be installed after November 1st.
2. All main segments within a main extension project must be fully installed or "technically complete" ("TECO'd") prior to October 31st.

The Companies are using a random sampling methodology for all data included in the 2012 MX Report as per Order No. G-152-07. As a result, the 2012 FEI and FEVI populations consist of 285 and 54 completed mains respectively, with a random sample size of 85 and 38 respectively. The data sets for the 2008-2011 gas years have been previously reported and are also based on the random sample method; and as such, all data tables contained in this report are based on the same random sample method. The random samples were determined by calculating a statistical sample size which meets the criteria discussed in Section 2 and then extracting that sample from the populations for each annual data set that met the conditions discussed above.

As stated in previous MX reports, historical main extensions will be reported until the end of the five year period, for example, through to October 31, 2013 for 2008 projects and will include costs, attachment, consumption and PI variance both in aggregate and the top 5 mains for both FEI and FEVI.

4.4 Main Extension Test Parameters

This section provides tables containing details on the parameters used in the Main Extension Test. The focus of reporting is a comparison of 2012 versus 2011 parameters; however, historical parameters have been included at the request of Commission Staff.

4.4.1 NET CASH INFLOWS

As discussed above, net cash inflows are composed of the delivery margin plus connection fees, less O&M, a system improvement charge, property tax, and income tax. Each of these components is outlined in the following section.

The projected gross delivery margin for an entire main used in the economic test is determined as follows:

a) estimating the number of customers to be served by the main extension[5];
b) establishing consumption estimates for each customer (discussed in the next section);
c) projecting when the customer will be connected to the main extension; and
d) applying the appropriate delivery margin for each customer's consumption.

In the case of FEVI, an effective delivery margin is calculated by subtracting the unit cost of gas from the sales rate. The FEVI sales rate has remained relatively constant throughout the periods covered by the 2010-2011 and 2012-2013 Revenue Requirements Applications (RRAs).[6, 7, 8, 9] The basic and delivery charges, the in lieu rate and new service fee data are as follows:

---

5 Only those customers expected to connect to the main extension within 5 years of the completion are considered.

6 Up to December of 2011, the unit cost of gas includes royalty credits. Including the royalty credits in the cost of gas results in a derived delivery rate that more closely resembles the gross margin of FEVI.

7 FEI Basic and Delivery Charges – "Fortis BC Energy Inc. General Terms and Conditions, Rate Schedule 1, first revision of page R-1.1; Rate Schedule 2, first revision of page R-2.1; Rate Schedule 3, first revision of page R-3.1.)"

8 FEVI Basic and Delivery Charges – "Terasen Gas (Vancouver Island) Inc., Standard Terms and Conditions and Rates for Gas Service, first revision of pages C-2 to C-7 and page C-11".

9 FEI New Service Fees – "FortisBC Energy Inc. General Terms and Conditions", page S-1. As per Commission order no: G-28-11. FEVI New Service Fees – "Gas (Vancouver Island) Inc., Standard Terms and Conditions and Rates for Gas Service", page C-1 as per Commission order G-30-11.

Table 2: Basic & Delivery Charges, In Lieu Rate & New Service Fee

	2008				2009				2010				2011				2012			
Rate Class	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)
FEI																				
Rate 1	$133.56	$2.78	3.22%	$85.00	$143.88	$3.00	2.97%	$85.00	$142.08	$3.18	2.55%	$25.00	$142.08	$3.28	2.51%	$25.00	$142.08	$3.56	2.23%	$25.00
Rate 2	$280.20	$2.33	3.95%	$85.00	$301.80	$2.51	3.70%	$85.00	$298.08	$2.64	3.11%	$25.00	$298.08	$2.71	3.07%	$25.00	$298.08	$2.93	2.63%	$25.00
Rate 3/23	$1,469.76	$2.01	3.60%	$85.00	$1,610.40	$2.16	3.36%	$85.00	$1,590.24	$2.26	2.87%	$25.00	$1,590.24	$2.32	2.85%	$25.00	$1,590.24	$2.48	2.40%	$25.00
FEVI																				
RGS	$126.00	$5.90	2.11%	$85.00	$126.00	$4.49	2.08%	$85.00	$126.00	$7.69	2.84%	$25.00	$126.00	$8.29	2.81%	$25.00	$126.00	$8.00	1.60%	$25.00
SCS-1	$113.40	$8.44	1.86%	$85.00	$113.40	$7.10	1.87%	$85.00	$113.40	$10.30	2.40%	$25.00	$113.40	$10.90	2.40%	$25.00	$113.40	$10.61	1.57%	$25.00
SCS-2	$402.36	$7.71	1.93%	$85.00	$402.36	$6.62	1.93%	$85.00	$402.36	$9.82	2.55%	$25.00	$402.36	$10.42	2.55%	$25.00	$402.36	$10.13	1.83%	$25.00
LCS-1	$732.00	$4.79	2.49%	$85.00	$732.00	$3.51	2.54%	$85.00	$732.00	$6.71	4.15%	$25.00	$732.00	$7.31	4.15%	$25.00	$732.00	$7.02	1.83%	$25.00
LSC-2	$1,173.84	$3.82	2.90%	$85.00	$1,173.84	$2.47	3.02%	$85.00	$1,173.84	$5.67	6.22%	$25.00	$1,173.84	$6.27	6.22%	$25.00	$1,173.84	$5.98	2.01%	$25.00
LCS-3	$2,418.12	$3.56	3.16%	$85.00	$2,418.12	$2.18	3.39%	$85.00	$2,418.12	$5.38	8.47%	$25.00	$2,418.12	$5.98	8.48%	$25.00	$2,418.12	$5.69	2.08%	$25.00
AGS	$480.00	$3.89	2.91%	$85.00	$480.00	$2.53	3.06%	$85.00	$480.00	$5.73	6.23%	$25.00	$480.00	$6.33	6.23%	$25.00	$480.00	$6.04	1.98%	$25.00

Additional inputs into the net cash inflows calculation are shown below:

Table 3: Net Cash Inflows Economic Parameters[10]

Economic Parameter	FEI 2008	FEI 2009	FEI 2010	FEI 2011	FEI 2012	FEVI 2008	FEVI 2009	FEVI 2010	FEVI 2011	FEVI 2012
O&M per Customer										
Residential	$75.00	$75.00	$75.00	$86.00	$84.00	$62.48	$62.48	$62.48	$70.00	$74.00
Commerical	$98.00	$98.00	$98.00	$89.00	$87.00	$86.48	$86.48	$86.48	$85.00	$90.00
System Improvement (SI)	$0.16	$0.16	$0.16	$0.16	$0.36	$0.15	$0.15	$0.15	$0.15	$0.49
Property Tax Rate	1.85%	1.96%	1.96%	1.95%	2.01%	1.80%	1.71%	1.81%	1.86%	1.90%
Income Tax Rate	31.50%	30.00%	28.50%	26.50%	25.00%	31.50%	30.00%	28.50%	26.50%	25.00%

Notes:

- O&M per customer figures for 2012 are from the 2012-2013 RRA.[11]
- Property tax rates are based on actual property tax payments. The changes in income tax rates reflect those included in the RRA.

4.4.2 SYSTEM IMPROVEMENT CHARGE & METHODOLOGY

Prior to 2012, the System Improvement ("SI") charge was calculated once every 5 years; the last SI charge calculation took place in 2007 and was approved in Order G-152-07 along with the methodology to re-visit the SI charge every 5 years. The resulting SI charges for FEI and FEVI of $0.16 per GJ and $0.151 per GJ respectively were applied to all Main Extension Tests from 2007-2011. As agreed upon with Commission Staff, the Companies will be re-calculating the SI charge on an annual basis in order to better capture the changing consumption patterns of customers and to reflect the resulting variability in peak day demand which forms the foundation for the SI charge calculations. Although the calculation methodologies behind the SI charge will remain consistent with past practices, the Companies are in agreement with Commission Staff that re-calculating the SI charge each year will not only reduce vulnerability to forecast error, but will ensure customers are charged a rate that is continuously refined to reflect the current state of the Companies' distribution system. Table 4 below identifies the variances between the 2007/2011 SI charge and the 2012 SI charge.

[10] For this table, FEI Commercial is defined as Rate Schedule 2 and FEVI Commercial applies to all sales customers excluding Residential (RGS)

[11] The FortisBC Energy Utilities 2012- 2013 Revenue Requirements and Rates Application (Commissions approval order G-44-12).

Table 4: SI Charge Calculation

Changes from 2007 - 2011 to 2012 SI Charge

		FEI	
		2007 - 2011	**2012**
A	**Increase to Peak Day over 5 years**	89.5	45.2
B	**System Improvement**	$ 17,209,119	$ 16,160,000
C	**Investment Cost per GJ of Peak Capacity** = B / (A x1000)	$ 192.28	$ 357.41
D	**5 Year Average Load Factor**	0.292	0.245
E	**Investment Cost per GJ of Annual Capacity** = C / (365 x D)	$ 1.80	$ 4.00
F	**Carrying Cost per $1,000**	$ 88.83	$ 88.97
G	**Levelized Cost/GJ** = E x (F / 1000)	**$ 0.160**	**$ 0.355**

		FEVI	
		2007 - 2011	**2012**
A	**Increase to Peak Day over 5 years**	17.4	9.4
B	**System Improvement**	$ 3,398,787	$ 5,550,000
C	**Investment Cost per GJ of Peak Capacity** = B / (A x1000)	$ 195.33	$ 588.82
D	**5 Year Average Load Factor**	0.302	0.281
E	**Investment Cost per GJ of Annual Capacity** = C / (365 x D)	$ 1.77	$ 5.74
F	**Carrying Cost per $1,000**	$ 85.08	$ 84.55
G	**Levelized Cost/GJ** = E x (F / 1000)	**$ 0.151**	**$ 0.485**

For the 2012 Main Extension Test, the SI charge was recalculated and resulted in SI charges of $0.36 per GJ and $0.49 per GJ for FEI and FEVI respectively.

The major driver of the change from 2007/2011 to 2012 is the reduction in the "Forecast Increase to Peak Day over 5 years". The Companies' System Planning department uses a forecasted "peak hour" demand to size the system to meet the hourly demand of gas. The "peak hour" demand is then used to determine the system improvement capital. With the installation of newer energy efficient and on-demand heating equipment the actual peak hour flows will likely creep upwards however, the total peak day demand will likely decrease as non-peak hours will use less gas.

The resulting implications are that the system improvement capital does not change significantly but when divided by the lower peak day demand, the investment per GJ of peak day demand increases resulting in a higher SI Charge.

The system improvement capital can also be impacted by the geographical location of the anticipated system expansion requirements. Overall, demand may be down, but the new customers that are being added may be at the edge of the system, and as a result, the Companies would incur more system improvement capital per customer for expansion in outlying areas as compared to previously settled areas.

4.4.3 CONSUMPTION

Consumption is calculated by determining the annual usage estimates by appliance type derived from operational experience and the Companies' own Residential End Use Study ("REUS"). The consumption figures for 2011 are based on the 2008 REUS which included a regionalized approach to forecasting consumption where usage amounts per appliance are based on the geographic location of a potential customer. The consumption values for 2008 to 2010 are reflective of the 2002 REUS, which assumed a single set of consumption per appliance parameters regardless of location. This data is presented in Table 4.

Table 5: Appliance Use Inputs for MX Test

Appliance	2008 - 2010 (GJ/yr)	2011-2012 (GJ/yr)		
	All Regions	Lower Mainland	Interior	Vancouver Island
Barbeque	3.1	3.1	3.1	3.1
Boiler	60.0	62.0	51.6	43.0
Clothes Dryer	4.0	4.2	3.6	3.4
Fireplace - Décor	15.8	18.3	15.9	16.1
Fireplace - Heating	16.8	21.4	19.8	19.7
Furnace (primary)	60.0	62.0	51.6	43.0
Furnace (secondary)	60.0	18.1	39.3	19.9
Hot Tub	17.9	19.5	19.5	19.5
Hot Water Tank	20.8	20.4	18.8	18.8
Pool	53.5	38.5	38.5	38.5
Range/Cooktop	8.5	5.6	5.1	4.7
Wall Heater	18.1	7.1	7.1	7.1

Notes:

- Customers who install both high efficiency gas fired space and water heating receive a credit of 10 percent of the volume otherwise used for both appliances.
- Customers who install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification receive a credit of 15 percent of the volume otherwise used for both.

As per Commission Order No. G-6-08, the Companies are required to confirm that some larger developments, including vertical subdivisions, may require several years before all units are occupied and normal consumption patterns are established. This is accounted for in the forecast. Various considerations go into meeting this requirement including accounting for economic conditions, project forecast from builder/developers and the Companies' expertise and experience in these areas.

As per Commission Order No. G-52-07, the Companies note that consumption "ramp up" is present in their aggregate forecasts. Specifically, the Companies build into selected year 1 consumption forecasts a 'ramp up' factor that reduces year 1 forecasts. The Companies and Commission Staff have agreed that the general use of the 'ramp up' factor, as well as its magnitude, is solely at the discretion of the planner and energy sales expert. The 'ramp up' tool is an option to assist the sales and planning groups with the potential to increase the accuracy of their forecasts. As requested by Commission Staff, the Companies have provided the associated 'ramp-up' factor for each of the top 5 main extensions for both FEI and FEVI.

4.4.4 CAPITAL COSTS

The inputs into the net present value of capital costs in the MX Test formula are discussed in the following section. The capital costs to be used in the economic test are described in Section 12.5(a) and 12.5(b) of the FEI and FEVI GT&Cs (refer to Appendix B).

4.4.4.1 Geo Codes and Manual Estimates

Geographic ("Geo") code and manual estimate pricing are the two methods used to determine main extension costs with approximately 10 percent of MX projects using the manual estimate cost methodology.

The following table illustrates the criteria used by the Companies to determine the requirement to use geo code versus manual estimates.

1 **Table 6: Geo Code & Manual Estimates Criteria**

Pipeline Criteria	Geo Code	Manual Estimate
Pressure	Distribution pressure (DP)	Intermediate pressure (IP)
Material	Polyetheleyne (PE)	Steel (ST)
Diameter	Up to 60 mm (2")	88 mm (3.5") and larger for PE and ST
Length	Maximum 1000 m	Greater than 1000 m
Cost	Maximum $100,000	Greater than $100,000
Crossing Type	Road or pipeline only	Direction drills, highway, bridge, water or railway crossing
Environmental impacts	All environmental impacts except fish bearing streams	Environmental impacts of fish bearing streams
Other		Vertical Sub Divisions Conversion Mains Mains in transmission right of ways

2

3

4 Recent geo codes and manual estimate inputs used in the MX Test are as follows:

Table 7: Geo code & manual estimate parameters

	Geo Code & Manual Pricing ($/metre)						
		PE Pipe ($/m)			Steel Pipe ($/m)		
	Zone	Up to 60 mm	88 - 114 mm	168 mm	Up to 60 mm	88 - 114 mm	168 mm
2012	Vancouver & Richmond	$65					
	North Shore & Squamish	$55					
	North of Fraser River	$51					
	South of Fraser River	$43	manual			manual	
	Interior North	$31					
	Interior South	$29					
	Vancouver Island	$50					
2011	Vancouver & Richmond	$65					
	North Shore & Squamish	$56					
	North of Fraser River	$43					
	South of Fraser River	$42	manual			manual	
	Interior North	$33					
	Interior South	$23					
	Vancouver Island	$55					
2010	Vancouver & Richmond	$83	$141	$227	$208	$353	$566
	North Shore & Squamish	$55	$94	$150	$138	$234	$375
	North of Fraser River	$56	$95	$153	$140	$238	$382
	South of Fraser River	$47	$80	$128	$118	$200	$321
	Interior North	$35	$60	$96	$88	$149	$239
	Interior South	$26	$44	$71	$65	$111	$177
	Vancouver Island	$50	$85	$137	$125	$213	$341
2009	Vancouver & Richmond	$59	$84	$162	$148	$211	$405
	North Shore & Squamish	$54	$77	$148	$136	$192	$370
	North of Fraser River	$62	$88	$169	$154	$219	$422
	South of Fraser River	$40	$56	$108	$99	$140	$270
	Interior North	$27	$39	$74	$68	$96	$185
	Interior South	$28	$40	$77	$71	$101	$193
	Vancouver Island	$61	$87	$167	$153	$218	$419
2008	Vancouver & Richmond	$58	$99	$158	$145	$247	$394
	North Shore & Squamish	$60	$103	$165	$151	$258	$412
	North of Fraser River	$40	$68	$109	$100	$170	$272
	South of Fraser River	$40	$69	$110	$101	$172	$275
	Interior North	$26	$44	$71	$65	$111	$177
	Interior South	$26	$44	$71	$65	$111	$177
	Vancouver Island South	$66	$113	$181	$166	$284	$453
	Vancouver Island North	$41	$70	$111	$102	$174	$279

Notes:

- The geo code variance in the table above is attributable to the use of linear regression on historical main extension cost data (geo codes are derived by performing linear regression on historical cost data).

The capital cost portion of the MX Test formula includes economic parameter inputs used for all rate classes. The relevant parameters are summarized below:

Table 8: Capital Cost Economic Parameters

	FEI					FEVI				
Economic Parameter	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
Overhead Rate	32.00%	32.00%	32.00%	30.00%	27.40%	32.00%	32.00%	32.00%	30.00%	27.40%
CCA Class 1	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Working Capital Rate	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%

Notes:

- As seen above, in 2012 the Companies updated the applicable overhead figures to reflect data available from the RRAs. This overhead rate represents applicable costs required in support of new mains activities and is reflective of the Companies' current cost structure and overhead capitalization.

4.4.5 DISCOUNT RATE

The discount rates used for 2012 were 5.0 percent for FEI and 4.6 percent for FEVI. The discount rates reflect the capital structure of each company and the relative borrowing costs and allowed ROE (Commission Order No. G-44-12), as per the Companies' respective RRAs. For each year, the discount rates were adjusted to real dollars using an inflation factor of 2 percent.

The following section provides discusses the methodologies and challenges associated with the three pillars of the MX Test, consumption, attachments and costs.

5 MAIN EXTENSTON TEST FORECASTING METHODOLOGIES

The Companies place paramount importance on incorporating fair and reasonable forecasting methodologies used in the Main Extension Test. The Companies are committed to effectively managing the inherent variability between forecast and actuals of the three cornerstones of the PI calculation, namely consumption, attachments and cost. This section provides a high level summary of the challenges faced when attempting to forecast consumption, attachments and cost and the Companies' efforts to manage the variability. This section also serves as an introduction to the significant volume of data that follows and provides an efficient overview of common themes that apply to MX projects in general.

5.1 Customer Consumption

The individual consumption pattern of each customer attaching to a particular main extension contributes greatly to the variance between the forecast and actual consumption of a main extension. For example, although a developer may plan to install identical appliances for each home in a subdivision, the individual customers who purchase those homes will have their own unique usage patterns which add to the uncertainty in forecasting. In addition, the type of appliances installed can also result in differences between forecasted and actual consumption of each customer. A convenience hookup such as barbeque may have a wider consumption variation between customers than two customers that have a primary heat source appliance such as a furnace (assuming those premises are not vacation properties or properties that also have other sources of heating). The Companies also have very little control over fuel switching, where a customer may choose to easily install an electric fireplace in a high usage room rather than utilize the furnace to heat the entire home. Finally, in a main extension project where there is a mix of both residential and commercial customers, the actual consumption figures and use per customer would be subject to significant variation from the forecast if just one of the larger commercial customers fails to connect given that the usage of a large business is generally much greater than several single-family dwellings.

Neither builders nor the Companies have control over the usage rate of the end use customer. Builders only have control over the installation of the natural gas appliance. *The usage rates of new end-users can be highly variable. Similarly, existing customers change their load and usage profiles over time as a result of changing equipment or moving from one form of energy to another for a specific appliance (i.e., electric stove to gas stove or vice versa) or through the changing demographics of the household in the event the home is re-sold*. These existing customers are not penalized for changing their load profiles; on the contrary, through Energy Efficiency and Conservation Programs ("EEC"), these customers are actually encouraged to use less than what they previously used. In this manner, it is inconsistent, and unequal from an intergenerational standpoint, to hold new customers/developers to a different standard than existing customers.

In the past, when performing the MX Test, the Companies have utilized a single average consumption value (dependent on the appliances) for each connection based on results from the 2002 REUS. However, the 2008 REUS included findings that prompted the Commission's decision to direct the Companies to move to a regionalized approach to consumption, where a customer's forecasted consumption would be contingent upon their appliances as well as where they lived and was based on the average consumption of all existing customers at that time. In Table 4 for example, the appliance use inputs for 2008-2010 years are based on 2002 REUS where 100 GJs of annual consumption would have been considered normal usage for a customer with a furnace, hot water tank and a fireplace regardless of where they lived. However, the 2008 REUS regionalized approach adopted in 2011, resulted in a reduction for a typical Vancouver Island resident to 75 GJs per year. This change in methodology has been in place since 2011 and will be reflected in the results of future MX Reports.

A primary deliverable of the 2012 REUS, which is currently underway, will be an in-depth analysis of the regional consumption forecasting methods currently employed by the Companies. For example, the consumption pattern of a new customer compared to current customer with the same appliances will differ because of continuously improving technology and energy efficiency. It is anticipated that the 2012 REUS will show a decline in the regionalized appliance-based consumption patterns of the average FEI and FEVI residential customer based on the addition of new energy efficient customers over the past few years. The Companies will be working through the analysis phase of the 2012 REUS data throughout the second and third quarter of 2013, with final results anticipated to be ready for review during the fourth quarter of 2013.

The Companies residential consumption forecasts are based on the best available data available at the time of formulation, and as such, will be updated based on feedback and approval from Commission Staff on the findings of the 2012 REUS. *However, even with a more robust REUS, the Companies continue to believe that there will be a disconnect between new and existing customers in terms main extension test inputs such as consumption, PI results, and overall policy impacts.*

5.2 Attachments

The primary contributor to the cash inflows of the Main Extension Test is the number of attachments or "services", and their related consumption levels. It is important to note, however, that without associated consumption, a service attachment contributes only to the cost portion of a main extension. For example, if a developer had built and attached new homes to the system, and, due to economic conditions, faced delays in selling those homes, the PI, at that snapshot in time moment, of the main extension would actually be lower than if the homes had not been built at all. In other words, the costs incurred by the Companies for the service connections would not yet be offset by consumption.

In general, the developer provides a good-faith estimate of the future attachments and appliances to be installed in a main extension project. The developers use their knowledge and experience, along with FEI/FEVI knowledge and experience to finalize these forecasted customer/appliance attachments. However, in certain instances where there is concern over the forecasts, a security deposit may be obtained from the developer (as per GT&Cs Section 12.9) which may be retained by FEI/FEVI, although this is very infrequent.

Both the timing and number of attachments in any main extension project contain the most uncertainty. In most instances, the number of homes that a developer plans to build will be significantly impacted by a multitude of external factors such as the economy, housing market, interest rates, labour market, cost of materials and planning and development issues. For example, a developer, due to economic conditions, may reduce the number of homes to be built after the completion of the main extension. These same issues are present for other utilities such as water, and electricity, and although the Companies work closely with the developer in determining forecasts, the number of unknown factors involved result in forecasted attachments that will inevitably be variable from the actuals on a yearly basis. However, over the life of the asset, the Company expects that the forecast attachments will materialize.

5.3 Mains Cost

There are two key components which contribute to the costs portion of the Main Extension Test, the mains cost and service cost. The mains cost accounts for the majority of the total cost of a project and would include a full scope of expenses such as planning, materials and labour. The service line costs generally contribute much less to a project's final cost, but their impact would increase in projects such as a residential subdivision where a developer plans to install a large number of homes. Both the mains and service line costs are discussed below.

As will be seen in the data tables in the 2012 MX Report, the MX Test element that has the least amount of variability is the cost of the main extension. In the past, the original forecast mechanism for determining main extension costs was a single Geo-Price based approach where the cost per meter was essentially derived from the geographic location of the main and the environmental characteristics of that area. However, the Companies still saw variability between the forecast and the actuals in those projects that included special characteristics such as a bridge or water crossing, larger size main, higher pressure requirements. To better capture the cost differences associated with these features, the Companies introduced in 2010 a pilot set of Manual Estimate criteria which were fully implemented in 2011 and are now used as an alternative to the Geo-Price method. These criteria are provided in the Geo Codes and Manual Estimates tables of this Report. For the small percentage of main extensions (approximately 10 percent) where manual estimating is determined to be appropriate, the person responsible for developing the cost estimate of the project (the "Planner") uses information contained in the construction services contract with the Companies' service provider. In other words, the Planner uses the same criteria for cost projections as those actually performing the construction of these projects. As a result, the historic and current variances between the forecasted and actual main costs have been relatively minor and are reflected in the aggregate sample results throughout this MX Report.

5.4 Service Cost

The Companies have also employed the Geo-Price based approach when estimating the cost of a new service line. However, the service cost estimates will generally have a greater level of variance than the mains cost. For example, each attachment or "lot" in new subdivision would have its own unique set of characteristics, such as ground cover, soil type, lot size, and service line distance. As such, the variance between forecast and actual service line costs can be expected to be relatively high.

As described above in Section 3.3, the introduction of a Manual Estimate approach used in conjunction with Geo-Prices has helped to minimize the variances between forecasted and actual service line costs. Although the variances contained in this Report are reasonable, due to unforeseen circumstances such as rocky ground cover, conflicts with foreign utilities and changes made by the developer, there will always be a variance between the forecast and actual service line costs.

6 2012 MAIN EXTENSIONS

The following section summarizes the aggregate and top 5 results for the 2012 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2012 gas year (November 01, 2011 to October 31, 2012).
- The first year of actual results for this section will appear in the 2013 Main Extension Report.
- The tables included in this section contain a comparison of forecasted and actual mains costs only.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables below is used to indicate a forecast year.
- The 2012 main extension data tables as well as future report tables reflect the expanded rate class breakdown as discussed in Section 1.

6.1 2012 FEI Random Sample Results

The tables below summarize the sample aggregate 2012 main extension results for FEI.

Table 9: 2012 FEI Aggregate Main Extensions Costs

2012 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 585,584	$ 644,832	10%
	Service lines and meters	$ 246,400	$ -	-100%
	Year 1 Total	$ 831,984	$ 644,832	-22%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 106,805	$ -	-100%
	Year 2 Total	$ 106,805	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 99,310	$ -	-100%
	Year 3 Total	$ 99,310	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 76,824	$ -	-100%
	Year 4 Total	$ 76,824	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 51,529	$ -	-100%
	Year 5 Total	$ 51,529	$ -	-100%
Years 1-5 Total		**$1,166,451**	**$644,832**	**-45%**

Table 10: 2012 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2012 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**263**	**263**	**0%**	**101,576**	**101,576**	**0%**	**386**	**386**	**0%**
Rate 1	*173*	*173*	*0%*	*20,640*	*20,640*	*0%*	*119*	*119*	*0%*
Rate 2	*88*	*88*	*0%*	*41,307*	*41,307*	*0%*	*469*	*469*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 2	**377**	**377**	**0%**	**111,841**	**111,841**	**0%**	**297**	**297**	**0%**
Rate 1	*270*	*270*	*0%*	*29,246*	*29,246*	*0%*	*108*	*108*	*0%*
Rate 2	*105*	*105*	*0%*	*42,966*	*42,966*	*0%*	*409*	*409*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 3	**483**	**483**	**0%**	**122,484**	**122,484**	**0%**	**254**	**254**	**0%**
Rate 1	*373*	*373*	*0%*	*37,536*	*37,536*	*0%*	*101*	*101*	*0%*
Rate 2	*108*	*108*	*0%*	*45,319*	*45,319*	*0%*	*420*	*420*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 4	**565**	**565**	**0%**	**129,157**	**129,157**	**0%**	**229**	**229**	**0%**
Rate 1	*452*	*452*	*0%*	*41,856*	*41,856*	*0%*	*93*	*93*	*0%*
Rate 2	*111*	*111*	*0%*	*47,672*	*47,672*	*0%*	*429*	*429*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 5	**620**	**620**	**0%**	**135,819**	**135,819**	**0%**	**219**	**219**	**0%**
Rate 1	*496*	*496*	*0%*	*45,452*	*45,452*	*0%*	*92*	*92*	*0%*
Rate 2	*122*	*122*	*0%*	*50,738*	*50,738*	*0%*	*416*	*416*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Years 1-5 Total	**620**	**620**	**0%**	**600,877**	**600,877**	**0%**	**219**	**219**	**0%**

Table 11: 2012 FEI Aggregate Main Extensions Profitability Index

2012 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	2.41	2.37	-2%
Years 1-5 Total	**2.41**	**2.37**	**-2%**

Notes:

- The actual main extension costs compared to forecast costs are $60,000 higher for FEI representing a 10 percent cost variance. This variance is reasonable in that it is as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.
- 11 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

1 ## 6.2 2012 FEVI Random Sample Results

2 The tables below summarize the sample aggregate 2012 main extension results for FEVI.

3 **Table 12: 2012 FEVI Aggregate Main Extensions Costs**

4

2012 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 367,763	$ 350,279	-5%
	Service lines and meters	$ 109,251	$ -	-100%
	Year 1 Total	$ 477,014	$ 350,279	-27%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 38,486	$ -	-100%
	Year 2 Total	$ 38,486	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 28,554	$ -	-100%
	Year 3 Total	$ 28,554	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 4 Total	$ 12,415	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 5 Total	$ 12,415	$ -	-100%
Years 1-5 Total		**$568,885**	**$350,279**	**-38%**

Table 13: 2012 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2012 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**88**	**88**	**0%**	**9,725**	**9,725**	**0%**	**111**	**111**	**0%**
Rate 1	*78*	*78*	*0%*	*4,210*	*4,210*	*0%*	*54*	*54*	*0%*
Rate 2	*5*	*5*	*0%*	*710*	*710*	*0%*	*142*	*142*	*0%*
Rate 3	*5*	*5*	*0%*	*4,805*	*4,805*	*0%*	*961*	*961*	*0%*
Year 2	**119**	**119**	**0%**	**11,362**	**11,362**	**0%**	**95**	**95**	**0%**
Rate 1	*109*	*109*	*0%*	*5,847*	*5,847*	*0%*	*54*	*54*	*0%*
Rate 2	*5*	*5*	*0%*	*710*	*710*	*0%*	*142*	*142*	*0%*
Rate 3	*5*	*5*	*0%*	*4,805*	*4,805*	*0%*	*961*	*961*	*0%*
Year 3	**142**	**142**	**0%**	**13,010**	**13,010**	**0%**	**92**	**92**	**0%**
Rate 1	*131*	*131*	*0%*	*7,295*	*7,295*	*0%*	*56*	*56*	*0%*
Rate 2	*6*	*6*	*0%*	*910*	*910*	*0%*	*152*	*152*	*0%*
Rate 3	*5*	*5*	*0%*	*4,805*	*4,805*	*0%*	*961*	*961*	*0%*
Year 4	**152**	**152**	**0%**	**13,475**	**13,475**	**0%**	**89**	**89**	**0%**
Rate 1	*141*	*141*	*0%*	*7,760*	*7,760*	*0%*	*55*	*55*	*0%*
Rate 2	*6*	*6*	*0%*	*910*	*910*	*0%*	*152*	*152*	*0%*
Rate 3	*5*	*5*	*0%*	*4,805*	*4,805*	*0%*	*961*	*961*	*0%*
Year 5	**162**	**162**	**0%**	**13,805**	**13,805**	**0%**	**85**	**85**	**0%**
Rate 1	*151*	*151*	*0%*	*8,090*	*8,090*	*0%*	*54*	*54*	*0%*
Rate 2	*6*	*6*	*0%*	*910*	*910*	*0%*	*152*	*152*	*0%*
Rate 3	*5*	*5*	*0%*	*4,805*	*4,805*	*0%*	*961*	*961*	*0%*
Years 1-5 Total	**162**	**162**	**0%**	**61,377**	**61,377**	**0%**	**85**	**85**	**0%**

Table 14: 2012 FEI Aggregate Main Extensions Profitability Index

2012 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.39	1.43	3%
Years 1-5 Total	**1.39**	**1.43**	**3%**

Notes:

- The actual main extension costs compared to forecast costs are $18,000 lower for FEVI representing a 3 percent cost variance. This variance is reasonable in that it is as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.
- 10 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

6.3 2012 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 15 & 16	Table 17 & 18	Table 19 & 20	Table 21 & 22	Table 23 & 24	Table 25
201 Street	Pandosy Street	E. Kent Avenue	Cordova Way	Fremont Street	Top 5 PI Results

Table 15: 2012 FEI Top 5 – 201st Street Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003835	201 Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 42,131	$ 73,935	75%
	Service lines and meters	$ 937	$ -	-100%
	Year 1 Total	$ 43,068	$ 73,935	72%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 937	$ -	-100%
	Year 2 Total	$ 937	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$44,005	$73,935	68%

Notes:

- Due to a damaged main, the original tie in location for this project had to be moved resulting in additional labour and material charges.
- The running line for this main also ended up being in direct conflict with Telus services which had been moved after the initial planning of the project.
- Several conflicts with existing water lines were encountered resulting in additional labour charges.

Table 16: 2012 FEI Top 5 – 201st Street Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550003835 201 Street	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**1**	**0%**	**1,998**	**1,998**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*1,998*	*1,998*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**2**	**2**	**0%**	**17,982**	**17,982**	**0%**	**1,998**	**1,998**	**0%**	

Table 17: 2012 FEI Top 5 – Pandosy Street Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550004072	Pandosy Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 60,000	$ 54,841	-9%
	Service lines and meters	$ 937	$ -	-100%
	Year 1 Total	$ 60,937	$ 54,841	-10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$60,937**	**$54,841**	**-10%**

Table 18: 2012 FEI Top 5 – Pandosy Street Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550004072 Pandosy Street	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 2	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 3	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 4	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 5	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Years 1-5 Total	**1**	**1**	**0%**	**184,320**	**184,320**	**0%**	**36,864**	**36,864**	**0%**	

Table 19: 2012 FEI Top 5 – E. Kent Avenue Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550005506	E Kent Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 66,965	$ 77,867	16%
	Service lines and meters	$ 14,990	$ -	-100%
	Year 1 Total	$ 81,955	$ 77,867	-5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$81,955	$77,867	-5%

Table 20: 2012 FEI Top 5 – E. Kent Avenue Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550005506 E Kent Avenue	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**16**	**16**	**0%**	**24,320**	**24,320**	**0%**	**304**	**304**	**0%**	

Table 21: 2012 FEI Top 5 – Cordova Way Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550005581	Cordova Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 140,283	$ 102,168	-27%
	Service lines and meters	$ 2,811	$ -	-100%
	Year 1 Total	$ 143,094	$ 102,168	-29%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 2 Total	$ 2,811	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 3 Total	$ 2,811	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 937	$ -	-100%
	Year 4 Total	$ 937	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 1,874	$ -	-100%
	Year 5 Total	$ 1,874	$ -	-100%
Years 1-5 Total		$151,526	$102,168	-33%

Table 22: 2012 FEI Top 5 – Cordova Way Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550005581 Cordova Way	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**3**	**3**	**0%**	**1,050**	**1,050**	**0%**	**350**	**350**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*3*	*3*	*0%*	*1,050*	*1,050*	*0%*	*350*	*350*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**6**	**6**	**0%**	**2,182**	**2,182**	**0%**	**364**	**364**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*6*	*6*	*0%*	*2,182*	*2,182*	*0%*	*364*	*364*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**9**	**9**	**0%**	**3,282**	**3,282**	**0%**	**365**	**365**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*9*	*9*	*0%*	*3,282*	*3,282*	*0%*	*365*	*365*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**10**	**10**	**0%**	**3,682**	**3,682**	**0%**	**368**	**368**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*10*	*10*	*0%*	*3,682*	*3,682*	*0%*	*368*	*368*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**12**	**12**	**0%**	**4,482**	**4,482**	**0%**	**374**	**374**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*12*	*12*	*0%*	*4,482*	*4,482*	*0%*	*374*	*374*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**12**	**12**	**0%**	**14,678**	**14,678**	**0%**	**374**	**374**	**0%**	

Table 23: 2012 FEI Top 5 – Fremont Street Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550005794	Fremont Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 94,046	$ 87,235	-7%
	Service lines and meters	$ 1,874	$ -	-100%
	Year 1 Total	$ 95,920	$ 87,235	-9%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 937	$ -	-100%
	Year 2 Total	$ 937	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 3 Total	$ 2,811	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 4 Total	$ 2,811	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 5 Total	$ 2,811	$ -	-100%
Years 1-5 Total		$105,288	$87,235	-17%

Table 24: 2012 FEI Top 5 – Fremont Street Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550005794 Fremont Street	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**2**	**2**	**0%**	**1,421**	**1,421**	**0%**	**711**	**711**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*1,421*	*1,421*	*0%*	*711*	*711*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**3**	**3**	**0%**	**2,078**	**2,078**	**0%**	**693**	**693**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*3*	*3*	*0%*	*2,078*	*2,078*	*0%*	*693*	*693*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**6**	**6**	**0%**	**4,431**	**4,431**	**0%**	**739**	**739**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*6*	*6*	*0%*	*4,431*	*4,431*	*0%*	*739*	*739*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**9**	**9**	**0%**	**6,784**	**6,784**	**0%**	**754**	**754**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*9*	*9*	*0%*	*6,784*	*6,784*	*0%*	*754*	*754*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**12**	**12**	**0%**	**9,137**	**9,137**	**0%**	**761**	**761**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*12*	*12*	*0%*	*9,137*	*9,137*	*0%*	*761*	*761*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**12**	**12**	**0%**	**23,851**	**23,851**	**0%**	**761**	**761**	**0%**	

Table 25: 2012 FEI Top 5 Main Extensions Profitability Index

2012 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
201 Street	1.48	0.89	-40%
Pandosy Street	9.20	10.04	9%
E Kent Avenue	1.55	1.35	-13%
Cordova Way	0.80	0.71	-11%
Fremont Street	0.98	1.15	17%
Years 1-5 Total	**1.48**	**0.89**	**-40%**

6.4 2012 FEVI Top 5 Results

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 26 & 27	Table 28 & 29	Table 30 & 31	Table 32 & 33	Table 34 & 35	Table 36
Arbot Road	Small Road	Rutherford Road	Bowen Road	Delamere Road	Top 5 PI Results

Table 26: 2012 FEVI Top 5 – Arbot Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEVI 5550004441	Arbot Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 108,738	$ 128,245	18%
	Service lines and meters	$ 3,724	$ -	-100%
	Year 1 Total	$ 112,462	$ 128,245	14%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 6,207	$ -	-100%
	Year 2 Total	$ 6,207	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 6,207	$ -	-100%
	Year 3 Total	$ 6,207	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 8,690	$ -	-100%
	Year 4 Total	$ 8,690	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 6,207	$ -	-100%
	Year 5 Total	$ 6,207	$ -	-100%
Years 1-5 Total		$139,775	$128,245	-8%

Table 27: 2012 FEVI Top 5 – Arbot Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			Ramp-Up Factor
FEVI 5550004441 Arbot Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	3	3	0%	150	150	0%	50	50	0%	
Rate 1	3	3	0%	150	150	0%	50	50	0%	
Rate 2	0	0		0	0					
Rate 3	0	0		0	0					
Year 2	8	8	0%	400	400	0%	50	50	0%	
Rate 1	8	8	0%	400	400	0%	50	50	0%	
Rate 2	0	0		0	0					
Rate 3	0	0		0	0					
Year 3	13	13	0%	650	650	0%	50	50	0%	
Rate 1	13	13	0%	650	650	0%	50	50	0%	
Rate 2	0	0		0	0					
Rate 3	0	0		0	0					
Year 4	20	20	0%	1,000	1,000	0%	50	50	0%	
Rate 1	20	20	0%	1,000	1,000	0%	50	50	0%	
Rate 2	0	0		0	0					
Rate 3	0	0		0	0					
Year 5	25	25	0%	1,250	1,250	0%	50	50	0%	
Rate 1	25	25	0%	1,250	1,250	0%	50	50	0%	
Rate 2	0	0		0	0					
Rate 3	0	0		0	0					
Years 1-5 Total	25	25	0%	3,450	3,450	0%	50	50	0%	

Table 28: 2012 FEVI Top 5 – Small Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004572	Small Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 23,350	$ 29,972	28%
	Service lines and meters	$ 1,241	$ -	-100%
	Year 1 Total	$ 24,591	$ 29,972	22%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 1,241	$ -	-100%
	Year 3 Total	$ 1,241	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$25,833	$29,972	16%

Notes:

- A directional drill underneath a Highway and extra depth requirements resulted in driving actual costs higher than forecast.

Table 29: 2012 FEVI Top 5 – Small Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550004572 Small Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**1**	**0%**	**288**	**288**	**0%**	**288**	**288**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*288*	*288*	*0%*	*288*	*288*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**1**	**1**	**0%**	**288**	**288**	**0%**	**288**	**288**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*288*	*288*	*0%*	*288*	*288*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**2**	**2**	**0%**	**488**	**488**	**0%**	**244**	**244**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*488*	*0%*	*244*	*244*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**2**	**2**	**0%**	**488**	**488**	**0%**	**244**	**244**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*488*	*0%*	*244*	*244*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**2**	**2**	**0%**	**488**	**488**	**0%**	**244**	**244**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*488*	*0%*	*244*	*244*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**2**	**2**	**0%**	**2,040**	**2,040**	**0%**	**244**	**244**	**0%**	

1 **Table 30: 2012 FEVI Top 5 – Rutherford Road Costs**

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550005404	Rutherford Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 52,525	$ 62,901	20%
	Service lines and meters	$ 12,415	$ -	-100%
	Year 1 Total	$ 64,940	$ 62,901	-3%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ -	-100%
	Year 2 Total	$ 14,898	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 9,932	$ -	-100%
	Year 3 Total	$ 9,932	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 9,932	$ -	-100%
	Year 4 Total	$ 9,932	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 5 Total	$ 12,415	$ -	-100%
Years 1-5 Total		$112,117	$62,901	-44%

2

3 **Table 31: 2012 FEVI Top 5 – Rutherford Road Attachments, Consumption and Use per Customer**

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550005404 Rutherford Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**10**	**10**	**0%**	**396**	**396**	**0%**	**40**	**40**	**0%**	
Rate 1	*10*	*10*	*0%*	*396*	*396*	*0%*	*40*	*40*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**22**	**22**	**0%**	**1,004**	**1,004**	**0%**	**46**	**46**	**0%**	
Rate 1	*22*	*22*	*0%*	*1,004*	*1,004*	*0%*	*46*	*46*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**30**	**30**	**0%**	**1,321**	**1,321**	**0%**	**44**	**44**	**0%**	
Rate 1	*30*	*30*	*0%*	*1,321*	*1,321*	*0%*	*44*	*44*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**38**	**38**	**0%**	**1,638**	**1,638**	**0%**	**43**	**43**	**0%**	
Rate 1	*38*	*38*	*0%*	*1,638*	*1,638*	*0%*	*43*	*43*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**48**	**48**	**0%**	**2,034**	**2,034**	**0%**	**42**	**42**	**0%**	
Rate 1	*48*	*48*	*0%*	*2,034*	*2,034*	*0%*	*42*	*42*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**48**	**48**	**0%**	**6,393**	**6,393**	**0%**	**42**	**42**	**0%**	

4

Table 32: 2012 FEVI Top 5 – Bowen Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550005574	Bowen Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 31,520	$ 31,041	-2%
	Service lines and meters	$ 17,381	$ -	-100%
	Year 1 Total	$ 48,901	$ 31,041	-37%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 2 Total	$ 12,415	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$61,316	$31,041	-49%

Table 33: 2012 FEVI Top 5 – Bowen Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550005574 Bowen Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**14**	**14**	**0%**	**420**	**420**	**0%**	**30**	**30**	**0%**	
Rate 1	*14*	*14*	*0%*	*420*	*420*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**24**	**24**	**0%**	**3,300**	**3,300**	**0%**	**30**	**30**	**0%**	

Table 34: 2012 FEVI Top 5 – Delamere Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550006162	Delamere Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 13,558	$ 33,830	150%
	Service lines and meters	$ 3,724	$ -	-100%
	Year 1 Total	$ 17,282	$ 33,830	96%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$17,282	$33,830	96%

Notes:

- The running line for this main was in conflict with asphalt for 143 meters. As a result, significant pavement costs were incurred that were not captured by the original geo-priced forecast.

Table 35: 2012 FEVI Top 5 – Delamere Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550006162 Delamere Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**3**	**3**	**0%**	**190**	**190**	**0%**	**63**	**63**	**0%**	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**3**	**3**	**0%**	**190**	**190**	**0%**	**63**	**63**	**0%**	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**3**	**3**	**0%**	**190**	**190**	**0%**	**63**	**63**	**0%**	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**3**	**3**	**0%**	**190**	**190**	**0%**	**63**	**63**	**0%**	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**3**	**3**	**0%**	**190**	**190**	**0%**	**63**	**63**	**0%**	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**3**	**3**	**0%**	**950**	**950**	**0%**	**63**	**63**	**0%**	

Table 36: 2012 FEVI Top 5 Main Extensions Profitability Index

2012 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Arbot Road	0.80	0.39	-51%
Small Road	1.31	1.06	-19%
Rutherford Road	0.92	0.85	-8%
Bowen Road	0.80	0.81	1%
Delamere Road	0.80	0.21	-73%
Years 1-5 Total	**0.80**	**0.39**	**-51%**

7 2011 MAIN EXTENSIONS

The following section summarizes the aggregate and top 5 results for the 2011 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2011 gas year (November 01, 2010 to October 31, 2011).
- The actual results in this section are from November 01, 2010 to October 31, 2011.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 1.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables below is used to indicate a forecast year.

7.1 2011 FEI Random Sample Results

The tables below summarize the sample aggregate 2011 main extension results for FEI.

Table 37: 2011 FEI Aggregate Main Extensions Costs

2011 SAMPLE MAIN EXTENSIONS - COSTS				
		Cost of Installation ($)		
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 634,248	$ 727,525	15%
	Service lines and meters	$ 415,268	$ 644,910	55%
	Year 1 Total	$ 1,049,516	$ 1,372,435	31%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 165,872	$ -	-100%
	Year 2 Total	$ 165,872	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 109,405	$ -	-100%
	Year 3 Total	$ 109,405	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 59,996	$ -	-100%
	Year 4 Total	$ 59,996	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 90,583	$ -	-100%
	Year 5 Total	$ 90,583	$ -	-100%
Years 1-5 Total		**$1,475,371**	**$1,372,435**	**-7%**

Table 38: 2011 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2011 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	353	415	18%	45,968	43,369	-6%	130	105	-20%
Year 2	494	556	13%	59,622	57,023	-4%	121	103	-15%
Year 3	587	649	11%	68,784	66,185	-4%	117	102	-13%
Year 4	638	700	10%	73,054	70,455	-4%	115	101	-12%
Year 5	715	777	9%	87,574	84,975	-3%	122	109	-11%
Years 1-5 Total	**715**	**777**	**9%**	**335,002**	**322,009**	**-4%**	**122**	**109**	**-11%**

Table 39: 2011 FEI Aggregate Main Extensions Profitability Index

2011 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.39	1.03	-26%
Years 1-5 Total	**1.39**	**1.03**	**-26%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[12].
- The variance between the year 1 forecast and year 1 actual costs is attributable to a combination of variance in costs and attachments.
- 7 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

7.2 2011 FEVI Random Sample Results

The tables below summarize the sample aggregate 2011 main extension results for FEVI.

[12] FEI & FEVI Main Extension Report for 2011 Year End, submitted to the Commission July 31, 2012.

Table 40: 2011 FEVI Aggregate Main Extensions Costs

2011 SAMPLE MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 513,670	$ 557,216	8%
	Service lines and meters	$ 196,013	$ 188,032	-4%
	Year 1 Total	$ 709,683	$ 745,248	5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 93,849	$ -	-100%
	Year 2 Total	$ 93,849	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 41,579	$ -	-100%
	Year 3 Total	$ 41,579	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 7,128	$ -	-100%
	Year 4 Total	$ 7,128	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 7,128	$ -	-100%
	Year 5 Total	$ 7,128	$ -	-100%
Years 1-5 Total		**$859,365**	**$745,248**	**-13%**

Table 41: 2011 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2011 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEVI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	165	128	-22%	15,038	21,673	44%	91	169	86%
Year 2	244	207	-15%	18,246	24,881	36%	75	120	61%
Year 3	279	242	-13%	19,495	26,130	34%	70	108	55%
Year 4	285	248	-13%	19,709	26,344	34%	69	106	54%
Year 5	291	254	-13%	19,958	26,593	33%	69	105	53%
Years 1-5 Total	**291**	**254**	**-13%**	**92,446**	**125,620**	**36%**	**69**	**105**	**53%**

Table 42: 2011 FEVI Aggregate Main Extensions Profitability Index

2011 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	**Original Years 1-5 Forecast**	**Re-calculated PI with actual data**	**Variance %**
Year 1 Year 2 Year 3 Year 4 Year 5	1.33	1.68	26%
Years 1-5 Total	**1.33**	**1.68**	**26%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[13].
- The variance between the year 1 forecast and year 1 actual costs is attributable to a combination of variance in costs and attachments.
- 7 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

7.3 2011 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 43 & 44	Table 45 & 46	Table 47 & 48	Table 49 & 50	Table 51 & 52	Table 53
96 Avenue	Harper Road	Townshipline Road	Sammet Road	1st Avenue	Top 5 PI Results

[13] FEI & FEVI Main Extension Report for 2011 Year End, submitted to the Commission July 31, 2012.

Table 43: 2011 FEI Top 5 – 96th Avenue Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003882	96 Ave	Original Forecast	Actual	Variance %
Year 1	Mains	$ 69,593	$ 74,954	8%
	Service lines and meters	$ 1,176	$ 3,108	164%
	Year 1 Total	$ 70,769	$ 78,062	10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 1,176	$ -	-100%
	Year 2 Total	$ 1,176	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$71,946**	**$78,062**	**9%**

Table 44: 2011 FEI Top 5 – 96th Avenue Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
96 Ave 5550003882	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	1	2	100%	11,271	10,143	-10%	11,271	5,071	-55%	
Year 2	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	0%
Year 3	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	
Year 4	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	
Year 5	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	
Years 1-5 Total	**2**	**3**	**50%**	**101,087**	**95,446**	**-6%**	**11,227**	**7,109**	**-37%**	

1 **Table 45: 2011 FEI Top 5 – Harper Road Costs**

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550002684	Harper Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 98,437	$ 73,832	-25%
	Service lines and meters	$ 27,057	$ 82,362	204%
	Year 1 Total	$ 125,494	$ 156,194	24%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 2 Total	$ 27,057	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 3 Total	$ 27,057	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 4 Total	$ 27,057	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 5 Total	$ 27,057	$ -	-100%
Years 1-5 Total		**$233,723**	**$156,194**	**-33%**

2

3

4 **Table 46: 2011 FEI Top 5 – Harper Road Attachments, Consumption and Use per Customer**

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Harper Rd 5550002684	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	23	53	130%	2,292	3,365	47%	100	63	-36%	
Year 2	46	76	65%	4,584	5,657	23%	100	74	-25%	
Year 3	69	99	43%	6,876	7,949	16%	100	80	-19%	0%
Year 4	92	122	33%	9,168	10,241	12%	100	84	-16%	
Year 5	115	145	26%	11,460	12,533	9%	100	86	-13%	
Years 1-5 Total	**115**	**145**	**26%**	**34,380**	**39,743**	**16%**	**100**	**86**	**-13%**	

5

6

Table 47: 2011 FEI Top 5 – Townshipline Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550004429	Townshipline Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 27,222	$ 48,855	79%
	Service lines and meters	$ 1,176	$ 1,554	32%
	Year 1 Total	$ 28,399	$ 50,409	78%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$28,399**	**$50,409**	**78%**

Table 48: 2011 FEI Top 5 – Townshipline Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Townshipline Road 5550004429	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	1	1	0%	576	11,201	1845%	576	11,201	1845%	
Year 2	1	1	0%	576	11,201	1845%	576	11,201	1845%	
Year 3	1	1	0%	576	11,201	1845%	576	11,201	1845%	0%
Year 4	1	1	0%	576	11,201	1845%	576	11,201	1845%	
Year 5	1	1	0%	576	11,201	1845%	576	11,201	1845%	
Years 1-5 Total	**1**	**1**	**0%**	**2,880**	**56,005**	**1845%**	**576**	**11,201**	**1845%**	

Notes:

- Customer is classified as a Rate 3 (Greenhouse) with consumption levels reflecting an expansion of original project requirements.

Table 49: 2011 FEI Top 5 – Sammet Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003356	Sammet Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 59,469	$ 23,830	-60%
	Service lines and meters	$ 2,353	$ 3,108	32%
	Year 1 Total	$ 61,822	$ 26,938	-56%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$61,822**	**$26,938**	**-56%**

Table 50: 2011 FEI Top 5 – Sammet Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Sammet Rd 5550003356	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	2	2	0%	610	1,192	95%	305	596	95%	
Year 2	2	2	0%	610	1,192	95%	305	596	95%	
Year 3	2	2	0%	610	1,192	95%	305	596	95%	0%
Year 4	2	2	0%	610	1,192	95%	305	596	95%	
Year 5	2	2	0%	610	1,192	95%	305	596	95%	
Years 1-5 Total	**2**	**2**	**0%**	**3,050**	**5,961**	**95%**	**305**	**596**	**95%**	

Notes:

- The actual costs for this project are reduced by a CIAC of approximately $57,000.
- There were cost over-runs due to traffic management (on highway) and a difficult running line to avoid a newly paved secondary highway. These additional costs are reflected in the actual PI result found in Table 53.

Table 51: 2011 FEI Top 5 – 1st Avenue Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003968	1st Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 38,704	$ 14,623	-62%
	Service lines and meters	$ 2,353	$ 3,108	32%
	Year 1 Total	$ 41,057	$ 17,731	-57%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$41,057**	**$17,731**	**-57%**

Table 52: 2011 FEI Top 5 – 1st Avenue Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
1st Avenue 5550003968	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	2	2	0%	245	219	-11%	123	110	-11%	
Year 2	2	2	0%	245	219	-11%	123	110	-11%	0%
Year 3	2	2	0%	245	219	-11%	123	110	-11%	
Year 4	2	2	0%	245	219	-11%	123	110	-11%	
Year 5	2	2	0%	245	219	-11%	123	110	-11%	
Years 1-5 Total	**2**	**2**	**0%**	**1,225**	**1,095**	**-11%**	**123**	**110**	**-11%**	

Notes:

- The actual costs for this project are reduced by a CIAC of approximately $42,000.
- There were cost over-runs due to impediments around a directional drill underneath three existing CP railway lines. These additional costs are reflected in the actual PI result found in Table 53.

Table 53: 2011 FEI Top 5 Main Extensions Profitability Index

2011 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
96 Ave	4.18	3.54	-15%
Harper Rd	1.15	0.97	-15%
Townshipline Road	0.83	3.16	281%
Sammet Rd	0.80	0.81	1%
1st Avenue	0.80	0.22	-72%
Years 1-5 Total	**1.55**	**1.74**	**12%**

7.1 2011 FEVI Top 5 Results

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 54 & 55	Table 56 & 57	Table 58 & 59	Table 60 & 61	Table 62 & 63	Table 64
Englewood Road	Mountain Heights Road	Sooke Road	Veteran's Memorial Parkway	Latoria Road	Top 5 PI Results

Table 54: 2011 FEVI Top 5 – Englewood Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004644	Englewood Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 53,758	$ 101,509	89%
	Service lines and meters	$ 19,007	$ 27,911	47%
	Year 1 Total	$ 72,765	$ 129,420	78%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 10,692	$ -	-100%
	Year 2 Total	$ 10,692	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,316	$ -	-100%
	Year 3 Total	$ 8,316	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 4,752	$ -	-100%
	Year 4 Total	$ 4,752	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,752	$ -	-100%
	Year 5 Total	$ 4,752	$ -	-100%
Years 1-5 Total		**$101,276**	**$129,420**	**28%**

Table 55: 2011 FEVI Top 5 – Englewood Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Englewood Rd 5550004644	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	16	19	19%	634	150	-76%	40	8	-80%	
Year 2	25	28	12%	991	507	-49%	40	18	-54%	
Year 3	32	35	9%	1,269	785	-38%	40	22	-43%	80%
Year 4	36	39	8%	1,428	944	-34%	40	24	-39%	
Year 5	40	43	8%	1,587	1,103	-31%	40	26	-35%	
Years 1-5 Total	**40**	**43**	**8%**	**5,909**	**3,487**	**-41%**	**40**	**26**	**-35%**	

Notes:

- Construction costs are higher due to a difficult job site, including additional costs for paving.
- The gas load estimate included installation of a hot water tank, fireplace and BBQ. The consumption projection anticipated a higher uptake on hot water tanks per home than actual. The market showed that entry level customers were seeking a lowest cost option.
- Several lots that have been developed have not been sold and exhibit consumption reflective of appliance testing and construction heat only.

Table 56: 2011 FEVI Top 5 – Mountain Heights Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550003319	Mountain Heights Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 88,037	$ 99,102	13%
	Service lines and meters	$ 47,518	$ 10,283	-78%
	Year 1 Total	$ 135,556	$ 109,385	-19%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 35,639	$ -	-100%
	Year 2 Total	$ 35,639	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,759	$ -	-100%
	Year 3 Total	$ 23,759	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$194,953**	**$109,385**	**-44%**

Table 57: 2011 FEVI Top 5 – Mountain Heights Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Mountain Heights Rd 5550003319	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	40	7	-83%	3,370	63	-98%	84	9	-89%	
Year 2	70	37	-47%	5,898	2,591	-56%	84	70	-17%	
Year 3	90	57	-37%	7,583	4,276	-44%	84	75	-11%	0%
Year 4	90	57	-37%	7,583	4,276	-44%	84	75	-11%	
Year 5	90	57	-37%	7,583	4,276	-44%	84	75	-11%	
Years 1-5 Total	**90**	**57**	**-37%**	**32,017**	**15,480**	**-52%**	**84**	**75**	**-11%**	

Notes:

- The developer of this subdivision sold individual lots to builders with the majority of lots in the development still vacant or at the early stages of construction.
- Those lots that have been developed have not been sold and exhibit consumption reflective of appliance testing and construction heat only.
- The Companies are currently tracking building permits and will engage builders in discussions regarding energy solutions.

Table 58: 2011 FEVI Top 5 – Sooke Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004292	Sooke Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 136,725	$ 68,387	-50%
	Service lines and meters	$ 59,398	$ -	-100%
	Year 1 Total	$ 196,123	$ 68,387	-65%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 59,398	$ -	-100%
	Year 2 Total	$ 59,398	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$255,521**	**$68,387**	**-73%**

Table 59: 2011 FEVI Top 5 – Sooke Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Sooke Road 5550004292	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	50	0	-100%	2,174	0	-100%	43			
Year 2	100	50	-50%	4,593	2,419	-47%	46	48	5%	0%
Year 3	100	50	-50%	4,593	2,419	-47%	46	48	5%	
Year 4	100	50	-50%	4,593	2,419	-47%	46	48	5%	
Year 5	100	50	-50%	4,593	2,419	-47%	46	48	5%	
Years 1-5 Total	**100**	**50**	**-50%**	**20,546**	**9,676**	**-53%**	**46**	**48**	**5%**	

Notes:

- Several large vertical subdivision buildings that were originally part of the project costs and were put on hold due to construction complications have recently been completed. The associated attachments, approximately 40 to 60 to date, will appear in future MX Reports.

Table 60: 2011 FEVI Top 5 – Veterans Memorial Parkway Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI 5550002742	Veteran's Memorial Parkway	Cost of Installation ($) Original Forecast	Actual	Variance %
Year 1	Mains	$ 54,615	$ 68,023	25%
	Service lines and meters	$ 13,068	$ -	-100%
	Year 1 Total	$ 67,683	$ 68,023	1%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 11,880	$ -	-100%
	Year 2 Total	$ 11,880	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 13,068	$ -	-100%
	Year 3 Total	$ 13,068	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 13,068	$ -	-100%
	Year 4 Total	$ 13,068	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 1,188	$ -	-100%
	Year 5 Total	$ 1,188	$ -	-100%
Years 1-5 Total		**$106,885**	**$68,023**	**-36%**

Table 61: 2011 FEVI Top 5 – Veterans Memorial Parkway Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Veteran's Memorial Parkway 5550002742	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	11	0	-100%	694	0	-100%	63			
Year 2	21	10	-52%	1,457	763	-48%	69	76	10%	
Year 3	32	21	-34%	1,964	1,270	-35%	61	60	-1%	45%
Year 4	43	32	-26%	2,471	1,777	-28%	57	56	-3%	
Year 5	44	33	-25%	2,536	1,842	-27%	58	56	-3%	
Years 1-5 Total	**44**	**33**	**-25%**	**9,122**	**5,652**	**-38%**	**58**	**56**	**-3%**	

Notes:

- Developer has taken a significant amount of time to register lots. Installation had to take place at an early stage of project as main alignment was projected to be under new asphalt. Lots have been registered for only 4 months and 2 lots have been sold to date. The developer expects sales to take off after provincial HST issue is resolved. The Companies are in contact with the developer to discuss marketing strategy.

Table 62: 2011 FEVI Top 5 – Latoria Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004579	Latoria Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 27,200	$ 55,572	104%
	Service lines and meters	$ 16,631	$ 20,566	24%
	Year 1 Total	$ 43,831	$ 76,138	74%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,316	$ -	-100%
	Year 2 Total	$ 8,316	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,316	$ -	-100%
	Year 3 Total	$ 8,316	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	

Table 63: 2011 FEVI Top 5 – Latoria Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Latoria Road 5550004579	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	14	14	0%	383	302	-21%	27	22	-21%	
Year 2	21	21	0%	575	494	-14%	27	24	-14%	
Year 3	28	28	0%	767	686	-11%	27	24	-11%	80%
Year 4	28	28	0%	767	686	-11%	27	24	-11%	
Year 5	28	28	0%	767	686	-11%	27	24	-11%	
Years 1-5 Total	**28**	**28**	**0%**	**3,259**	**2,854**	**-12%**	**27**	**24**	**-11%**	

Notes:

- Actual costs are higher due to a conflict with fire hydrants and a water main.

Table 64: 2011 FEVI Top 5 Main Extensions Profitability Index

2011 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Englewood Rd	0.95	0.36	-62%
Mountain Heights Rd	1.29	0.82	-36%
Sooke Road	1.45	2.09	44%
Veteran's Memorial Parkway	1.52	0.88	-42%
Latoria Road	0.87	0.44	-50%
Years 1-5 Total	**1.22**	**0.92**	**-25%**

8 2010 MAIN EXTENSIONS

The following section summarizes the attachment and consumption results for the 2010 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2010 gas year (November 01, 2009 to October 31, 2010).
- The actual results in this section are from November 01, 2009 to October 31, 2011.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 2.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables is used to indicate a forecast year.

8.1 2010 FEI Random Sample Results

The tables below summarize the sample aggregate 2010 main extension results for FEI.

Table 65: 2010 FEI Aggregate Main Extensions Costs

2010 SAMPLE MAIN EXTENSIONS - COSTS				
FEI	Cost of Installation ($)			
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 458,129	$ 453,092	-1%
	Service lines and meters	$ 234,992	$ 350,952	49%
	Year 1 Total	$ 693,121	$ 804,043	16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 93,463	$ 188,734	102%
	Year 2 Total	$ 93,463	$ 188,734	102%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 51,627	$ -	-100%
	Year 3 Total	$ 51,627	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 25,814	$ -	-100%
	Year 4 Total	$ 25,814	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 19,583	$ -	-100%
	Year 5 Total	$ 19,583	$ -	-100%
Years 1-5 Total		**$883,607**	**$992,778**	**12%**

Table 66: 2010 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2010 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	264	225	-15%	39,692	19,071	-52%	150	85	-44%
Year 2	369	346	-6%	50,019	29,288	-41%	136	85	-38%
Year 3	427	404	-5%	55,967	35,236	-37%	131	87	-33%
Year 4	456	433	-5%	58,932	38,201	-35%	129	88	-32%
Year 5	478	455	-5%	61,244	40,513	-34%	128	89	-31%
Years 1-5 Total	**478**	**455**	**-5%**	**265,854**	**162,308**	**-39%**	**128**	**89**	**-31%**

Table 67: 2010 FEI Aggregate Main Extensions Profitability Index

2010 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.69	0.90	-47%
Years 1-5 Total	**1.69**	**0.90**	**-47%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[14].
- The variance between the Year 1-2 forecast and Year 1-2 actual costs is attributable to a combination of variance in costs and attachments.
- 2 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

8.2 2010 FEVI Random Sample Results

The tables below summarize the sample aggregate 2010 main extension results for FEVI.

[14] Addendum to Main Extension Report and FortisBC Energy Inc. Vertical Subdivision Report for 2010 Year End, submitted to the Commission October 14, 2011.

Table 68: 2010 FEVI Aggregate Main Extensions Costs

2010 SAMPLE MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 467,152	$ 482,629	3%
	Service lines and meters	$ 267,481	$ 168,935	-37%
	Year 1 Total	$ 734,634	$ 651,564	-11%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 78,353	$ 117,520	50%
	Year 2 Total	$ 78,353	$ 117,520	50%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 9,006	$ -	-100%
	Year 3 Total	$ 9,006	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 7,205	$ -	-100%
	Year 4 Total	$ 7,205	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$829,198**	**$769,084**	**-7%**

Table 69: 2010 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2010 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEVI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	297	115	-61%	20,565	10,030	-51%	69	87	26%
Year 2	384	195	-49%	24,547	11,428	-53%	64	59	-8%
Year 3	394	205	-48%	24,899	11,780	-53%	63	57	-9%
Year 4	402	213	-47%	25,143	12,024	-52%	63	56	-10%
Year 5	402	213	-47%	25,143	12,024	-52%	63	56	-10%
Years 1-5 Total	**402**	**213**	**-47%**	**120,297**	**57,285**	**-52%**	**63**	**56**	**-10%**

Table 70: 2010 FEVI Aggregate Main Extensions Profitability Index

2010 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	**Original Years 1-5 Forecast**	**Re-calculated PI with actual data**	**Variance %**
Year 1 Year 2 Year 3 Year 4 Year 5	1.48	0.93	-37%
Years 1-5 Total	**1.48**	**0.93**	**-37%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed to the Commission[15].
- The variance between the Year 1-2 forecast and Year 1-2 actual costs is attributable to a combination of variance in costs and attachments.
- 7 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

8.3 2010 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 71 & 72	Table 73 & 74	Table 75 & 76	Table 77 & 78	Table 79 & 80	Table 81
Whiskey Jack Drive	Gislason Avenue	Progress Way	Highway 95A	Pinot Noir Drive	Top 5 PI Results

[15] Addendum to Main Extension Report and FortisBC Energy Inc. Vertical Subdivision Report for 2010 Year End, submitted to the Commission October 14, 2011.

Table 71: 2010 FEI Top 5 – Whiskey Jack Drive Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550002814	Whiskey Jack Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 110,429	$ 161,457	46%
	Service lines and meters	$ 26,704	$ 38,995	46%
	Year 1 Total	$ 137,132	$ 200,452	46%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ 20,277	14%
	Year 2 Total	$ 17,802	$ 20,277	14%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ -	-100%
	Year 3 Total	$ 4,451	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ -	-100%
	Year 4 Total	$ 4,451	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ -	-100%
	Year 5 Total	$ 4,451	$ -	-100%
Years 1-5 Total		**$168,286**	**$220,729**	**31%**

Table 72: 2010 FEI Top 5 – Whiskey Jack Drive Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Whiskey Jack Drive 5550002814	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	30	25	-17%	3,022	1,570	-48%	101	63	-38%	0%
Year 2	50	38	-24%	5,036	2,072	-59%	101	55	-46%	
Year 3	55	43	-22%	5,540	2,576	-54%	101	60	-41%	
Year 4	60	48	-20%	6,044	3,080	-49%	101	64	-36%	
Year 5	65	53	-18%	6,548	3,584	-45%	101	68	-33%	
Years 1-5 Total	**65**	**53**	**-18%**	**26,190**	**12,881**	**-51%**	**101**	**68**	**-33%**	

Notes:

- This project incurred extra costs for compaction, road repair and construction materials.
- The geo-priced cost forecasting was performed prior to the Companies implementing an enhancement for projects using large diameter pipe. As a result, the forecast costs were underestimated.

Table 73: 2010 FEI Top 5 – Gislason Avenue Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550001486	Gislason Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 144,616	$ 127,886	-12%
	Service lines and meters	$ 17,802	$ 113,864	540%
	Year 1 Total	$ 162,418	$ 241,750	49%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ 1,560	-91%
	Year 2 Total	$ 17,802	$ 1,560	-91%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ -	-100%
	Year 3 Total	$ 17,802	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ -	-100%
	Year 4 Total	$ 17,802	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ -	-100%
	Year 5 Total	$ 17,802	$ -	-100%
Years 1-5 Total		**$233,628**	**$243,310**	**4%**

Table 74: 2010 FEI Top 5 – Gislason Avenue Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Gislason Avenue 5550001486	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	20	73	265%	2,163	4,755	120%	108	65	-40%	0%
Year 2	40	74	85%	4,326	4,821	11%	108	65	-40%	
Year 3	60	94	57%	6,489	6,984	8%	108	74	-31%	
Year 4	80	114	43%	8,652	9,147	6%	108	80	-26%	
Year 5	100	134	34%	10,815	11,310	5%	108	84	-22%	
Years 1-5 Total	**100**	**134**	**34%**	**32,445**	**37,017**	**14%**	**108**	**84**	**-22%**	

Table 75: 2010 FEI Top 5 – Progress Way Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000039	Progress Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 118,642	$ 81,035	-32%
	Service lines and meters	$ 2,670	$ 1,560	-42%
	Year 1 Total	$ 121,313	$ 82,595	-32%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 10,681	$ -	-100%
	Year 2 Total	$ 10,681	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 3,560	$ -	-100%
	Year 3 Total	$ 3,560	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 890	$ -	-100%
	Year 4 Total	$ 890	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 3,560	$ -	-100%
	Year 5 Total	$ 3,560	$ -	-100%
Years 1-5 Total		**$140,005**	**$82,595**	**-41%**

Table 76: 2010 FEI Top 5 – Progress Way Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Progress Way 5550000039	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	3	1	-67%	1,912	200	-90%	637	200	-69%	0%
Year 2	15	1	-93%	4,629	200	-96%	309	200	-35%	
Year 3	19	5	-74%	7,178	2,749	-62%	378	550	46%	
Year 4	20	6	-70%	8,098	3,669	-55%	405	611	51%	
Year 5	24	10	-58%	11,543	7,114	-38%	481	711	48%	
Years 1-5 Total	**24**	**10**	**-58%**	**33,360**	**13,930**	**-58%**	**481**	**711**	**48%**	

Notes:

- The economic downturn is the main reason cited by the developer as to why there has been little attachment activity. However, all lots are now cleared with construction activity picking up.

1 **Table 77: 2010 FEI Top 5 – Highway 95A Costs**

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550004126	Highway 95A	Original Forecast	Actual	Variance %
Year 1	Mains	$ 63,050	$ 72,910	16%
	Service lines and meters	$ 13,352	$ 1,560	-88%
	Year 1 Total	$ 76,402	$ 74,470	-3%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,901	$ 4,679	-47%
	Year 2 Total	$ 8,901	$ 4,679	-47%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,901	$ -	-100%
	Year 3 Total	$ 8,901	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 8,901	$ -	-100%
	Year 4 Total	$ 8,901	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$103,105**	**$79,149**	**-23%**

2

3

4 **Table 78: 2010 FEI Top 5 – Highway 95A Attachments, Consumption and Use per Customer**

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Highway 95A 5550004126	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	15	1	-93%	1,511	227	-85%	101	227	125%	
Year 2	25	4	-84%	2,518	472	-81%	101	118	17%	
Year 3	35	14	-60%	3,525	1,479	-58%	101	106	5%	0%
Year 4	45	24	-47%	4,532	2,486	-45%	101	104	3%	
Year 5	45	24	-47%	4,532	2,486	-45%	101	104	3%	
Years 1-5 Total	**45**	**24**	**-47%**	**16,618**	**7,150**	**-57%**	**101**	**104**	**3%**	

5

6 Notes:

7 • Market conditions deteriorated after the project was completed with all utilities installed including
8 natural gas.

9 • The project is currently being actively marketed with attachments likely deferred for economic
10 reasons. This project is owned by Shadow Mountain Resorts and was intended to attract
11 customers from Alberta looking for luxury resort accommodations as such; the attachment
12 potential is highly contingent upon economic recovery.

Table 79: 2010 FEI Top 5 – Pinot Noir Drive Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
4110027393	Pinot Noir Dr	Original Forecast	Actual	Variance %
Year 1	Mains	$ 84,220	$ 46,420	-45%
	Service lines and meters	$ -	$ 17,158	
	Year 1 Total	$ 84,220	$ 63,578	-25%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 21,363	$ 10,919	-49%
	Year 2 Total	$ 21,363	$ 10,919	-49%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 21,363	$ -	-100%
	Year 3 Total	$ 21,363	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 12,462	$ -	-100%
	Year 4 Total	$ 12,462	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$139,408**	**$74,496**	**-47%**

Table 80: 2010 FEI Top 5 – Pinot Noir Drive Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Pinot Noir Dr 4110027393	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	0	11	-	0	830	-	0	75	-	
Year 2	24	18	-25%	2,417	1,669	-31%	101	93	-8%	
Year 3	48	42	-13%	4,834	4,086	-15%	101	97	-3%	0%
Year 4	62	56	-10%	6,244	5,496	-12%	101	98	-3%	
Year 5	62	56	-10%	6,244	5,496	-12%	101	98	-3%	
Years 1-5 Total	**62**	**56**	**-10%**	**19,739**	**17,577**	**-11%**	**101**	**98**	**-3%**	

Notes:

- The costs for this project have been reduced by a CIAC of approximately $18,000.

Table 81: 2010 FEI Top 5 Main Extensions Profitability Index

2010 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Whiskey Jack Drive	0.78	0.32	-59%
Gislason Avenue	0.96	0.86	-10%
Progress Way	1.05	1.38	32%
Highway 95A	0.93	0.46	-51%
Pinot Noir Dr	0.84	1.01	20%
Years 1-5 Total	**0.91**	**0.80**	**-12%**

8.1 2010 FEVI Top 5 Results

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 82 & 83	Table 84 & 85	Table 86 & 87	Table 88 & 89	Table 90 & 91	Table 92
Riverstone Drive	Norton Road	Chilco Road	Fifth Street	Rosstown Road	Top 5 PI Results

Table 82: 2010 FEVI Top 5 – Riverstone Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550001060	Riverstone Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 75,139	$ 108,523	44%
	Service lines and meters	$ 40,527	$ 33,787	-17%
	Year 1 Total	$ 115,667	$ 142,310	23%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$115,667**	**$142,310**	**23%**

Table 83: 2010 FEVI Top 5 – Riverstone Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Riverstone Drive 5550001060	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	45	23	-49%	3,150	617	-80%	70	27	-62%	0%
Year 2	45	23	-49%	3,150	617	-80%	70	27	-62%	
Year 3	45	23	-49%	3,150	617	-80%	70	27	-62%	
Year 4	45	23	-49%	3,150	617	-80%	70	27	-62%	
Year 5	45	23	-49%	3,150	617	-80%	70	27	-62%	
Years 1-5 Total	**45**	**23**	**-49%**	**15,750**	**3,086**	**-80%**	**70**	**27**	**-62%**	

Notes:

- This project was Geo-Priced before manual estimating rules for larger mains came into place. As such the cost per meter was not representative due to rocky ground and higher pressure requirements.

Table 84: 2010 FEVI Top 5 – Norton Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110027102	Norton Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 47,346	$ 64,952	37%
	Service lines and meters	$ 13,509	$ 35,256	161%
	Year 1 Total	$ 60,855	$ 100,208	65%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 13,509	$ 4,407	-67%
	Year 2 Total	$ 13,509	$ 4,407	-67%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 13,509	$ -	-100%
	Year 3 Total	$ 13,509	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$87,874**	**$104,615**	**19%**

Table 85: 2010 FEVI Top 5 – Norton Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Norton Road 4110027102	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	15	24	60%	1,050	526	-50%	70	22	-69%	0%
Year 2	30	27	-10%	2,100	661	-69%	70	24	-65%	
Year 3	45	42	-7%	3,150	1,711	-46%	70	41	-42%	
Year 4	45	42	-7%	3,150	1,711	-46%	70	41	-42%	
Year 5	45	42	-7%	3,150	1,711	-46%	70	41	-42%	
Years 1-5 Total	**45**	**42**	**-7%**	**12,600**	**6,320**	**-50%**	**70**	**41**	**-42%**	

Table 86: 2010 FEVI Top 5 – Chilco Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550001973	Chilco Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 80,573	$ 90,789	13%
	Service lines and meters	$ 19,813	$ -	-100%
	Year 1 Total	$ 100,387	$ 90,789	-10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 19,813	$ 32,318	63%
	Year 2 Total	$ 19,813	$ 32,318	63%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 18,913	$ -	-100%
	Year 3 Total	$ 18,913	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$139,113**	**$123,107**	**-12%**

Table 87: 2010 FEVI Top 5 – Chilco Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Chilco Road 5550001973	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	22	0	-100%	1,060	0	-100%	48	0	-100%	0%
Year 2	44	22	-50%	2,017	287	-86%	46	13	-72%	
Year 3	65	43	-34%	2,878	1,148	-60%	44	27	-40%	
Year 4	65	43	-34%	2,878	1,148	-60%	44	27	-40%	
Year 5	65	43	-34%	2,878	1,148	-60%	44	27	-40%	
Years 1-5 Total	**65**	**43**	**-34%**	**11,711**	**3,731**	**-68%**	**44**	**27**	**-40%**	

Notes:

- $38,000 in additional mains costs have been added due to the completion of the final phase of the main install which was on hold since 2010.

1 **Table 88: 2010 FEVI Top 5 – Fifth Street Costs**

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550001073	Fifth Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 16,230	$ 38,633	138%
	Service lines and meters	$ 16,211	$ 29,380	81%
	Year 1 Total	$ 32,441	$ 68,013	110%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,469	
	Year 2 Total	$ -	$ 1,469	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$32,441**	**$69,482**	**114%**

2

3

4 **Table 89: 2010 FEVI Top 5 – Fifth Street Attachments, Consumption and Use per Customer**

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Fifth Street 5550001073	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	18	20	11%	9,914	4,847	-51%	551	242	-56%	0%
Year 2	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Year 3	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Year 4	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Year 5	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Years 1-5 Total	**18**	**21**	**17%**	**49,570**	**30,532**	**-38%**	**551**	**306**	**-44%**	

5

6 Notes:

7
- This project was a conversion of an older mall to plaza type shopping facility.

8
- Additional costs were incurred for the unplanned removal of old steel mains and existing below grade service lines that were no longer required. Actual costs are also higher due to asphalt and sidewalk cuts and repairs related to new service lines.

9

10

Table 90: 2010 FEVI Top 5 – Rosstown Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550003357	Rosstown Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 19,464	$ 37,675	94%
	Service lines and meters	$ 2,702	$ 1,469	-46%
	Year 1 Total	$ 22,166	$ 39,144	77%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 2,702	$ -	-100%
	Year 2 Total	$ 2,702	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 901	$ -	-100%
	Year 3 Total	$ 901	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 901	$ -	-100%
	Year 4 Total	$ 901	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$26,669**	**$39,144**	**47%**

Table 91: 2010 FEVI Top 5 – Rosstown Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Rosstown Road 5550003357	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	3	1	-67%	221	11	-95%	74	11	-85%	0%
Year 2	6	1	-83%	549	11	-98%	92	11	-88%	
Year 3	7	2	-71%	609	71	-88%	87	36	-59%	
Year 4	8	3	-63%	628	90	-86%	79	30	-62%	
Year 5	8	3	-63%	628	90	-86%	79	30	-62%	
Years 1-5 Total	**8**	**3**	**-63%**	**2,635**	**274**	**-90%**	**79**	**30**	**-62%**	

Notes:

- This project incurred additional costs due to last minute changes in hydro location. As a result the main location had to be moved in accordance with industry standards. Additional backfill material and compaction charges were also incurred.
- Poor market conditions have impacted the number of attachments on this main. Attachment potential still exists and the Companies will continue to monitor & canvas for opportunities.

1 **Table 92: 2010 FEVI Top 5 Main Extensions Profitability Index**

2010 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Riverstone Drive	1.15	0.15	-87%
Norton Road	1.38	0.57	-59%
Chilco Road	1.17	0.47	-60%
Fifth Street	17.38	7.05	-59%
Rosstown Road	0.81	0.00	-100%
Years 1-5 Total	**4.38**	**1.65**	**-62%**

2

3

9 2009 MAIN EXTENSIONS

The following section summarizes the attachment and consumption results for the 2009 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2009 gas year (November 01, 2008 to October 31, 2009).
- The actual results in this section are from November 01, 2008 to October 31, 2011.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 3.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables is used to indicate a forecast year.

9.1 2009 FEI Random Sample Results

The tables below summarize the sample aggregate 2009 main extension results for FEI.

1 **Table 93: 2009 FEI Aggregate Main Extensions Costs**

2009 SAMPLE MAIN EXTENSIONS - COSTS				
FEI	Cost of Installation ($)			
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 873,525	$ 944,648	8%
	Service lines and meters	$ 616,783	$ 617,105	0%
	Year 1 Total	$ 1,490,308	$ 1,561,753	5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 217,513	$ 397,389	83%
	Year 2 Total	$ 217,513	$ 397,389	83%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 174,805	$ 250,911	44%
	Year 3 Total	$ 174,805	$ 250,911	44%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 120,178	$ -	-100%
	Year 4 Total	$ 120,178	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 90,382	$ -	-100%
	Year 5 Total	$ 90,382	$ -	-100%
Years 1-5 Total		**$2,093,186**	**$2,210,053**	**6%**

2

3

4 **Table 94: 2009 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer**

2009 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	621	455	-27%	75,052	33,360	-56%	121	73	-39%
Year 2	840	748	-11%	95,200	50,330	-47%	113	67	-41%
Year 3	1,016	933	-8%	111,478	59,046	-47%	110	63	-42%
Year 4	1,137	1,054	-7%	122,782	70,350	-43%	108	67	-38%
Year 5	1,228	1,145	-7%	131,524	79,092	-40%	107	69	-36%
Years 1-5 Total	**1,228**	**1,145**	**-7%**	**536,036**	**292,176**	**-45%**	**107**	**69**	**-36%**

5

6

Table 95: 2009 FEI Aggregate Main Extensions Profitability Index

2009 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.44	0.79	-45%
Years 1-5 Total	**1.44**	**0.79**	**-45%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[16].
- The variance between years 1-3 forecast and year's 1-3 actual costs is attributable to a combination of variance in costs and attachments.
- 3 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

9.2 2009 FEVI Random Sample Results

The tables below summarize the sample aggregate 2009 main extension results for FEVI.

[16] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2009 Year End, submitted to the Commission August 18, 2010.

Table 96: 2009 FEVI Aggregate Main Extensions Costs

2009 SAMPLE MAIN EXTENSIONS - COSTS				
		Cost of Installation ($)		
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 796,757	$ 951,042	19%
	Service lines and meters	$ 447,529	$ 257,108	-43%
	Year 1 Total	$ 1,244,286	$ 1,208,150	-3%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 47,922	$ 140,828	194%
	Year 2 Total	$ 47,922	$ 140,828	194%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,961	$ 65,892	175%
	Year 3 Total	$ 23,961	$ 65,892	175%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 18,550	$ -	-100%
	Year 4 Total	$ 18,550	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 1,546	$ -	-100%
	Year 5 Total	$ 1,546	$ -	-100%
Years 1-5 Total		**$1,336,265**	**$1,414,870**	**6%**

Table 97: 2009 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2009 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	579	199	-66%	39,644	6,882	-83%	68	35	-49%
Year 2	641	308	-52%	43,890	9,146	-79%	68	30	-57%
Year 3	672	359	-47%	45,438	10,764	-76%	68	30	-56%
Year 4	696	383	-45%	46,403	11,729	-75%	67	31	-54%
Year 5	698	385	-45%	46,493	11,819	-75%	67	31	-54%
Years 1-5 Total	**698**	**385**	**-45%**	**221,868**	**50,340**	**-77%**	**67**	**31**	**-54%**

Table 98: 2009 FEVI Aggregate Main Extensions Profitability Index

2009 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	**Original Years 1-5 Forecast**	**Re-calculated PI with actual data**	**Variance %**
Year 1 Year 2 Year 3 Year 4 Year 5	1.63	0.30	-82%
Years 1-5 Total	**1.63**	**0.30**	**-82%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[17].
- The variance between years 1-3 forecast and year's 1-3 actual costs is attributable to a combination of variance in costs and attachments.
- 5 FEVI customers made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

9.3 2009 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 99 & 100	Table 101 & 102	Table 103 & 104	Table 105 & 106	Table 107 & 108	Table 109
Tronson Road	2nd Avenue	Upper Hyde Creek	108 Avenue	University Way	Top 5 PI Results

[17] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2009 Year End, submitted to the Commission August 18, 2010.

Table 99: 2009 FEI Top 5 –Tronson Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000158	Tronson Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 337,574	$ 254,932	-24%
	Service lines and meters	$ -	$ -	
	Year 1 Total	$ 337,574	$ 254,932	-24%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ 8,138	-84%
	Year 2 Total	$ 49,660	$ 8,138	-84%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ 6,781	-86%
	Year 3 Total	$ 49,660	$ 6,781	-86%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ -	-100%
	Year 4 Total	$ 49,660	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 54,627	$ -	-100%
	Year 5 Total	$ 54,627	$ -	-100%
Years 1-5 Total		**$541,182**	**$269,851**	**-50%**

Table 100: 2009 FEI Top 5 – Tronson Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Tronson Road 5550000158	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	0	0	0%	0	0	0%	0	0	0%	0%
Year 2	50	6	-88%	5,878	202	-97%	118	34	-71%	
Year 3	100	11	-89%	11,756	359	-97%	118	33	-72%	
Year 4	150	61	-59%	17,634	6,237	-65%	118	102	-13%	
Year 5	205	116	-43%	24,100	12,703	-47%	118	110	-7%	
Years 1-5 Total	**205**	**116**	**-43%**	**59,368**	**19,502**	**-67%**	**118**	**110**	**-7%**	

Notes:

- House starts have been slow in this development and account for the lower than anticipated attachment rates. The property continues to be developed and is being marketed. Attachments are expected to increase as house starts begin.
- This project is a large phased subdivision, due to economic reasons the developer has put on hold the final phase. The Company continues to monitor the situation with the developer

Table 101: 2009 FEI Top 5 – 2nd Avenue Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550002931	2nd Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 192,852	$ 180,407	-6%
	Service lines and meters	$ 47,674	$ 10,850	-77%
	Year 1 Total	$ 240,526	$ 191,257	-20%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 65,552	$ 109,858	68%
	Year 2 Total	$ 65,552	$ 109,858	68%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 78,464	$ 155,972	99%
	Year 3 Total	$ 78,464	$ 155,972	99%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 66,545	$ -	-100%
	Year 4 Total	$ 66,545	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 45,688	$ -	-100%
	Year 5 Total	$ 45,688	$ -	-100%
Years 1-5 Total		**$496,774**	**$457,087**	**-8%**

Table 102: 2009 FEI Top 5 – 2nd Avenue Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI 2nd Avenue 5550002931	Attachments			Consumption (GJ)			Use per Customer			Ramp-Up Factor
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	
Year 1	48	8	-83%	4,685	350	-93%	98	44	-55%	0%
Year 2	114	89	-22%	11,127	3,581	-68%	98	40	-59%	
Year 3	193	204	6%	18,837	8,360	-56%	98	41	-58%	
Year 4	260	271	4%	25,376	14,899	-41%	98	55	-44%	
Year 5	306	317	4%	29,733	19,256	-35%	97	61	-37%	
Years 1-5 Total	**306**	**317**	**4%**	**89,758**	**46,445**	**-48%**	**97**	**61**	**-37%**	

Table 103: 2009 FEI Top 5 – Upper Hyde Creek Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
4110025291	Upper Hyde Creek	Original Forecast	Actual	Variance %
Year 1	Mains	$ 61,300	$ 103,212	68%
	Service lines and meters	$ 114,219	$ 92,227	-19%
	Year 1 Total	$ 175,519	$ 195,439	11%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 46,113	
	Year 2 Total	$ -	$ 46,113	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,356	
	Year 3 Total	$ -	$ 1,356	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$175,519**	**$242,908**	**38%**

Table 104: 2009 FEI Top 5 – Upper Hyde Creek Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Upper Hyde Creek 4110025291	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	115	68	-41%	13,161	4,610	-65%	114	68	-41%	
Year 2	115	102	-11%	13,161	7,280	-45%	114	71	-38%	
Year 3	115	103	-10%	13,161	7,330	-44%	114	71	-38%	0%
Year 4	115	103	-10%	13,161	7,330	-44%	114	71	-38%	
Year 5	115	103	-10%	13,161	7,330	-44%	114	71	-38%	
Years 1-5 Total	**115**	**103**	**-10%**	**65,805**	**33,879**	**-49%**	**114**	**71**	**-38%**	

Notes:

- Cost overruns associated with a bridge crossing have resulted in significant cost increases.

Table 105: 2009 FEI Top 5 – 108 Avenue Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEI 5550000647	108 Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 85,317	$ 97,272	14%
	Service lines and meters	$ 14,898	$ 54,251	264%
	Year 1 Total	$ 100,215	$ 151,523	51%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ 20,344	37%
	Year 2 Total	$ 14,898	$ 20,344	37%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ 35,263	137%
	Year 3 Total	$ 14,898	$ 35,263	137%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ -	-100%
	Year 4 Total	$ 14,898	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 17,878	$ -	-100%
	Year 5 Total	$ 17,878	$ -	-100%
Years 1-5 Total		**$162,787**	**$207,130**	**27%**

Table 106: 2009 FEI Top 5 – 108 Avenue Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			
FEI 108 Avenue 5550000647	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	15	40	167%	1,638	2,122	30%	109	53	-51%	
Year 2	30	55	83%	3,319	2,925	-12%	111	53	-52%	
Year 3	45	81	80%	5,000	4,057	-19%	111	50	-55%	0%
Year 4	60	96	60%	6,681	5,738	-14%	111	60	-46%	
Year 5	78	114	46%	8,699	7,756	-11%	112	68	-39%	
Years 1-5 Total	**78**	**114**	**46%**	**25,337**	**22,598**	**-11%**	**112**	**68**	**-39%**	

Table 107: 2009 FEI Top 5 – University Way Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000180	University Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 182,972	$ 97,020	-47%
	Service lines and meters	$ -	$ 1,356	
	Year 1 Total	$ 182,972	$ 98,377	-46%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 993	$ 1,356	37%
	Year 2 Total	$ 993	$ 1,356	37%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 25,823	$ 1,356	-95%
	Year 3 Total	$ 25,823	$ 1,356	-95%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 25,823	$ -	-100%
	Year 4 Total	$ 25,823	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 24,830	$ -	-100%
	Year 5 Total	$ 24,830	$ -	-100%
Years 1-5 Total		**$260,442**	**$101,089**	**-61%**

Table 108: 2009 FEI Top 5 – University Way Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
University Way 5550000180	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	0	1	-	0	1,046	-	0	1,046	-	
Year 2	1	2	100%	1,750	1,046	-40%	1,750	523	-70%	
Year 3	27	3	-89%	4,913	1,067	-78%	182	356	95%	0%
Year 4	53	29	-45%	8,076	4,230	-48%	152	146	-4%	
Year 5	78	54	-31%	10,489	6,643	-37%	134	123	-9%	
Years 1-5 Total	**78**	**54**	**-31%**	**25,228**	**14,031**	**-44%**	**134**	**123**	**-9%**	

Notes:

- The third phase of this project has been put on hold as there are ROW conflicts and construction issues around crossing an existing large diameter transmission pressure gas pipeline.
- Only the first 325m of this project have been installed to date. Academy Hill Prep School is currently attached to this main in addition to the show home for the new 48 unit vertical-subdivision condominium (Academy Hill) currently under construction. The 48 residential meters and 1 commercial meter at Academy Hill should be active in the fall of 2013.
- Phase 2 of Academy Hill (another 30 unit condominium) will be constructed within the next 2-3 years.

1 **Table 109: 2009 FEI Top 5 Main Extensions Profitability Index**

2009 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Tronson Road	0.88	0.50	-43%
2nd Avenue	1.25	0.77	-38%
Upper Hyde Creek	1.47	0.57	-61%
108 Avenue	1.02	0.70	-31%
University Way	0.85	0.66	-22%
Years 1-5 Total	**1.09**	**0.64**	**-41%**

2

3 ## 9.1 2009 FEVI Top 5 Results

4 The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 110 & 111	Table 112 & 113	Table 114 & 115	Table 116 & 117	Table 118 & 119	Table 120
Shawnigan Lake Road	West Coast Road	Wild Ridge Way	Hammond Bay Road	Kettle Creek Station	Top 5 PI Results

5

Table 110: 2009 FEVI Top 5 – Shawnigan Lake Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000958	Shawnigan Lake Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 695,444	$ 1,918,065	176%
	Service lines and meters	$ 127,534	$ 49,096	-62%
	Year 1 Total	$ 822,978	$ 1,967,161	139%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 77,520	
	Year 2 Total	$ -	$ 77,520	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 21,642	$ 16,796	-22%
	Year 3 Total	$ 21,642	$ 16,796	-22%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$844,620**	**$2,061,477**	**144%**

Table 111: 2009 FEVI Top 5 – Shawnigan Lake Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Shawnigan Lake Road 5550000958	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	165	38	-77%	14,000	6,828	-51%	85	180	112%	
Year 2	165	98	-41%	14,000	9,926	-29%	85	101	19%	
Year 3	193	111	-42%	20,315	10,203	-50%	105	92	-13%	0%
Year 4	193	111	-42%	20,315	10,203	-50%	105	92	-13%	
Year 5	193	111	-42%	20,315	10,203	-50%	105	92	-13%	
Years 1-5 Total	**193**	**111**	**-42%**	**88,945**	**47,363**	**-47%**	**105**	**92**	**-13%**	

Notes:

- Please refer to the “Terasen Gas (Vancouver Island) Inc. Shawnigan Lake Main Extension Report” submitted to the Commission on November 2, 2010 for a detailed review.

Table 112: 2009 FEVI Top 5 – West Coast Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000027	West Coast Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 261,699	$ 401,092	53%
	Service lines and meters	$ 155,360	$ -	-100%
	Year 1 Total	$ 417,059	$ 401,092	-4%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,292	
	Year 3 Total	$ -	$ 1,292	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$417,059**	**$402,384**	**-4%**

Table 113: 2009 FEVI Top 5 – West Coast Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
West Coast Road 5550000027	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	201	0	-100%	14,070	0	-100%	70	0	-100%	
Year 2	201	0	-100%	14,070	0	-100%	70	0	-100%	
Year 3	201	1	-100%	14,070	19	-100%	70	19	-73%	0%
Year 4	201	1	-100%	14,070	19	-100%	70	19	-73%	
Year 5	201	1	-100%	14,070	19	-100%	70	19	-73%	
Years 1-5 Total	**201**	**1**	**-100%**	**70,350**	**58**	**-100%**	**70**	**19**	**-73%**	

Notes:

- Mains and service stubs were required to be installed prior to paving due to alignment of main. After main install, market conditions severely deteriorated due to the recession resulting in attachment and load projections not being realized. The development is currently being marketed and attachment potential still exists.
- This project also consisted of a large 4" main used to service the subdivision on a higher elevation. The geo-priced cost forecasting was performed prior to the Companies implementing an enhancement for projects using large diameter pipe. As a result, the forecast costs were underestimated.
- While the project is completed and lots are for sale, housing starts in this development are not occurring, so while opportunity exists and the Companies are engaged in discussing energy solutions with builders, there are no housing starts at this time.

Table 114: 2009 FEVI Top 5 – Wild Ridge Way Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110024485	Wild Ridge Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 67,155	$ 112,793	68%
	Service lines and meters	$ 49,468	$ 41,344	-16%
	Year 1 Total	$ 116,623	$ 154,137	32%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 11,628	
	Year 2 Total	$ -	$ 11,628	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 3,876	
	Year 3 Total	$ -	$ 3,876	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$116,623	$169,641	45%

Table 115: 2009 FEVI Top 5 – Wild Ridge Way Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Wild Ridge Way 4110024485	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	64	32	-50%	4,480	1,207	-73%	70	38	-46%	0%
Year 2	64	41	-36%	4,480	1,523	-66%	70	37	-47%	
Year 3	64	44	-31%	4,480	1,700	-62%	70	39	-45%	
Year 4	64	44	-31%	4,480	1,700	-62%	70	39	-45%	
Year 5	64	44	-31%	4,480	1,700	-62%	70	39	-45%	
Years 1-5 Total	64	44	-31%	22,400	7,831	-65%	70	39	-45%	

Notes:

- There were severe issues with the topography surrounding this development. A prevalence of bedrock combined with drastic changes in elevation led to a difficult running line and a significant increase in costs.

Table 116: 2009 FEVI Top 5 – Hammond Bay Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEVI 4110001271	Hammond Bay Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 66,340	$ 79,513	20%
	Service lines and meters	$ 15,459	$ 6,460	-58%
	Year 1 Total	$ 81,799	$ 85,973	5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ 11,628	-25%
	Year 2 Total	$ 15,459	$ 11,628	-25%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ 10,336	-33%
	Year 3 Total	$ 15,459	$ 10,336	-33%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ -	-100%
	Year 4 Total	$ 15,459	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$128,175	$107,937	-16%

Table 117: 2009 FEVI Top 5 – Hammond Bay Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			
FEVI Hammond Bay Road 4110001271	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	20	5	-75%	1,400	183	-87%	70	37	-48%	0%
Year 2	40	14	-65%	2,800	337	-88%	70	24	-66%	
Year 3	60	22	-63%	3,531	510	-86%	59	23	-61%	
Year 4	80	42	-48%	4,262	1,241	-71%	53	30	-45%	
Year 5	80	42	-48%	4,262	1,241	-71%	53	30	-45%	
Years 1-5 Total	80	42	-48%	16,255	3,511	-78%	53	30	-45%	

Notes:

- Due to economic reasons the development of this project has slowed dramatically.
- The upper portion of this subdivision is steep and rocky which has contributed to higher costs.

Table 118: 2009 FEVI Top 5 – Kettle Creek Station Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550002297	Kettle Creek Station	Original Forecast	Actual	Variance %
Year 1	Mains	$ 57,178	$ 70,261	23%
	Service lines and meters	$ 15,459	$ 11,628	-25%
	Year 1 Total	$ 72,636	$ 81,889	13%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 7,752	
	Year 2 Total	$ -	$ 7,752	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 14,686	$ -	-100%
	Year 3 Total	$ 14,686	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 14,686	$ -	-100%
	Year 5 Total	$ 14,686	$ -	-100%
Years 1-5 Total		**$102,008**	**$89,641**	**-12%**

Table 119: 2009 FEVI Top 5 – Kettle Creek Station Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Kettle Creek Station 5550002297	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	20	9	-55%	1,747	204	-88%	87	23	-74%	
Year 2	20	15	-25%	1,747	409	-77%	87	27	-69%	
Year 3	39	15	-62%	3,407	409	-88%	87	27	-69%	80%
Year 4	39	15	-62%	3,407	409	-88%	87	27	-69%	
Year 5	58	34	-41%	5,067	2,069	-59%	87	61	-30%	
Years 1-5 Total	**58**	**34**	**-41%**	**15,375**	**3,501**	**-77%**	**87**	**61**	**-30%**	

Notes:

- The anticipated load for this project was not being realized and as a result the Company stopped all new installations until a viable business plan could be worked out with the developer. The developer has since decided not to continue with planned gas connections for the remainder of the subdivision.
- The small size homes in this subdivision have low energy demand and consumers have not been interested in incurring costs to connect and install gas appliances.

Table 120: 2009 FEVI Top 5 Main Extensions Profitability Index

2009 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Shawnigan Lake Road	0.93	0.20	-78%
West Coast Road	1.56	-0.11	-107%
Wild Ridge Way	1.91	0.33	-83%
Hammond Bay Road	1.18	0.38	-68%
Kettle Creek Station	1.73	0.64	-63%
Years 1-5 Total	**1.46**	**0.29**	**-80%**

10 2008 MAIN EXTENSIONS

The following section summarizes the attachment and consumption results for the 2008 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2008 gas year (November 01, 2007 to October 31, 2008).
- The actual results in this section are from November 01, 2007 to October 31, 2011.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 4.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables is used to indicate a forecast year.

10.1 2008 FEI Random Sample Results

The tables below summarize the sample aggregate 2008 main extension results for FEI.

Table 121: 2008 FEI Aggregate Main Extensions Costs

2008 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 352,046	$ 437,819	24%
	Service lines and meters	$ 465,993	$ 248,642	-47%
	Year 1 Total	$ 818,039	$ 686,462	-16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 24,576	$ 112,620	358%
	Year 2 Total	$ 24,576	$ 112,620	358%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,631	$ 143,335	507%
	Year 3 Total	$ 23,631	$ 143,335	507%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 13,233	$ 86,294	552%
	Year 4 Total	$ 13,233	$ 86,294	552%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,288	$ -	-100%
	Year 5 Total	$ 12,288	$ -	-100%
Years 1-5 Total		**$891,766**	**$1,028,711**	**15%**

Table 122: 2008 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2008 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	493	170	-66%	57,640	13,883	-76%	117	82	-30%
Year 2	519	247	-52%	60,148	20,231	-66%	116	82	-29%
Year 3	544	345	-37%	62,557	26,963	-57%	115	78	-32%
Year 4	558	404	-28%	63,905	30,613	-52%	115	76	-34%
Year 5	571	417	-27%	65,148	31,856	-51%	114	76	-33%
Years 1-5 Total	**571**	**417**	**-27%**	**309,398**	**123,546**	**-60%**	**114**	**76**	**-33%**

Table 123: 2008 FEI Aggregate Main Extensions Profitability Index

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1			
Year 2			
Year 3	1.60	0.75	-54%
Year 4			
Year 5			
Years 1-5 Total	**1.60**	**0.75**	**-54%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[18].
- The variance between years 1-4 forecast and year's 1-4 actual costs is attributable to a combination of variance in costs and attachments.
- Four FEI customers made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

10.2 2008 FEVI Random Sample Results

The tables below summarize the sample aggregate 2008 main extension results for FEVI.

[18] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2008 Year End, submitted to the Commission April 3, 2009.

Table 124: 2008 FEVI Aggregate Main Extensions Costs

2008 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 264,194	$ 298,877	13%
	Service lines and meters	$ 244,921	$ 155,944	-36%
	Year 1 Total	$ 509,114	$ 454,821	-11%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 30,856	$ 64,848	110%
	Year 2 Total	$ 30,856	$ 64,848	110%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 1,929	$ 121,976	6225%
	Year 3 Total	$ 1,929	$ 121,976	6225%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 49,408	
	Year 4 Total	$ -	$ 49,408	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,821	$ -	-100%
	Year 5 Total	$ 4,821	$ -	-100%
Years 1-5 Total		**$546,720**	**$691,053**	**26%**

Table 125: 2008 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2008 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	254	101	-60%	12,561	4,712	-62%	49	47	-6%
Year 2	286	143	-50%	14,482	5,972	-59%	51	42	-18%
Year 3	288	222	-23%	14,589	7,730	-47%	51	35	-31%
Year 4	288	254	-12%	14,589	8,743	-40%	51	34	-32%
Year 5	293	259	-12%	14,839	8,993	-39%	51	35	-31%
Years 1-5 Total	**293**	**259**	**-12%**	**71,060**	**36,151**	**-49%**	**51**	**35**	**-31%**

Table 126: 2008 FEVI Aggregate Main Extensions Profitability Index

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	**Original Years 1-5 Forecast**	**Re-calculated PI with actual data**	**Variance %**
Year 1 Year 2 Year 3 Year 4 Year 5	1.30	0.71	-45%
Years 1-5 Total	**1.30**	**0.71**	**-45%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[19].
- The variance between years 1-4 forecast and year's 1-4 actual costs is attributable to a combination of variance in costs and attachments.
- Four FEVI customers made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

10.3 2008 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 127 & 128	Table 129 & 130	Table 131 & 132	Table 133 & 134	Table 135 &136	Table 137
Trans-Canada Highway	Juniper Road	Crystal Creek Drive	61A Avenue	Rio Drive	Top 5 PI Results

[19] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2008 Year End, submitted to the Commission April 3, 2009.

Table 127: 2008 FEI Top 5 –Trans-Canada Highway Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000560	Trans-Canada Hwy	Original Forecast	Actual	Variance %
Year 1	Mains	$ 950,140	$ 838,718	-12%
	Service lines and meters	$ 128,550	$ 77,518	-40%
	Year 1 Total	$ 1,078,689	$ 916,236	-15%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 136,112	$ 52,654	-61%
	Year 2 Total	$ 136,112	$ 52,654	-61%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 103,029	$ 20,476	-80%
	Year 3 Total	$ 103,029	$ 20,476	-80%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 114,372	$ 2,925	-97%
	Year 4 Total	$ 114,372	$ 2,925	-97%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 945	$ -	-100%
	Year 5 Total	$ 945	$ -	-100%
Years 1-5 Total		**$1,433,147**	**$992,291**	**-31%**

Table 128: 2008 FEI Top 5 – Trans-Canada Highway Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Trans-Canada Hwy 5550000560	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	136	53	-61%	24,473	1,191	-95%	180	22	-88%	
Year 2	280	89	-68%	41,906	4,394	-90%	150	49	-67%	
Year 3	389	103	-74%	59,399	5,355	-91%	153	52	-66%	0%
Year 4	510	105	-79%	74,587	5,434	-93%	146	52	-65%	
Year 5	511	106	-79%	79,801	10,648	-87%	156	100	-36%	
Years 1-5 Total	**511**	**106**	**-79%**	**280,166**	**27,022**	**-90%**	**156**	**100**	**-36%**	

Notes:

- The mains were installed after all lots were registered and roads and other utilities were in place. Market conditions deteriorated shortly afterward and development of the property did not occur as anticipated. The property is currently in foreclosure.
- The load and customer attachment assumptions, while not achieved, may still materialize as the lots remain undeveloped but are being marketed.
- Twenty-two additional homes have recently been completed and have yet to be sold.
- The project costs have been reduced by a CIAC of approximately $89,000.

Table 129: 2008 FEI Top 5 – Juniper Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS						
FEI		Cost of Installation ($)				
4110009212	Juniper Road	Original Forecast		Actual		Variance %
Year 1	Mains	$	24,141	$	121,522	403%
	Service lines and meters	$	9,452	$	-	-100%
	Year 1 Total	$	33,593	$	121,522	262%
Year 2	Mains	$	-	$	-	
	Service lines and meters	$	9,452	$	-	-100%
	Year 2 Total	$	9,452	$	-	-100%
Year 3	Mains	$	-	$	-	
	Service lines and meters	$	10,397	$	-	-100%
	Year 3 Total	$	10,397	$	-	-100%
Year 4	Mains	$	-	$	-	
	Service lines and meters	$	6,617	$	5,850	-12%
	Year 4 Total	$	6,617	$	5,850	-12%
Year 5	Mains	$	-	$	-	
	Service lines and meters	$	5,671	$	-	-100%
	Year 5 Total	$	5,671	$	-	-100%
Years 1-5 Total			**$65,731**		**$127,372**	**94%**

Table 130: 2008 FEI Top 5 – Juniper Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Juniper Road 4110009212	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	10	0	-100%	1,250	0	-100%	125	0	-100%	
Year 2	20	0	-100%	2,500	0	-100%	125	0	-100%	
Year 3	31	0	-100%	3,875	0	-100%	125	0	-100%	0%
Year 4	38	4	-89%	4,750	162	-97%	125	40	-68%	
Year 5	44	10	-77%	5,500	912	-83%	125	91	-27%	
Years 1-5 Total	**44**	**10**	**-77%**	**17,875**	**1,074**	**-94%**	**125**	**91**	**-27%**	

Notes:

- Significant costs were incurred on this project related to soil compaction and road base repair.
- All lots for this project are fully serviced by the main. Twenty-four lots have been purchased but homes have yet to be constructed. The project has been delayed due to the recession but is now beginning to recover.
- The developer is currently engaged in attracting investors.

Table 131: 2008 FEI Top 5 – Crystal Creek Drive Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550001699	Crystal Creek Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 30,876	$ 116,239	276%
	Service lines and meters	$ 20,795	$ 2,925	-86%
	Year 1 Total	$ 51,671	$ 119,165	131%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 7,313	
	Year 2 Total	$ -	$ 7,313	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 2,925	
	Year 3 Total	$ -	$ 2,925	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 7,313	
	Year 4 Total	$ -	$ 7,313	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$51,671**	**$136,716**	**165%**

Table 132: 2008 FEI Top 5 – Crystal Creek Drive Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Crystal Creek Drive 5550001699	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	22	2	-91%	3,070	284	-91%	140	142	2%	0%
Year 2	22	7	-68%	3,070	725	-76%	140	104	-26%	
Year 3	22	9	-59%	3,070	881	-71%	140	98	-30%	
Year 4	22	14	-36%	3,070	1,630	-47%	140	116	-17%	
Year 5	22	14	-36%	3,070	1,630	-47%	140	116	-17%	
Years 1-5 Total	**22**	**14**	**-36%**	**15,350**	**5,150**	**-66%**	**140**	**116**	**-17%**	

Notes:

- A very rocky ground surface added to the time it took to install the main. As a result, costs increased significantly. Also, the developer had already previously paved some of running line for the main which had to be repaired once the install was complete.
- Market downturn occurred after gas main installation which slowed housing starts. Potential to realize attachment and load assumptions still exists as lots remain undeveloped and are being marketed.

Table 133: 2008 FEI Top 5 – 61A Avenue Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000251	61A Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 77,032	$ 114,145	48%
	Service lines and meters	$ 47,261	$ 40,953	-13%
	Year 1 Total	$ 124,293	$ 155,098	25%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 56,713	$ 61,429	8%
	Year 2 Total	$ 56,713	$ 61,429	8%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 57,658	$ 86,294	50%
	Year 3 Total	$ 57,658	$ 86,294	50%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 29,252	
	Year 4 Total	$ -	$ 29,252	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$238,665**	**$332,073**	**39%**

Table 134: 2008 FEI Top 5 – 61A Avenue Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
61A Avenue 5550000251	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	50	28	-44%	4,827	2,018	-58%	97	72	-25%	
Year 2	110	70	-36%	10,619	5,264	-50%	97	75	-22%	
Year 3	171	129	-25%	16,507	9,419	-43%	97	73	-24%	0%
Year 4	171	149	-13%	16,507	10,822	-34%	97	73	-25%	
Year 5	171	149	-13%	16,507	10,822	-34%	97	73	-25%	
Years 1-5 Total	**171**	**149**	**-13%**	**64,967**	**38,344**	**-41%**	**97**	**73**	**-25%**	

Notes:

- The unanticipated depth of dig, conflicts with foreign utilities and unforeseen paving costs are all factors that drove up the cost of this job.

Table 135: 2008 FEI Top 5 – Rio Drive Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550001989	Rio Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 90,674	$ 85,549	-6%
	Service lines and meters	$ 37,809	$ -	-100%
	Year 1 Total	$ 128,482	$ 85,549	-33%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 37,809	$ 2,925	-92%
	Year 2 Total	$ 37,809	$ 2,925	-92%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 11,343	$ 20,476	81%
	Year 3 Total	$ 11,343	$ 20,476	81%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 16,089	
	Year 4 Total	$ -	$ 16,089	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$177,634**	**$125,040**	**-30%**

Table 136: 2008 FEI Top 5 – Rio Drive Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Rio Drive 5550001989	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	40	0	-100%	2,438	0	-100%	61	0	-100%	0%
Year 2	80	2	-98%	4,876	31	-99%	61	16	-74%	
Year 3	92	16	-83%	5,547	524	-91%	60	33	-46%	
Year 4	92	27	-71%	5,547	895	-84%	60	33	-45%	
Year 5	92	27	-71%	5,547	895	-84%	60	33	-45%	
Years 1-5 Total	**92**	**27**	**-71%**	**23,955**	**2,346**	**-90%**	**60**	**33**	**-45%**	

Notes:

- This project is a multi-phased project which was severely impacted by the economic downturn.
- The owner is actively engaged in marketing the development and the project is making a slow recovery.
- The project costs have been reduced by a CIAC of approximately $27,000.

Table 137: 2008 FEI Top 5 Main Extensions Profitability Index

2008 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Trans-Canada Hwy	1.00	0.08	-92%
Juniper Road	1.70	0.01	-99%
Crystal Creek Drive	1.00	0.15	-85%
61A Avenue	1.38	0.68	-51%
Rio Drive	1.00	0.08	-92%
Years 1-5 Average	**1.22**	**0.20**	**-84%**

10.1 2008 FEVI Top 5 Results

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 138 & 139	Table 140 & 141	Table 142 & 143	Table 144 & 145	Table 146 &147	Table 148
Players Drive	French Road	Hutchinson Road	Sewell Road	Phillips Road	Top 5 PI Results

Table 138: 2008 FEVI Top 5 – Players Drive Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000862	Players Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 237,392	$ 219,182	-8%
	Service lines and meters	$ 71,355	$ -	-100%
	Year 1 Total	$ 308,746	$ 219,182	-29%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,544	
	Year 2 Total	$ -	$ 1,544	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 77,200	
	Year 3 Total	$ -	$ 77,200	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 29,336	
	Year 4 Total	$ -	$ 29,336	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$308,746**	**$327,262**	**6%**

Table 139: 2008 FEVI Top 5 – Players Drive Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Players Drive 5550000862	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	74	0	-100%	13,307	0	-100%	180	0	-100%	
Year 2	74	1	-99%	13,307	32	-100%	180	32	-82%	
Year 3	74	51	-31%	13,307	1,994	-85%	180	39	-78%	0%
Year 4	74	70	-5%	13,307	2,927	-78%	180	42	-77%	
Year 5	74	70	-5%	13,307	2,927	-78%	180	42	-77%	
Years 1-5 Total	**74**	**70**	**-5%**	**66,535**	**7,879**	**-88%**	**180**	**42**	**-77%**	

Notes:

- This development is a multi-phased project which was severely impacted by the economic downturn but has since recovered.

1 **Table 140: 2008 FEVI Top 5 – French Road Costs**

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110025230	French Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 68,993	$ 159,929	132%
	Service lines and meters	$ 48,213	$ 13,896	-71%
	Year 1 Total	$ 117,205	$ 173,825	48%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 15,440	
	Year 2 Total	$ -	$ 15,440	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 24,704	
	Year 3 Total	$ -	$ 24,704	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 13,896	
	Year 4 Total	$ -	$ 13,896	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$117,205	$227,865	94%

2

3

4 **Table 141: 2008 FEVI Top 5 – French Road Attachments, Consumption and Use per Customer**

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
French Road 4110025230	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	50	9	-82%	3,500	346	-90%	70	38	-45%	0%
Year 2	50	19	-62%	3,500	594	-83%	70	31	-55%	
Year 3	50	35	-30%	3,500	1,043	-70%	70	30	-57%	
Year 4	50	44	-12%	3,500	1,271	-64%	70	29	-59%	
Year 5	50	44	-12%	3,500	1,271	-64%	70	29	-59%	
Years 1-5 Total	50	44	-12%	17,500	4,524	-74%	70	29	-59%	

5

6 Notes:

7 • Unforeseen rock, asphalt removal and restoration of roads required large quantities materials and
8 resources resulting in increased costs.

9 • Additional staking due to revised development plans also contributed to cost overruns.

10

Table 142: 2008 FEVI Top 5 – Hutchinson Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110016828	Hutchinson Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 81,857	$ 86,812	6%
	Service lines and meters	$ 39,534	$ 10,808	-73%
	Year 1 Total	$ 121,392	$ 97,620	-20%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 32,785	$ 41,688	27%
	Year 2 Total	$ 32,785	$ 41,688	27%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 43,232	
	Year 3 Total	$ -	$ 43,232	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 3,088	
	Year 4 Total	$ -	$ 3,088	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$154,176**	**$185,628**	**20%**

Table 143: 2008 FEVI Top 5 – Hutchinson Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Hutchinson Road 4110016828	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	41	7	-83%	2,255	172	-92%	55	25	-55%	0%
Year 2	75	34	-55%	4,125	870	-79%	55	26	-53%	
Year 3	75	62	-17%	4,125	1,526	-63%	55	25	-55%	
Year 4	75	64	-15%	4,125	1,551	-62%	55	24	-56%	
Year 5	75	64	-15%	4,125	1,551	-62%	55	24	-56%	
Years 1-5 Total	**75**	**64**	**-15%**	**18,755**	**5,670**	**-70%**	**55**	**24**	**-56%**	

Notes:

- This subdivision was developed for the lots to be sold directly to individual builders and was ready for building right at the time of the economic downturn. It is making a slow recovery.

Table 144: 2008 FEVI Top 5 – Sewell Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110008114	Sewell Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 45,187	$ 21,412	-53%
	Service lines and meters	$ 9,643	$ 26,248	172%
	Year 1 Total	$ 54,830	$ 47,660	-13%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,464	$ 3,088	-79%
	Year 2 Total	$ 14,464	$ 3,088	-79%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 16,984	
	Year 3 Total	$ -	$ 16,984	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,544	
	Year 4 Total	$ -	$ 1,544	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$69,293**	**$69,276**	**0%**

Table 145: 2008 FEVI Top 5 – Sewell Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Sewell Road 4110008114	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	10	17	70%	1,100	679	-38%	110	40	-64%	0%
Year 2	25	19	-24%	2,750	824	-70%	110	43	-61%	
Year 3	25	30	20%	2,750	1,110	-60%	110	37	-66%	
Year 4	25	31	24%	2,750	1,121	-59%	110	36	-67%	
Year 5	25	31	24%	2,750	1,121	-59%	110	36	-67%	
Years 1-5 Total	**25**	**31**	**24%**	**12,100**	**4,855**	**-60%**	**110**	**36**	**-67%**	

Notes:

- The existing utility ROW for this project was unable to accommodate the main. As a result construction took place in the existing roadway. Significant costs were incurred for both digging and road restoration.
- The project costs have been reduced by a CIAC of approximately $6,000.

Table 146: 2008 FEVI Top 5 – Phillips Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000935	Phillips Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 196,787	$ 75,286	-62%
	Service lines and meters	$ 82,926	$ -	-100%
	Year 1 Total	$ 279,713	$ 75,286	-73%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 964	$ 1,544	60%
	Year 2 Total	$ 964	$ 1,544	60%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$280,677**	**$76,830**	**-73%**

Table 147: 2008 FEVI Top 5 – Phillips Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Phillips Road 5550000935	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	86	0	-100%	4,620	0	-100%	54	0	-100%	0%
Year 2	87	1	-99%	4,670	35	-99%	54	35	-35%	
Year 3	87	1	-99%	4,670	35	-99%	54	35	-35%	
Year 4	87	1	-99%	4,670	35	-99%	54	35	-35%	
Year 5	87	1	-99%	4,670	35	-99%	54	35	-35%	
Years 1-5 Total	**87**	**1**	**-99%**	**23,300**	**139**	**-99%**	**54**	**35**	**-35%**	

Notes:

- This project is a large phased subdivision which has been severely impacted by the economic downturn.
- Only 50 percent of the main has been completed, with no anticipation of full completion as it is currently on hold by the developer. Many of the lots still have no construction activity.

1 **Table 148: 2008 FEVI Top 5 Main Extensions Profitability Index**

2008 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Players Drive	1.55	0.26	-83%
French Road	1.22	0.16	-87%
Hutchinson Road	1.40	0.47	-66%
Sewell Road	1.03	0.51	-51%
Phillips Road	0.88	-0.08	-109%
Years 1-5 Average	**1.22**	**0.26**	**-78%**

2

3

11 CONCLUSION AND NEXT STEPS

For the 2012 MX Report, the Companies believe they are in full compliance with the Commission's Decision and Order No. G-152-07, and Order No. G-6-08. This Report also addresses the requests of Commission Staff and the related additional items identified in Letters No. L-67-11, L-19-12 and L-60-12.

The Companies have identified an area of concern within the MX Test methodology, specifically on the forecasting of individual customers' consumption levels. The current practice of forecasting new consumption values that are based on the historic usage of all existing current customers is not reflective of the behaviors of new customers and the challenges they face when connecting to Companies' systems.

Going forward, the Companies will continue to apply the format and methodologies used in the 2012 MX Report to future year end compliance reports as the Companies have directly applied the suggestions of Commission Staff and believe the reporting changes will ensure more meaningful and useful information on main extensions.

Appendix A

FEI TARIFF GENERAL TERMS AND CONDITIONS DEFINITIONS

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of FortisBC Energy and in the rate schedules of FortisBC Energy the following words have the following meanings:

Basic Charge	Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge – calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places.	C
Biogas	Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.	
Biomethane	Means Biogas purified or upgraded to pipeline quality gas.	
Biomethane Service	Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales	
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to (i) any commission that is a successor to such commission, and (ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia	
Carbon Offsets	Means what FortisBC Energy will purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.	
Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.	
Commodity Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.	

Commodity Unbundling Service	Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.
Conversion Factor	Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.
Customer	Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.
Delivery Point	Means the outlet of the Meter Set unless otherwise specified in the Service Agreement.
Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
Financing Agreement	Means an agreement under which FortisBC Energy provides financing to a Customer for improving the energy efficiency of a Premises, or a part of a Premises. C/N
First Nations	Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.
Franchise Fees	Means the aggregate of all monies payable by FortisBC Energy to a municipality or First Nations (i) for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within a municipality or First Nations lands (formerly, reserves within the *Indian Act*), (ii) relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), and (iii) relating, if applicable, to the value of Gas transported by FortisBC Energy through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).

FortisBC Energy	Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number 0778288.	
FortisBC Energy *System*	Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time.	
Gas	Means natural gas (including odorant added by FortisBC Energy) and propane and Biomethane.	
Gas Service	Means the delivery of Gas through a Meter Set.	
***General Terms & Conditions of* FortisBC Energy**	Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.	
Gigajoule	Means a measure of energy equal to one billion joules used for billing purposes.	
Heat Content	Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).	
Hour	Means any consecutive 60 minute period.	
Hydronic Heating System	A heating / cooling system where water is heated or cooled and distributes hot water through pipes to radiators or to another style of water-to-air heat exchanger.	
Landlord	A Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.	
Loan	Means the principal amount of financing provided by FortisBC Energy to a Customer, plus interest charged by FortisBC Energy on the amount of financing and any applicable fees and late payment charges.	C/N
Main	Means pipes used to carry Gas for general or collective use for the purposes of distribution.	
Main Extension	Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, the installation of any required pressure regulating facilities and upgrading of existing Mains, or pressure regulating facilities on private property.	
Marketer	Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.	

Meter Set	Means an assembly of FortisBC Energy owned metering and ancillary equipment and piping.
Midstream Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
Month	Means a period of time, for billing purposes, of 27 to 34 consecutive Days.
Municipal Operating Fees	Has the same meaning as Franchise Fees.
Other Service	Means the provision of Service other than Gas Service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.
Other Service Charges	Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Franchise Fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic. C
Premises	Means a building, a separate unit of a building, or machinery together with the surrounding land.
Profitability Index	The revenue to cost ratio comparing the revenues expected from a Main Extension project to the expected costs over a set period of time.
Rate Schedule	Means a schedule attached to and forming part of this Tariff, which sets out the charges for Service and certain other related terms and conditions for a class of Service.
Residential Premises	Means the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments.
Residential Service	Means firm Gas Service provided to a Residential Premises.
Rider	Means an additional charge or credit attached to a rate.
Seasonal Service	Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st.

Service	Means the provision of Gas Service or other service by FortisBC Energy.
Service Agreement	Means an agreement between FortisBC Energy and a Customer for the provision of Service.
Service Area	Has the meaning set out at the end of the Definitions in these General Terms & Conditions.
Service Header	Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main.
Service Line	Means that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.
Service Related Charges	Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges.
Standard Fees & Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various fees and charges relating to Service provided by FortisBC Energy as approved from time to time by the British Columbia Utilities Commission. C
Temporary Service	Means the provision of Service for what FortisBC Energy determines will be a limited period of time.
Tenant	A Person who has the temporary use and occupation of real property owned by another Person.
Thermal Energy	Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.
Thermal Metering	Thermal / heat meters measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.

Vertical Subdivision	Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor.
Year	Means a period of 12 consecutive Months.
10^3m^3	Means 1,000 cubic metres.

C

Appendix B

FEI TARIFF GENERAL TERMS AND CONDITIONS SECTION 12

12. Main Extensions

12.1 **System Expansion -** FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 **Ownership -** All extensions of the Gas distribution system will remain the property of FortisBC Energy.

12.3 **Economic Test -** All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual main extension.

12.4 **Revenue -** The projected revenue to be used in the economic test will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used and the effect variations in weather conditions throughout the applicable Service Area have on consumption. Customers who intend to install both high efficiency gas fired space (namely an Energy Star rated furnace or boiler) and water heating appliances (tankless water heaters, or water heaters with efficiency rating of 78 percent or greater), will receive a credit of 10 percent of the volume otherwise used for both appliances. Customers who intend to install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification will receive a credit of 15 percent of the volume otherwise used for both. In addition, the projected revenue from Application Fees will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion will be considered.

12.5 **Costs -** The total costs to be used in the economic test include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the Main Extension;

(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 **Contributions in Aid of Construction** - If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

12.7 **Contributions Paid by Connecting Customers -** The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years after the Main Extension is built. As additional contributions are received from Customers connecting to the main extension, partial refunds will be made to those Customers who had previously made contributions. At the end of the fifth Year, all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension Contribution Agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

12.8 **Refund of Contributions** - A review will be performed annually, or more often at the Company's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due,

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

12.9 **Extensions to Contributory Extensions** - When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension, the new extension will be evaluated using the Main Extension Test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension. The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 **Security** - In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

Appendix C

EES CONSULTING MAIN EXTENSION REPORT

FortisBC Energy Utilities
Review of System Extension Policies

March 2013

Prepared by:

EES Consulting

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

A registered professional engineering corporation with offices in
Kirkland, WA and Portland, OR

Telephone: (425) 889-2700 Facsimile: (425) 889-2725

March 15, 2013

Mr. Brent Graham
Manager, Energy Product & Services
FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8

SUBJECT: Mains Extension Policy Review

Dear Mr. Graham:

Please find attached the Review of FortisBC Energy Utilities' System Extension Policies report prepared by EES Consulting. The conclusions and recommendations contained within this report are based upon industry practice and generally accepted rate setting principles.

This study has been developed independently by EES Consulting, with information provided by FEU staff, as needed. The findings, conclusions and recommendations of this report provide the basis for the development of an alternative approach for determining the system extension allowances for new FEU customers.

Thank you for the opportunity to assist FEU in this rate setting process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary S. Saleba
President

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

Telephone: 425 889-2700 Facsimile: 425 889-2725

A registered professional engineering corporation with offices in
Kirkland, WA and Portland, OR

Contents

Executive Summary

This report is provided to the FortisBC Energy Utilities (FEU) to address whether its current System Extension polices are consistent with the practices of other gas utilities and to determine whether any changes should be made to the policies. It is intended to provide background information for future engagement with the Commission and FEU stakeholders regarding a review of its system extension policies.

The FEU currently use a cost-benefit analysis to determine the amount of service line and main extension allowance available for each new connection. The service extension is covered by the Service Line Cost Allowance (SLCA) and is applied to customers where the proposed service line can be attached to an existing distribution main. For customers that require an extension of distribution mains, the necessary calculations to determine the allowance are completed within the Main Extension (MX) test, which includes the cost of the complete requirement for a meter, service line and any extensions of distribution mains required to serve the customer.

The SLCA is a standard allowance of $1535 per customer to cover the cost of the service line. It was calculated using the MX test along with standardized assumptions and is therefore consistent with the main extension calculations.

The MX test, used when a main extension is required, includes a 20-year cost-benefit analysis showing both the revenues and the costs associated with each new connection project. Revenues are based on expected consumption given the appliances that are planned for installation. Ongoing expenses for O&M, property taxes and income taxes are deducted from the revenue. Costs include the cost of the meter, service, plus a detailed planning estimate of the cost of any required extensions in distribution mains. Both the revenues and costs are discounted to present value (PV), and the P.I. ratio is calculated as the PV of revenues divided by the PV of costs. The FEU will fund individual projects that have a profitability index (P.I.) of 0.8 or better. On an overall basis, a P.I. target of 1.1 is set for the utilities.

EES Consulting conducted a survey of system extension policies for gas utilities in Canada and the Western U.S. In general, all utilities use some form of cost-benefit analysis. For the utilities in Canada, the approach was similar to the MX test performed by the FEU and calculations were performed for each connection project. There were some differences in the number of years included in the analysis, with most utilities using 30-40 years rather than the 20 years used by the FEU. Other minor differences occurred, however, it was confirmed that the FEU policy is in keeping with standard practice.

One alternative approach that was found was the use of standard extension credits for each appliance rather than FEU's method of using a cost-benefit for each main extension which attempts to quantify the consumption levels specific to the customer(s). This is similar to the standardized SLCA amount used by FEU for service extensions. This approach was found in

Oregon and California. The standard credits were based on an underlying cost-benefit analysis, however, the standardization led to a more transparent and easy to administer policy.

While the current FEU system extension policies are consistent with standard practice, it faces the following issues:

- It does not capture the benefits of future projects that are less costly due to the current main extension.
- It does not capture the benefit of fixed costs and overhead costs being spread over a greater number of customers.
- As the usage per customer declines over time, the MX test leads to new customers receiving a smaller main extension allowance than what was provided to customers in the past
- The upward pressure on rates resulting from reduced consumption has not been accounted for in the MX test.
- The annual reporting of actual revenues and costs highlights the impacts of reduced consumption, but is applied only to new customers. It does not account for the fact that those same reductions impact existing customers.
- There is a lack of transparency as new customers are not able to translate adding multiple gas appliances to a direct reduction in installation costs without the assistance of the FEU to perform complex MX test calculations.
- The use of a 20-year period is inconsistent with other utilities and is shorter than the useful life of the facilities in question and the corresponding depreciation period used for accounting and regulatory purposes.
- The use of a 27% overhead factor added to the cost of the extension may be inconsistent with the amount of overhead that is capitalized when the facilities are placed in rate base.

To resolve these issues, EES recommends that the MX test be adjusted to reflect consistency in the number of years used and the overhead factor applied. Further, the alternative where standard appliance credits are used would be beneficial for FEU customers and should be adopted for the residential class. These standard credits can be readily determined using the current MX test and policy. This approach would provide greater transparency to customers, would simplify the construction and planning process for the utility, and eliminate the need for annual reporting. Non-residential classes would continue to use the MX test approach, with the adjustments that have been discussed.

Additionally, FEU should begin to offer financing for the customer contributions required as a result of system extensions. This financing could be a 5-year loan at the weighted cost of capital for large projects, as is currently offered to FortisBC electric customers. For smaller customers, and as an option for large customers, a 24-month interest-free installment plan would be also appropriate.

Existing FEU Main Extension Policy

EES Consulting was retained by the FortisBC Energy Utilities (FEU) to review and assist the utility in assessing its current System Extension policy. This review looks at the current policy and the accompanying MX test as compared to the policies and tests used at other natural gas utilities.

Service lines are addressed in Section 10 of the General Terms and Conditions for each FEU utility while main extensions are addressed in Section 12. In general, FEU uses a cost-benefit approach for assessing the amount of credit allowed for both service extensions and main extensions; however, the service extension has been standardized into a fixed credit per residential and small commercial customer. For this report, the term system extension is used to include the policies related to both service and main extensions as a whole. The service extension is covered with the Service Line Cost Allowance (SLCA) and is applied to customers where the proposed service line can be attached to an existing distribution main. For customers that require an extension of distribution mains, the necessary calculations to determine the allowance are completed within the MX test, which includes the cost of the complete requirement for a meter, service line and any extensions of distribution mains required to serve the customer.

General Policy

The process for obtaining a new natural gas service for a customer of FEU, whether it is a single residential home, a new sub-division of homes or a commercial/industrial account, is to submit an application for service with the utility. This starts the system extension process whereby the utility reviews the location relative to existing infrastructure and determines the costs associated with attaching the new customer(s) to the existing system.

If the customer can be attached to an existing distribution main, the service extension falls under the SLCA covered in Section 10. Using the cost-benefit analysis contained in the MX test, a standardized credit for a service extension was first established in 1996 using a standard consumption level per customer. The SLCA was updated in 2007 to a standardized credit of $1535 for all FEU residential and small commercial customers. The service line and meter cost are covered by the utility up to the $1535 allowance, and the customer is liable for any amounts that exceed that level.

If the customer requires an addition to distribution mains, the main extension falls under the MX test covered in Section 12. The utility works with the customer to establish the expected gas consumption based on the appliances to be installed and the climate zone in which the customer falls. In many cases it is the home developer that requests the new service, even though they are not the eventual gas customer. For purposes of this report we will refer to the customer to include both direct customers and any developers or contractors acting on behalf of the eventual customers.

To determine the amount of allowance that FEU will provide to the customer that requires a main extension, a cost-benefit analysis is done using the MX test model. Note that the allowance resulting from the MX test is not additive to the SCLA as the service line and meter costs are included within the MX test. Both the costs of the installation and the expected usage for the customer are inputs into the MX test model. In general, if the profitability Index (P.I.) for the customer is equal to or greater than 0.8 the utility will pay for the cost of the installation. If the P.I. is below 0.8 the customer is required to make a customer contribution in the amount that will bring the P.I. to 0.8.

Because rates differ among FEI, FEVI, FEW and FEFN, the MX test differs for each utility and region. The calculations are the same in all cases; however the usage assumptions, costs and rates are customized for each utility. For purposes of this report, it is assumed that all discussions and recommendations encompass FEI, FEVI, FEW and FEFN, but will be referred to generically as FEU.

Of course this is a very general description of the policy and process. The following provides greater details associated with each component.

MX Test Cost Estimates

For each main extension project, FEU staff develops costs for each new customer connection. The estimate includes the cost of the meter as well as the service line. In the case of simple service lines, the utility uses the geo pricing methodology to standardize the cost per line. The price in each case includes a fixed component plus a variable component based on metres of service length. The pricing differs among the 9 regions that are identified. For more complex service lines the utility requires a more detailed manual estimate approach for the specific project. The geo-pricing is updated each year based on actual installations. For extensions to the distribution mains, each project is evaluated and designed by engineering staff to develop the cost of the project. Similar to service lines, FEU staff can use geo-pricing to estimate main extension costs in some cases where it is appropriate.

Some requested main extensions are for service to one customer while in many cases they would apply to a subdivision or development that would include multiple customers. Both the costs and the MX test are considered on a project-by-project basis rather than on an individual customer basis within the project.

In addition to the project-specific costs, an adder of 27% is applied to the service line and main extension costs to reflect the cost of overheads and administration. An additional 0.5% is added to account for working capital.

The estimated project cost is one of the inputs into the MX test model.

MX Test Customer Usage and Revenue

As costs are compared to revenues within the MX test, the revenues must be developed based on expected customer usage. The customers expected to connect to the project are looked at over a five-year period as they may not all connect at the same time. Usage estimates are based on standard annual gigajoules (GJ) of consumption per appliance for each residential customer while more specific estimates of usage are developed for commercial/industrial customers to reflect the size, type of business and gas applications expected for each customer.

FEU develops end-use forecasts for 17 different residential appliance types. The usage forecasts reflect the Residential End Use Study (REUS) undertaken by FEU every 4 years, and are adjusted to reflect 9 different zones. Customers requesting the extension must identify the appliances they plan on installing at the site, which is then used to develop the usage estimates for each connection. It is assumed that usage is consistent from year to year and reflects average weather conditions. The forecast is not designed to take into account the fact that different customers will use gas differently than one another, even with the same appliances.

For those customers that install both a high efficiency water heater and furnace in combination, FEU includes a 10% adder to the consumption estimate when calculating the MX test. For homes or business that are LEED certified, a 15% adder is applied. With these adders, customers are rewarded for installing energy efficient appliances.

The resulting number of customers and usage per year is input into the MX test model.

MX Test Model

The MX Test model has been developed internally by FEU staff to evaluate the P.I. of each main extension project, and the methodology and test parameters have been approved by the Commission in past decisions. As stated above, the primary inputs to the MX test model are the cost of each project and the estimated consumption per year. The methodology is the same for FEI, FEVI, FEW and FEFN; however, the rates for service differ between the utilities.

The model considers the total cost of the project in comparison to the net revenues provided over a period of 20 years. The model assumes all costs and revenues are in current year dollars and are not adjusted to reflect inflation. All revenues and costs are discounted to the present value using a 5% real discount rate. As inflation is excluded from the calculations for both costs and rates, it is appropriate to use a real discount rate as opposed to a nominal discount rate.

Gross revenues are based on consumption times the applicable rate for each customer class and are developed for years 1 through 20. Revenues include the basic charge per customer plus the delivery charge per GJ used but excludes the cost of gas and midstream charges. It is assumed that there are no real increases in delivery rates during the 20-year test period. While FEU does not currently project any real rate increases in the future, the decline in usage per customer over time that is occurring due to energy efficiency may place upward pressure on delivery rates over time. This upward pressure could be offset through growth in new customers.

The MX test is designed to capture the marginal revenues of the utility after annual cash outflows are deducted. This includes the deduction of O&M costs, property taxes, and income taxes.

Within the MX test, the present value of the revenues is divided by the present value of the project cost to calculate the P.I. value. If the P.I. value is below 0.8 for the project, a customer contribution is required and is input into the MX test such that the P.I. value increases to the 0.8 level. Projects that exceed the 0.8 P.I. level are funded by FEU without a customer contribution.

MX Test P.I. Requirements and Reporting

On an individual project basis, FEU uses a minimum 0.8 P.I. target to set the main extension allowance available to the customer. However, on an overall system basis the P.I. target is 1.1. Overall, the utility strives to proceed in a manner that is economic and does not lead to increases in rates as a result of adding new customers to the system. Because there are many projects with P.I. levels above 1.1, allowing a level below 1.1 on an individual basis is appropriate because the various projects will balance each other out and meet the system-wide target.

FEU is required to report results of the main extension projects to the Commission each year. While the MX test and customer contribution is based on an estimated cost, the reporting to the Commission is trued up to reflect the actual installed costs once the project is complete and the actual customer revenue. Because of the numerous extensions each year and the amount of information that was involved in each project, reporting to the Commission was originally set up based on a random sample of projects rather than on all of them. With technological and recordkeeping advancements, FEU now has the capability of readily tracking every project. While FEU has submitted this information to the Commission in addition to the random sample results, the Commission relies on the random sample to determine if FEU is meeting the P.I. target of 1.1.

System Extension Accounting Treatment

The costs associated with new customers are added to the rate base each year, including the full cost of the meter, service and main extension. An overhead amount is added to the cost of the service and main extension and is capitalized along with the direct cost to account for supervision, administration, etc. This capitalized overhead is then a credit in the annual revenue requirements against the various overhead items.

Customer contributions are included in the contribution in aid of construction (CIAC) account and are deducted from the distribution plant amounts to determine the rate base of the utility.

Financing and Security for New Customers

FEU does not provide financing for the customer contributions that are required from certain customers. Full payment of the customer contribution is required before FEU proceeds with the main extension project. This policy has been approved by the Commission in past decisions.

Issues with Current Policies

The theoretical construct for system extensions is that new customers pay their fair share and don't cause existing customers to pay higher delivery rates as a result of the new customers connecting to the system. The FEU approach of looking at marginal revenues in comparison to the cost of connection generally meets this construct. However, it is important to recognize the overall costs and benefits of new customers, even for those factors that are not readily quantified.

For main extensions in areas where growth is an ongoing factor, it is often the case that one main extension will benefit one or more future projects that are downstream. Because those future projects have not been identified at the time of the first extension, they are not quantified in the MX test. The end result may be that the first project has a P.I. level of 0.8 but the extension allows for subsequent projects to be shorter in length with a resulting P.I. level well above 1.1. In this sense, the lower individual threshold used by FEU is appropriate and reflects the interconnection of different projects over time.

A second benefit of new customers is the sharing of fixed costs over a larger number of customers, resulting in a lower cost per customer or per GJ. The nature of the facilities associated with the delivery costs of the gas utility is highly fixed in nature, with a large infrastructure for transmission, storage and general plant. At the current time, FEU's system has sufficient capacity in part due to the fact that usage per customer has been declining over time as a result of energy efficiency in building codes, new appliances, and customer practices. So while new customers require additional distribution facilities, they cause little or no additional cost for transmission, storage, general plant, and administration, resulting in a benefit to existing customers as fixed costs are spread over a greater customer base. It is important to note that the new customers may not actually cause unit rates to fall, but they have the impact of keeping the unit costs from rising as much as a result of reduced usage due to energy efficiency.

Another issue to consider is temporal equality. New customers should be treated on an equitable basis with past customers. As extension costs increase with inflation, they should not be compared directly to the depreciated values of the facilities in place for existing customers. For that reason it is appropriate that the amount of the main extension allowance increases over time to account for inflation. This is captured by the current policy where the allowance is based on retail rates, which increase over time due to inflation and other factors.

While the current method does adequately meet some of the desired qualities of a good main extension policy, there are other areas where it is lacking.

Because usage per customer has become more efficient over time, the usage per appliance forecast has been declining over time, reducing the accompanying revenues in the MX test. Customers that connected in previous periods would have had a higher amount of forecast usage and therefore a higher allowed credit resulting from the MX test. This is true despite the fact that those same customers are now also using less gas as a result of energy efficiency measures. This potentially leads to temporal inequalities between customers.

While FEU has reflected declining usage of its existing customers when estimating consumption levels within the MX test, it has not made a corresponding increase in real delivery rates in the future to reflect this declining consumption level.   This provides an inconsistency within the MX test assumptions. The revenue calculated is reduced due to declining consumption without the effect of the offsetting increase in rates that result from declining usage, providing for a higher barrier for meeting the required P.I. target.

The reporting required by the Commission focuses solely on new customer connections and whether or not they are achieving the results projected with the MX test. If those customers do not use as much energy as projected, the allowance paid for main extensions are questioned. Customers that were connected historically are not included in the required reporting.   As stated above, there may be temporal inequities between customers that connected in different periods, and the difference in the reporting required for new versus existing customers exacerbates that inequity

The complexity of the current MX test model, when compared to other simpler calculations, better reflects the inter-related aspects of consumption, revenues and costs. This not only makes it more difficult to administer but more importantly it is not transparent to the customer and results in confusion and uncertainty for those considering new connections. The customer must provide inputs regarding appliances and usage to FEU, but does not know what impact that will have on their contribution amount until FEU provides them with the MX test result. This makes it difficult for customers to make the connection between appliance selection, increased consumption and cost reduction.

Finally, it is important that the MX test be consistent with other accounting practices at the utility. This may not be the case for the length of time used for calculating revenues or the overhead adder. The 20-year period used for the MX test is not consistent with the useful life and depreciation factors used for distribution mains and services. Also, the 27% overhead factor used within the MX test may not be consistent with the amount of overhead that is capitalized for the distribution mains and services when they are installed.

Survey of Practices by Other Utilities

To determine whether the system extension policies and tests in use at FEU are still in keeping with those of other utilities, and to explore how other utilities may have dealt with some of the issues facing FEU, EES Consulting surveyed the practice of other natural gas utilities in Canada and the Western U.S.

The survey looked at the published policies for system extensions, contacted individuals knowledgeable of the policies, and in some cases reviewed Commission orders regarding system extension policies. In many cases system extension policies have been in place for many years and have not been addressed in regulatory filings. In many cases the policies are less defined and the tests less complex than that used by FEU.

Generally, the gas utilities in Canada use the basic cost-benefit approach in place at FEU but often the tests have somewhat different parameters. Many of the U.S. utilities use a cost-benefit approach that has been standardized so that a standard credit can be applied for each individual appliance.

While the survey considered all customer classes, much of the emphasis is related to residential customers as there are much larger numbers of residential connections each year and the issue of declining use per customer is more prevalent.

Utilities reviewed in the survey include:

- ATCO Gas (Alberta)
- AltaGas Utilities (Alberta)
- SaskEnergy (Saskatchewan)
- Manitoba Gas (Manitoba)
- Union Gas (Ontario)
- Gaz Metro (Quebec)
- Enbridge Gas (New Brunswick)
- Heritage Gas (Nova Scotia)
- Puget Sound Energy (Washington)
- Avista Energy (Washington)
- Northwest Natural Gas (Oregon)
- Pacific Gas & Electric (California)
- Southern California Gas (California)
- San Diego Gas & Electric (California)

After looking at the published system extension policies for these utilities, a follow-up telephone survey was conducted for those utilities that had a general cost-benefit analysis approach. In those cases the policies were lacking in detail regarding the parameters and assumptions in determining the cost-benefit analysis. This section discusses the findings of the survey according to topic area.

General Methodology

All of the utilities surveyed had some type of cost-benefit analysis used to develop their system extension policy, where revenues were compared to the cost of the extension to determine whether a customer was required to make a contribution. The Canadian and Washington state gas utilities all used a basic cost-benefit analysis similar to FEU's MX test process. There were some differences in the parameters, which are covered in greater detail below.

The three utilities in California and Northwest Natural Gas in Oregon used a cost-benefit analysis as the basis to establish standardized amounts of extension allowances per appliance for residential customers. Rather than applying specific parameters to each project, as is the case for FEU's main extension, a standard set of assumptions was used to determine the basic amounts determined for each appliance. The resulting allowance applies to both the service line and main extension. This standardized approach was considered a refinement of the cost-benefit approach rather than a separate methodology and is similar to the SLCA approach used by FEU. Benefits of this approach include transparency to customers as well as in consistency with treating all customers the same within each utility. This approach is discussed in more detail below.

While EES Consulting did not do a complete survey across the entire U.S., it did find one alternative methodology in use in Ohio. Dominion Gas in East Ohio had a main extension policy that provided the cost of the meter, service and up to 100 feet (roughly 30 metres) of main extension for each customer. Because this was not a common practice nor was it an improvement in the methodology used by Fortis BC, we did not collect additional data on this alternative. However, it is likely that this policy has been in place for many years and was originally based on a cost-benefit analysis. Generally, this policy appears to be more generous than the FEU approach in many cases. It is not consistent with FEU's approach to account for the expected use per customer and may not provide cost-effective results for those customers with an incidental amount of gas consumption.

Revenue Calculations

To determine the revenues for the cost-benefit analysis, the expected consumption per customer is the first step involved. For residential customers, the utilities generally use some form of usage forecast that reflects appliance installation and/or the specific region. For residential gas use, utilities generally use standard numbers per appliance for their particular region as the basis for the usage per customer for each particular case. These estimates are typically based on the average actual use of similar customers. Manitoba Gas differs in that they use a standard amount of 100 MCf per residential customer per month rather than a customized number based on which appliances are to be installed. For commercial/industrial customers, the usage forecast is customized and reflects discussions with the potential customer about the installation. FEU is generally consistent with the other utilities in this regard.

Revenues are based on the expected appliances to be installed. None of the utilities surveyed do audits to ensure that the appliances are actually installed. They generally trust that the customers are honest about their plans and will perform only occasional spot checks.

None of the utilities surveyed provide any extra incentive in the system extension calculations to account for the installation of more efficient appliances, as is the case for FEU. Any incentives for efficiency are offered through separate DSM programs. While a direct incentive for efficiency in the system extension policy is not a standard practice, this may be something that FEU wishes to continue to promote energy efficiency in new homes. Developers are generally motivated by upfront costs as they do not pay the ongoing gas bills once they have sold the homes they build. To ensure that new homes are as efficient as possible, continuing the added allowance is advisable. In addition, FEU should not penalize customers for installing energy efficient appliances when setting the amount of the main extension allowance.

Usage per customer is multiplied by current rates as the starting point for revenue calculations in the cost-benefit analyses. In all cases, utilities assume there are no real increases in the rate levels included; however, they are adjusted for inflation. FEU also assumes that rates will remain the same in real terms.

In nearly all cases, revenues for residential customers are calculated over a length of time of 30 to 40 years with revenues discounted to reflect the present value. Heritage Gas uses a 25-year period. Manitoba Gas and SaskEnergy both use 30 years, while AltaGas and Puget Sound Energy use 32 years. Union Gas and Enbridge use a 40-year period. This compares to the FEU calculations that use a 20-year period, making FEU out of sync with the other utilities. In several cases a period of 20 years or less is used for commercial/industrial customers to reflect contract length or greater business risk. This is consistent with the FEU practice for large commercial and industrial customers. As with FEU, the revenues are based on net revenues rather than gross revenues, with annual costs for O&M and taxes deducted. The net revenue is then the amount available to cover the carrying costs of the capital for fixed infrastructure associated with the new customer(s).

The exceptions to this approach are ATCO where a 3 year period is used and Avista where one-third of gross revenues are used. In these two cases, a much smaller level of costs, if any, are deducted from the annual revenues. This approach reflects more of an abbreviated method to determine the allowed main extension credit rather than calculating a full cost-benefit analysis. In fact, Avista does a 40-year full NPV analysis on its larger connections but uses the one-year approach as a simpler but comparable method for the majority of cases. It is also important to note that the Avista rate includes the cost of gas. Because these methods are less complete than what is currently done by FEU, it is not seen as an improvement over the current methodology.

Finally, the utilities all use the weighted cost of capital for discounting the forecast revenues when developing the present value. This is appropriate when inflation is applied to both the revenues and the annual costs. In the case of FEU the calculations are all assumed to be in real terms, excluding inflationary adjustments. The discount rate of 5% is then used to reflect a real rather than a nominal discount rate. This level approximates the difference between the utility's weighted cost of capital and the rate of inflation.

Cost Calculations

In most cases site-specific costs for the connection are provided by engineers or contractors for each utility. For residential customers it is common to also use some standardized costs per unit as is the case with FEU.

All of the utilities surveyed incorporate overhead costs into cost calculations. These overheads include A&G, management and engineering. While FEU uses an overhead adder of 27%, the range for the utilities surveyed run from 9% up to an estimated 50-100%. Note that these will vary considerably based on the accounting practices of each utility and what is included in various accounts. Some utilities may include engineering and management costs in the prices for extensions while others may only look at material and direct installation costs.

For consistency purposes, we believe it is appropriate for the amount of overheads added to the costs used in the MX test to be comparable to the overheads capitalized as part of the amount placed in rate base. FEU should determine if the current 27% amount is in line with the capitalized overhead and make any necessary adjustments.

P.I. Targets and Reporting

The FEU's use of a 0.8 target for the P.I. on an individual basis, along with a 1.1 overall target, is consistent with the practices of the other utilities surveyed. While there are differences among the utilities, FEU is well within the range of options used. Union Gas and Enbridge Gas New Brunswick both use the same targets as FEU. Puget Sound Energy uses a lower 0.75 target while Heritage Gas and Manitoba Gas use a 1.0 target. The other utilities either don't have a set target or look at things in a different manner.

Because of the advantages that main extensions bring relative to future extensions that may feed off of them, because of the uncertainty in forecast revenues, and because there are many instances where the MX test yields a P.I. above the 1.1 level, we believe the current FEU parameters for the P.I. targets are appropriate.

While FEU is required to file annual reporting of actual main extensions, including both the actual costs and revenues, this is not a typical practice for other gas utilities. Only Gaz Metro is required to provide annual reporting on actual extensions, along with an explanation of any differences that occur. Puget Sound Energy files an annual update on actual extensions as a courtesy but it is not required to do so. Many of the other utilities need to file information with their periodic revenue requirements filing showing the projected costs and benefits of distribution expansion projects, as they do with any other capital project. This is also the case for FEU. In some cases specific projects are questioned on occasion and looked at more closely to determine prudency. In the case of ATCO Gas any reporting requirements are being eliminated as part of the recently approved Performance Based Ratemaking (PBR).

Standardized Credit per Appliance

As previously discussed, utilities in Oregon and California have standardized the residential system extension allowance on a per appliance basis. The standardized values are based on a typical cost-benefit analysis, however, and in that sense are consistent with the FEU practice. The standardized rates for this year are shown in the following table.

	Water Heating	Space Heating	Oven/Range	Dryer Stub
PG&E	$529	$649	$57	$22
So Cal Gas	$441	$503	$77	$107
SDG&E	$554	$479	$99	$140
Northwest Natural**	$2100	$2875	$850	$850

** Not additive

For the California utilities, the approach is based on a combined Order from the Public Utilities Commission of the State of California (CPUC) and is consistent among the three utilities. While the methodology is the same, each utility uses their own assumptions about usage, rates and demographics. Usage per appliance assumptions are based on the Residential Appliance Saturation Study (RASS) conducted by the California Energy Commission (CEC). The RASS is an end use survey similar to what is done by FEU and reflects the average usage resulting from a sample of all existing customers of the utility.

The cost-benefit analysis is based on a formula where the Allowance equals Net Revenues divided by the Cost-of-Service Factor. Rather than a full blown year-by-year analysis, the Cost-of-Service factor reflects the annualized Cost of Ownership. The result is very similar to the MX test approach used by FEU, but uses a simplistic formula to represent the same theoretical concept. Because this calculation is less complete than FEU's current MX test calculations, we do not believe it should be considered in place of the current method.

The California methodology was last reviewed in Decision 07-07-019, which was based on applications submitted in 2005. The decision made some slight modifications from past practice to ensure that gas usage per appliance was based on usage within each utility's service area rather than a state-wide average and that the COS factor reflects a 60 year period with replacement costs included during that time. The Decision also confirmed the policy that the utilities offer uniform line extension allowances throughout their service territories. The actual allowance values per appliance are periodically updated to reflect current rates.

Note that the allowance values per appliance are additive for the California utilities. Because the climate and demographics are quite different from that in B.C., the allowances would differ if calculated for FEU.

For Northwest Natural, rather than additive amounts per appliance, the allowances are total amounts based on the appliance with the highest usage. For example, if the customer installs space heating it is assumed they will likely have gas water heat as well and the allowance is greater than if they have water heat without space heat. The allowance is lowest for those customers without space or water heat installed.

Financing and Security

Like FEU, most of the utilities surveyed require new customers to pay for any customer contributions up front prior to construction. There are a few isolated cases where some type of financing is available. Gaz Metro allows customers to pay contributions over 24 monthly installments. Puget Sound Energy does not have a published policy regarding financing but will on occasion allow installment payments, without interest, over a short time period on a negotiated basis for large projects. Union Gas allows new customers to pay the 1.5% late fee amount as a way to defer full payment on required contributions. Both Manitoba Gas and Heritage Gas have financing available through an outside company.

Note that FortisBC offers financing of customer contributions for its electric customers. Financing is provided for contributions that exceed $2,000 and are limited to a total of $10,000 per applicant. The financing requires a 20% down payment, is available for a 1 to 5 year period, uses a rate equal to the weighted cost of capital, and is subject to approval of credit for the applicant.

For large customers, there are often additional security requirements to reflect the risk associated with the new customer. ATCO uses a contract demand level with a take or pay clause to ensure revenues are sufficient to cover the costs of the extension. This is consistent with FEU's practice for large customers. Avista secures letters of credit or insurance bonds for large customers. For smaller customers that are new to the system it is common practice to require a small security deposit outside of the system extension process.

Alternative Methods and Recommendations

Based on the utilities surveyed, FEU appears to be fairly consistent with the utilities in Canada in its use of the MX test and current P.I. targets. The current cost-benefit approach is relatively consistent throughout the utilities surveyed, with differences primarily in the underlying assumptions rather than in the methodology. While a few utilities offered a somewhat different approach to calculating the cost-benefit, none of those alternative calculations were as thorough as FEU's current method that considers a long-term present value of costs and benefits.

There are a few areas that should be adjusted in the FEU MX test to be more consistent with the other utilities and with FEU's own accounting practices, which are explained in more detail below.

The standardized credit per appliance approach used in California and Oregon offers an alternative that is still based on an underlying cost-benefit analysis and is consistent with FEU's fixed amount for the SLCA. This approach may have some clear benefits and could be adopted in a manner consistent with the current FEU policies. This alternative is further considered in greater detail below.

Continue Current Individual MX Test Approach

The FEU's current system extension policies and MX test are for the most part consistent with other utilities in Canada. The approach has been in place for some time and is currently working adequately. There are, however, some issues that it does not address well. Continuing with the current policy as it is would require no changes to the work the utility does now and would not require additional review or regulatory process for the Commission. The SLCA for service extensions and MX test for main extensions meet the theoretical standard of having new customers cover any costs of their connection that are not already covered by the existing rate levels.

There are several areas where the current policy and calculations are lacking. This includes:

1. The inconsistency between the MX test period of 20 years and the longer useful life of the facilities
2. The potential inconsistency between the 27% overhead adder and the adder that is actual capitalized with the distribution rate base additions
3. The reduction in use per appliance that has been occurring, leading to inequities between past and current customer allowances
4. The uncertainty associated with assumed consumption for each customer
5. The administrative burden of completing a MX test for each main extension
6. The administrative burden of tracking and reporting actual results for each customer

7. The lack of transparency for the customer
8. The lack of financing available to customers for their customer contribution

The current approach could be continued and meet the overall theoretical construct provided that a few adjustments are made to resolve some of the inconsistencies. However, there are some issues that would remain with the current approach even after adjustments.

Adopt Standard Credit per Appliance

The standardized credit per appliance approach that is in place in Oregon and California provides a greater level of transparency to the customer and would provide a simplification of the process that now requires individual assumptions and calculations for each project.

While the credit per appliance method is a new method it combines several of the approaches already in place at FEU. It is similar to the SLCA in that it is based on a fixed amount that was developed from a cost-benefit analysis and does not require a separate calculation for each service extension. However, it differs from the SLCA in that it would be based on individual appliances rather than a common usage assumption for all customers across all utilities. Compared to the main extension policy, the credit per appliance would be similar in terms of the underlying assumptions and use of the MX test to develop the credits, and the assumptions would differ by utility as is presently the case. It would differ in that the assumptions would be averaged within each utility rather than differing by sub-region, and it would not require a separate calculation for each extension.

This standard credit approach is still based on a cost-benefit analysis and would therefore still meet the current theoretical construct and be consistent with the overall approach used by most utilities surveyed. If FEU were to adopt this standard credit per appliance approach it is recommended that it base the results on the current MX test and the underlying assumptions. It should also apply to both service extensions and main extensions rather than having a separate SLCA and main extension calculation. To arrive at standard credit per appliance amounts, we would suggest the following steps:

1. Start with the existing MX test for each of the utilities.
2. The length of time used should be adjusted beyond 20 years to reflect the useful life of the distribution mains, services and meters.
3. The overhead adder should be adjusted to reflect the amounts actually used when capitalizing overhead costs to the distribution mains account.
4. For each utility a standard use per appliance should be developed. This amount may differ between the utilities but would be consistent for all customers within each utility. The amount would reflect the average use of appliances currently in place rather than the use for newly installed efficient appliances. These usage levels would allow future customers to receive an allowance comparable to what was provided to customers in

the past. In addition, it would not penalize new customers for installing more efficient appliances.

5. A base level for the credit would be developed by assuming 1 GJ or less of usage for 1 customer. The amount of costs that could be supported by this level of usage and still meet the 0.8 target P.I. level would be established as the base amount. Because of the basic charge built into the rate, some revenues exist even when a minimal use of gas is assumed. This base amount would be applied for all new customers as the starting point for the credit. Additional amounts per appliance would be added to the base amount.
6. For each optional appliance, the usage level would be input in the MX test for one customer. The amount of costs that could be covered by this usage would be determined. Only the incremental amount beyond the base amount established in step 5 would be attributable to the appliance.
7. A schedule of allowances for the base amount and for each appliance would be determined for each of the utilities.
8. The current 10% adder for installing a combined high efficiency furnace and water heater and 15% adder for LEED certification would be quantified into a fixed dollar amount and be added to the standard credit if applicable. The amounts of these credits should also be reviewed to determine the appropriate levels required to achieve the desired energy efficiency.
9. Customers would receive an allowance up to the maximum amount for all the appliances to be installed for all customers to be connected within each project. In no case would the amount paid exceed the actual costs of the project installation for service and main extensions.

These steps would result in a standard list of credit amounts per appliance that would be consistent with what is offered to customers today. While the approach is based on what is offered in California and Oregon, it would be customized to reflect the current FEU policy. One difference is that it would apply to more appliances than just those offered in California because additional appliances are already accounted for in the current MX test. A second difference would be in offering a base amount to which appliance credits would be added. This is consistent with how revenues are currently calculated in the MX test with basic charges contributing to the overall revenues. This differs from the simplified California cost-benefit calculation where revenue calculations are tied to average revenue per unit rather than the actual tariff amounts.

While the standard credit approach is well suited for the residential class, non-residential classes would need to continue with individualized MX test calculations for each customer. There may be the potential to provide some standardization for businesses that are similar to one another; however, it is likely to be more expeditious to continue with the current individualization.

By using the existing MX test, which has been approved by the Commission, to develop the resulting standard credits, less oversight would be required than with a completely new approach. At the same time, the assumptions used to develop the standard credits could be reviewed and tested on a periodic basis without the need to examine the entire calculation each year. Amounts could be adjusted on a percentage basis to reflect any changes in the underlying delivery rates.

Other Issues

Two others issues to be addressed are the annual reporting requirements for FEU and the ability to offer financing for capital contributions.

The annual reporting requirements for actual costs and revenues for main extensions are inconsistent with standard practice in the industry, as most utilities are not required to submit after the fact reporting. While it is appropriate to determine whether or not the MX test results are valid, there are some inherent issues associated with the reporting. Previously we raised the issue of temporal inequities as usage is declining over time. While the annual reporting may detect differences in actual usage levels compared to the assumptions made in the MX test, it is not required for historic connections that may also be facing declining consumption. Further, basing main extension allowances on the basis of new more efficient appliance penalizes those customers that are making appropriate energy use decisions.

If the standard credit per appliance method is adopted in the future, the need for annual reporting would be eliminated as the standardized amounts would be thoroughly reviewed and approved prior to implementation. Even without a change to a standard credit, we would recommend that the annual review be eliminated or conducted less frequently to be consistent with other utilities.

Adding an option for financing of capital contributions would be beneficial and would be consistent with what is offered to FortisBC electric customers. Adopting a policy identical to that offered by the electric utility for large contributions with a 20% down payment, up to 5 year term and a borrowing rate equal to FEU's weighted cost of capital would be appropriate. FEU would need to determine whether the $2,000 to $10,000 range would be appropriate given average customer contributions for gas extensions.

For smaller extensions, or as an option for large extensions, the addition of short-term, interest-free installment payments would also be appropriate. This option would be similar to that offered by Gaz Metro and Puget Sound Energy. Allowing equal installment payments over a 24-month period, with no interest charges, would be appropriate. Because of the construction period for main extensions and the regulatory lag between when an extension is completed and when it is placed in rate base, there is likely little or no cost to the utility for this 24-month period. The current policy is likely to generate many cases where the customer contribution is placed in rate base in one year while the capital cost is not included until the following year. With a 24-month installment plan the average payment period is one year from the application date, which would line up with the average time when the extension is added to rate base.

Financing would of course need to be subject to credit approval. Payments would also need to be paid in full prior to any transfer of ownership. With both of these financing options, customer contributions would be added to CIAC and placed in rate base as they are received.

Final Recommendation

The current MX test needs some adjustments to better align with other utilities and provide internal consistencies. We would recommend that the test period be extended and that the overhead factor be adjusted to be consistent with capitalized overhead amounts. These adjustments are necessary to provide consistency with FEU's accounting practices that have been approved by the Commission. We would also suggest that appliance usage amounts be standardized to reflect a long-term average use rather than one that is declining over time. This would provide greater equity between the amount of allowances provided to past customers and future customers. These adjustments are needed regardless of whether or not standard credits per appliance are adopted or not.

It is recommended that FEU adopt the standard credit per appliance approach for residential customers currently used in California and Oregon. This would allow for a more transparent policy for the customer, would allow for oversight of the calculations used to establish the credits that are available for all customers, and would simplify the process required for new customer connections. This approach would also eliminate the need for annual reporting of actual costs and benefits by project. As discussed above, these credits can be readily established using the currently approved MX test.

Finally, offering financing options for customer contributions is recommended. This could take the form of a 5-year loan at the weighted cost of capital for large projects, as is available for FortisBC electric customers. For small customers and as an option for large customers, a 24-month interest-free installment plan would be appropriate.

Attachment 188.1

Operation and Maintenance

Code of Accounts

May 2013

ACTIVITY-BASED VIEW

100 OPERATIONS

110 DISTRIBUTION

110-10 DISTRIBUTION - SUPERVISION
110-11 Distribution - Supervision

110-20 DISTRIBUTION OPERATIONS
110-21 Operation Centre
110-22 Distribution – Preventative Maintenance
110-23 Distribution - Operations
110-24 Distribution – Emergency Management
110-25 Distribution – Field Training
110-26 Distribution - Meter Exchange

110-30 DISTRIBUTION MAINTENANCE
110-31 Distribution - Corrective

110-40 DISTRIBUTION METER TO CASH
110-41 Distribution – Account Services
110-42 Distribution – Bad Debt Management

120 TRANSMISSION

120-10 TRANSMISSION - SUPERVISION
120-11 Transmission - Supervision

120-20 TRANSMISSION OPERATIONS
120-21 Pipeline/Right of Way Operations
120-22 Compression Operations
120-23 Measurement Control Operations

120-30 TRANSMISSION MAINTENANCE
120-31 Pipeline/Right of Way Maintenance
120-32 Compression Maintenance
120-33 Measurement Control Maintenance
130 LNG OPERATION

130-10 LNG PLANT OPERATIONS
130-11 LNG Plant Operations

130-20 LNG PLANT MAINTENANCE
130-21 LNG Plant Maintenance

200 CUSTOMER SERVICE

200-11 Customer Service - Supervision
200-12 Customer Assistance
200-13 Customer Billing
200-14 Meter Reading
200-15 Credit & Collections
200-16 Customer Operations

300 ENERGY SOLUTIONS & EXTERNAL RELATIONS

300-11 Energy Solutions & External Relations – Supervision
300-12 Energy Solutions
300-13 Energy Efficiency
300-14 Corporate Communications and External Relations
300-15 Resource Planning, Market and Business Development

400 BUSINESS SERVICES

410 ENERGY SUPPLY & RESOURCE DEVELOPMENT
410-11 Energy Supply & Resource Development
410-12 Gas Control

420 INFORMATION TECHNOLOGY
420-11 Information Technology - Supervision
420-12 Application Management
420-13 Infrastructure Management

430 ENGINEERING SERVICES & PROJECT MANAGEMENT
430-11 System Planning
430-12 Engineering
430-13 Project Management

440 OPERATIONS SUPPORT

440-11 Supply Chain
440-12 Measurement
440-13 Property Services

450 FACILITIES
450-11 Facilities Management

460 ENVIRONMENT HEALTH & SAFETY
460-11 Environment Health & Safety

500 CORPORATE SERVICES

510 FINANCIAL & REGULATORY SERVICES
510-11 Financial & Regulatory Services

520 HUMAN RESOURCES
520-11 Human Resources

530 GOVERNANCE
530-11 Legal
530-12 Internal Audit
530-13 Risk Management/Insurance

540 CORPORATE
540-11 Administration & General
540-12 Shared Services Agreement
540-16 Retiree Benefits

RESOURCE-BASED VIEW

1000 COMPENSATION CHARGED TO O&M

2000 EMPLOYEE EXPENSES

3000 VEHICLES

4000 MATERIALS AND SUPPLIES

5000 FEES AND ADMINISTRATION COSTS

6000 FACILITIES

7000 CONTRACTOR COSTS

8000 COMPUTER COSTS

9000 RECOVERIES AND REVENUES

ACTIVITY VIEW OF O&M REPORTING

100 OPERATIONS

110 DISTRIBUTION

110-10 DISTRIBUTION – SUPERVISION

110-11 Distribution - Supervision

Salaries, vehicles, equipment expense, materials, supplies and other expenses incurred in the general supervision and management of distribution operations. Includes expenses associated with:

- Directors/Regional Managers
- Operations Field Managers
- Field Operations Assistants (clerical staff in regional locations)
- Communications
- Claims Administration (to and from third parties)
- Service Award/Milestone Programs
- Conferences/Travel
- Damage Prevention
- Operations Reporting

110-20 DISTRIBUTION - OPERATIONS

110-21 Operations Centre

Salaries, vehicles, equipment expense, materials, supplies and other expenses for:

- Operations Centre Managers
- Process Management
- Emergency Support
- Resource Planning
- Scheduling and Dispatch
- Closing and Administration
- Installation Coordination (planning and design)

- Surveying
- Customer Appointment Setting

110-22 Distribution - Preventative Maintenance

Wages, vehicles, materials, contractors and other expenses associated with scheduled or routine field operational work and minor repairs as they relate to:

- stations, line heaters, meter-sets, meters, meter devices, bio-gas facilities, natural gas for vehicle (NGV) facilities and propane equipment

110-23 Distribution - Operations

Wages, vehicles, materials, contractors and other expenses associated with scheduled or routine field operational work as they relate to:

- valve inspections and minor valve repairs
- system leak surveys, primarily mains and services including residential, business, special use, special survey types (land slippage, audits, re-checks) , intermediate pressure assets.
- pre-paving surveys in advance of local municipal improvements
- any survey by request
- leak surveys on transmission pressure laterals (included in distribution plant)
- odorant operations including measuring/filling of bulk odorant facilities, inspection of odorizer facilities and equipment including measurement of product in storage, minor adjustments, calibrations and minor repairs, pipeline inspections including identification , resolution and prevention of activities that could endanger the pipeline
- activities to identify maintenance or system integrity concerns
- replacing line markers and warning signs
- vegetation management of pipeline right-of-ways/station facilities
- snow removal , utilities and painting at stations
- line locates
- distribution system risk assessments including bridge inspections
- line heater fuel
- winter pressure survey
- recording pressures and changing charts
- inspection of meters for ice or snow

110-24 Distribution - Emergency Management

Wages, vehicles, materials, contractors and other expenses associated with responding to emergencies including:

- gas odour calls
- carbon monoxide investigation calls
- fire, explosions and other customer safety calls
- first response standby during and after regular work hours
- restoring gas service to customers including relights to customer appliances and equipment
- system damage on mains, services, meters and stations, as a result of third parties, natural events, system failure and operator error.

110-25 Distribution – Field Training

Wages, vehicles, materials, contractors, course fees, travel and other expenses associated with formal IBEW training primarily for field activities.

- Includes the cost of those receiving the training as well as delivering the training. Training delivery can be through e-learning, internal instructor, peer trainer or external contractor.
- Excludes the cost of on the job training.
- Excludes the cost of Training department in design of courses, content management, training facilities.

110-26 Distribution – Meter Exchange

Wages, vehicles, materials, contractors, and other expenses associated with meter exchanges (residential to industrial).

- Changing time expired and in-date meters and instruments
- Resetting meters and meter-sets of the same class.
- Compliance sampling as directed by Measurement Canada.

110-30DISTRIBUTION - MAINTENANCE

110-31 Distribution - Corrective

Meters and Meter-sets

Costs related to:

- inches, instrument drives, and OFM meter-set overhauls which are determined during operational checks
- miscellaneous meter maintenance such as: raising, code violations, inspecting and testing meter-sets and alterations to bypass assemblies
- re-lighting a residential meter set after maintenance work completed when subsequent visit for relight is required.

Meter Devices

Costs related to:

- repairs to the automatic meter reading devices and electronic/control equipment
- troubleshooting and repairs on portable instruments used to evaluate or test system operations
- repairs and repair contracts for SCADA (Supervisory Control and Data Acquisition) - system that Gas Control uses to monitor, control and manage the transmission system

Valve Repairs

Costs related to:

- resetting or replacing valve boxes
- replacement of stem packing, o-rings, valve stops and road box height adjustment

Leak Repairs

Costs related to:

- gas leak locate and repair, including:
- valve leaks, on IP (intermediate pressure), DP (distribution pressure) or LP (low pressure) main
- service line leaks
- main leaks that are not repaired by cutting off and abandoning a section of unused main or by carrying out a renewal of main over 6 meters.

Station Repairs

Costs related to:

- station overhauls and repairs as well as repairs to associated buildings, structures, regulators, reliefs, valves, piping and related equipment.

General Maintenance

Costs related to:

- paving repairs
- main clearing operations
- maintaining main ditches, bell holes and other street cuts

Propane equipment repairs

Costs related to:

- the unscheduled repair of propane transfer, storage, regulation and vaporization equipment.

110-40 DISTRIBUTION - METER TO CASH

110-41 Distribution – Account Services

Wage and vehicle costs related to the following field activities:

- High bill investigations - investigate complaints due to high bills
- Meter identifications - identify/verify meter numbers corresponding to correct address and usage
- Meter investigations - investigate customer calls relating to a switch, stopped, non-registering or noisy meter.
- Meter re-reads

110-42 Distribution – Bad Debt Management

Wage, vehicle and contractor costs related to bad debt management field activities for all rate classes from residential to industrial:

- lock-offs
- reconnects
- re-lights.
- also includes revenues associated with bad debt management Revenues are recoveries collected on reconnection of service as specified in the tariff.

Includes costs incurred, net of recoveries, in conducting lock offs for arrears, vacant premises, seasonal, final reads and disconnect diversions to prevent unauthorized consumption, as well as “Cap and Plug” activities as per instruction from Gas Safety Branch or other agencies. Includes costs incurred to remove locks from locked off meters, vacant premises, seasonal, final reads and relighting appliances, during and after work hours.

120 TRANSMISSION

120-10TRANSMISSION - SUPERVISION

120-11 Supervision - Transmission

Salaries, vehicles, equipment expense, materials, supplies and other expenses incurred in the general supervision and management of Transmission and LNG Plant Operations.

120-20TRANSMISSION - OPERATION

120-21 Pipeline / Right of Way Operations

Costs incurred to manage planned maintenance of the lower mainland and interior pipeline transmission lines. Costs to manage all rights of way associated with transmission lines and to ensure that all transmission lines are clear of vegetation and are available for easy access.

Cost of planned maintenance activities, for mainline transmission operating plant assets including:

- development and maintenance of an integrity management plan
- asset assessments (data collection for in-line inspections, above-ground electrical surveys, natural hazards inspections, class location surveys, pipeline digs) to demonstrate and ensure asset integrity and for development of future asset assessment plans and/or asset improvement plans.

120-22 Compression Operations

Costs incurred to manage planned maintenance at compressor stations. Compressor stations in the interior include Savona, Armstrong, Kingsvale, Hedley, Midway, Warfield and Kitchener A and B compressor stations. The Langley compressor station is the only station in the lower mainland.

Includes the cost of company own-use gas as well as electricity expenses for the Hedley compressor station.

120-23 Measurement Control Operations

Costs related to scheduled instrumentation, communication services, and data acquisition such as:
Annual and recurring field maintenance checks performed on the Vancouver Island system for electronics including SCADA, telemetry, and RTUs

120-30TRANSMISSION MAINTENANCE

120-31 Pipeline / Right of Way Maintenance

Wages, vehicles, materials, contractors, travel and other expenses associated with corrective maintenance of the lower mainland and interior pipeline transmission lines.

This account includes all work done when a TP or IP pipeline is excavated for repair as a result of defect indications found during inspections (note 1) but excludes excavations where defects were neither indicated nor found (note 2).

Notes:
1. Include off-target digs where a subsequent dig located the indicated defect.
2. “Control digs” are required by the inspection protocol in the absence of defect indications and if confirmed “defect-free” are to be charged to the original inspection in account 120-21.

120-32 Compression Maintenance

Wages, vehicles, materials, contractors, and expenses associated with compressors, engines, and ancillary equipment such as valves, transmitters, switches and other such items that require repair or replacement.

120-33 Measurement Control Maintenance

Costs related to unscheduled instrumentation, communication services, and data acquisition such as:
Trouble-shooting, repairs and materials performed on the Vancouver Island system for electronics including SCADA, telemetry, RTUs.

130 LNG PLANT

130-10LNG PLANT OPERATION

130-11 LNG Plant Operation

Wages, vehicles, materials, contractors, and expenses associated with routine operation and planned maintenance of LNG facilities.

130-20LNG MAINTENANCE

130-21 LNG Maintenance

Wages, vehicles, materials, contractors, and expenses associated with unplanned corrective maintenance of LNG facilities.

200 CUSTOMER SERVICE

200-11 CUSTOMER SERVICE - SUPERVISION

Cost of labour, vehicles, travel, supplies and other expenses for the Vice President, Customer Service and administrative personnel supporting the Vice President.

200-12 CUSTOMER ASSISTANCE

Customer care services are comprised of the following services:

- Customer Contact - consists of contact services and costs of salaries and expenses related to emergency service call handling, billing inquiries, payment/billing program inquiries, customer move orders, customer complaints, customer education, gas service line and meter requests, interactive voice response for mass market customers, quality assurance, and work force management.
- Includes the services required to handle customer inquiries, customer enrolments, enrolment verification, and partial support for credit and collections.
- Also includes services rendered for the Construction Services Contact Centre and large volume customers.

200-13 CUSTOMER BILLING

- Billing Support - includes the services, and costs of salaries & expenses related to billing, payment processing, customer accounting, data interpretation and information requests, Industrial billing, and systems support for mass market customers.

200-14 METER READING

- Meter Services - includes the services related to meter reading, meter reading route management, meter order processing, high bill investigations, and meter identification for mass market customers.

200-15 CREDIT & COLLECTIONS

- Credit and Collections - includes collection management, credit approval, credit monitoring, security deposit monitoring, and administration of non-cash security for mass market customers.
- Costs associated with bad debt provision expense, Industrial bad debt, recoveries and collection agency commissions.

200-16 CUSTOMER OPERATIONS

- Customer Operational Services - includes the costs of salaries and expenses and services required to handle educational material, data capture and transfer of data related to market participation, financial reporting of marketer billings, marketer tariff set up and maintenance, and summary reporting related to the program.
- Includes costs incurred for market research conducted to assess the satisfaction of customers in order to improve all areas of service with the company
- Includes costs incurred to administer and improve customer service systems including the customer information system, customer portal, interactive voice response system, workforce management software and telephony system. Responsibilities include prioritization and testing of fixes and enhancements, defining business requirements for new software and hardware, and basic system configuration.

300 ENERGY SOLUTIONS AND EXTERNAL RELATIONS

300-11 ENERGY SOLUTIONS & EXTERNAL RELATIONS - SUPERVISION

Cost of labour expenses incurred in the general supervision and strategic direction for the Energy Solutions and External Relations business unit.

300-12 ENERGY SOLUTIONS

Cost of labour and expenses related to account management including one-on-one management of large key account customers, energy use consultation and new tariff code development.
The cost of labour and expenses incurred to provide the following activities:

- Identify and implement activities to add new customers and load
- individual key account management/liaison (including credit and collections)
- print, supply/distribute technical literature, data sheets, brochures and newsletters
- energy use case studies and site visits
- annual transportation contracts
- sales of company products and services to existing and new customers
- Builder, developer and industry liaison
- Provide technical advice on gas use to customers

300-13 ENERGY EFFICIENCY

Costs incurred, including incentive payments, for the execution of Energy Efficiency and Conservation ("EEC") programs that are not captured in Demand Side Management ("DSM") deferral accounts. For example, Switch and Shrink Program.

300-14 CORPORATE COMMUNICATIONS, MARKETING and PUBLIC AFFAIRS

Costs incurred in managing and orchestrating management, marketing and organizational communications with both internal and external stakeholders.

This includes the following costs:

- Safety education messaging
- Media monitoring
- Web communication and monitoring
- Paid media design and production
- Employee communications
- Customer newsletters
- Writing and editing services
- Crisis communication
- Social media

Cost of labour and expenses incurred for maintaining ongoing relationships with communities, municipalities, key government ministries, local First Nations and business associations.

300-15 FORECASTING, MARKET and BUSINESS DEVELOPMENT

Cost of labour and expenses incurred to identify and develop new energy service products and initiatives, new business opportunities and to forecast short term and long term customer energy demand.

This includes costs to perform the following activities:

- forecast gas load, customer additions, and revenue
- investigate and develop service enhancements and new tariff options for customers
- develop company's long term resource plan
- identify and develop new business opportunities and energy service offerings
- monitor and assess gas technology and regulation developments

400 BUSINESS SERVICES

410 ENERGY SUPPLY & RESOURCE DEVELOPMENT

410-11 ENERGY SUPPLY & RESOURCE DEVELOPMENT

Includes costs incurred for:
- management of transportation and marketing services on the pipeline system,
- oversight on-system gas transportation and industrial, commercial, and marketer agent services,
- providing gas supply infrastructure planning'
- management of major capacity and sustainment initiatives,
- identifying and developing new regional projects as well as system infrastructure projects within the Company's current service areas, including pipeline, compressor, and storage projects.

410-12 GAS CONTROL

Costs associated with dispatching and operating the gas transmission and distribution system in a manner to meet the corporate obligation of safe, dependable and economical gas service to customers. Gas Control is a 24/7 operation and is responsible for the continuous monitoring and operation of the pipeline to meet customers energy, pressure and gas quality requirements with maximum dependability. In addition, Gas Control performs the daily system load forecasts, as well as short-term 5-day forecasts for gas commodity purchasing.

Costs associated with planned maintenance around monitoring and/or controlling:

- the flow of gas in the system
- the odorization system
- the operation of the compressor, regulator and valve stations in the system
- the operation of the line heaters in the system
- pressure in the system
- flow imbalances

Includes costs related to monitoring the security system, responding to alarm conditions, preparing gas load requirements, maintaining the SCADA system and adding and deleting points to SCADA.

420 INFORMATION TECHNOLOGY

420-11 INFORMATION TECHNOLOGY – SUPERVISION

Cost of labour, travel, office supplies, and other expenses incurred in the general supervision of information technology. Includes:

- costs for planning and development of technology and business system initiatives (OPEX),
- costs of training for new Applications.

420-12 APPLICATION MANAGEMENT

Costs for the overall data and application architecture, including, but not limited to:

- SAP enterprise application, including all customer service components
- Click scheduling application
- CAFÉ (Customer Attachment Front-End) application. CAFÉ includes process enhancements from customer attraction through order completion to collect, sort,

prioritize, assign and measure company performance in closing leads and enable improved customer order processing currently handled in SAP.

- Measurement related applications such as MACS (Measurement Application Computer System) which supports the Meter Shop business processes primarily capturing measurement equipment data that is interfaced to SAP.
- AM/FM (Automated Mapping / Facilities Management) and DCRS (Digitized Construction Records System)
- Forecasting Information System
- WIN Gas Connect – “Web Interface Nomination” System
- middleware, a toolset that facilitates the integration of data between applications
- Business Intelligence applications such as Business Warehouse (BW)
- Intranet and Internet.

420-13 INFRASTRUCTURE MANAGEMENT

Cost of managing the overall technology environment and infrastructure architecture including, but not limited to:

- maintaining communication sites and overseeing radio site rentals
- security and virus protection
- network costs
- LAN (local area network) and WAN (wide area network
- server services
- server hardware and software costs
- maintenance of peripheral devices such as desktops, laptops and printers
- Peripheral related software such as operating systems, Microsoft Office, etc.
- application services such as e-mail and Citrix.

430 ENGINEERING SERVICES & PROJECT MANAGEMENT

430-11System Planning

Cost of labour and expenses for a number of departments responsible for planning and maintaining the gas system (transmission and distribution) assets. These departments are responsible for short and long-term capacity planning, for identifying and justifying necessary system upgrades and/or replacements to ensure the integrity gas assets and for development of preventative maintenance plans.

430-12 Engineering

Cost of labour and expenses for a number of departments responsible for the design and drafting of new or replacement gas system assets. This includes technical specialists such as the GIS and asset data management groups, integrity management and reliability assessment groups, corrosion and geo-technical groups, and front-end engineering design (FEED) and estimating groups. This area is responsible for assisting the System Planning groups in project justification and for translating the plans produced by the System Planning into constructible projects.

430-13 Project Management

Cost of labour and expenses for a number of departments responsible for the construction of new and upgraded gas system assets. This includes technical specialists such as project managers, project schedulers and financial analysts who are tasked with ensuring the successful execution of projects produced by the System Planning, Engineering, and Business Development areas.

440 OPERATIONS SUPPORT

440-11 SUPPLY CHAIN

Cost of labor and expenses incurred in support of supply chain activity. Supply chain refers to the combined functions of procurement, manufacturing and logistics.

<u>Procurement</u>
The procurement function relates to the sourcing and procurement of materials and services including tender development, contract maintenance, purchase order processing and vendor management.

<u>Manufacturing</u>
The manufacturing function is comprised of three separate areas including: machining and drill out work, welding and prefabrication of meter sets. A description of these areas is provided below:

- The Machine Shop is responsible for the maintenance and manufacturing of specialized tools used by FortisBC field employees or contractors. The group also provides “drill out” service for the installation of mains and service lines and emergency response within the coastal region.

- The Weld Shop is responsible for welding various meter set configurations used for residential, commercial and industrial applications as well as welds on mains construction in the field. The Weld Shop also provides emergency response service within the coastal region.

- The Prefabrication Shop is responsible for the final assembly and painting of the components made by the Weld Shop.

Logistics
Logistics relates to shipping and warehousing of approved field materials. Shipping involves the delivery of all materials to either the muster stations or directly to the job sites using company owned trucks or contracted delivery services. Alternatively, warehousing refers to the management of field material inventory as well as the handling new and recalled meter shipments within the service territory.

440-12 MEASUREMENT SERVICES

Cost of labor and expenses incurred in the performance of measurement services. Measurement services includes the specific functions of meter fleet management, meter testing, meter repair and field data collection.

Fleet Management
The meter fleet management is characterized by the following work:

- Performance evaluation, planning and budgeting for maintenance and capital activities associated with the meter fleet in accordance with the Measurement Canada compliance sampling program;
- Administrative and technical work associated with maintaining the Measurement Canada accreditation program;
- Service coordination for 3rd party measurement services.

Meter Testing & Repair
The meter testing and repair function relates to planned work involving:

- Meter testing and repair of meters in accordance with Measurement Canada requirements;
- Testing and repair of 3rd party meters.

Field Data Collection

The field data collection function refers the maintenance of data and voice communications equipment within the field including:

- Maintenance of measurement and data communication equipment within the coastal region at industrial customers sites and FortisBC operating sites;
- Maintenance of mobile radio repeater sites across the service territory;
- Processing of measurement data from industrial customer sites for billing purposes;
- Planned portable instrument maintenance activities.

440-13 PROPERTY SERVICES

The property services activity relates to the management of all land rights and land tenure issues including:

- Property taxation forecasting and payment;
- Fee simple and right of way acquisition to support new customer connections;
- Managing and enforcing property rights for continuous safe service delivery;
- Manage 3rd party access to and crossing of high pressure pipelines.

450 FACILITIES MANAGEMENT

450-11 FACILITIES MANAGEMENT

Labor and expenses incurred for the management of various facilities, including:

- maintenance of coastal buildings
- renting, operating and maintaining interior buildings
- labour and other expenses incurred in the general supervision and direction of the Facilities group
- telecommunications management
- rental and storage of office furniture and files
- maintenance of office equipment (lower mainland and interior offices)
- mailroom/reception
- printer consumables – toners/papers
- courier and postage costs
- centralized office supplies in the Surrey mailroom

460 ENVIRONMENT, HEALTH & SAFETY

460-11 ENVIRONMENT, HEALTH & SAFETY

Cost of labour and other expenses incurred in providing environmental and occupational health and safety governance, carrying out public and corporate safety activities, and emergency planning.

Includes costs related to:

- monitoring Workers' Compensation Board ("WSBC") regulatory changes and potential impacts on FortisBC's safety, environmental , security and emergency management systems;
- providing guidance and direction to the organization on WSBC regulatory requirements including, inspections, reports and reviews of compliance
- liaising with industry associations and other health and safety stakeholder groups on behalf of FortisBC
- liaising with industry associations and other environmental stakeholder groups on behalf of FortisBC, ensuring exposure control planning and assessment services for employees
- maintaining health and safety information system to record and track all workplace safety, environmental, or security related incidents and all employee injury information
- providing Occupational Health and Safety (OHS) and Environmental reporting information in order to meet internal and external reporting requirements
- conducting incident investigations as required
- acting as an EHS resource to all field personnel
- ensuring there is public awareness with regard to public safety issues
- liaising with agencies and the community to increase awareness with regard to public safety
- public safety communication and initiatives
- planning and preparing for and recovering from emergencies
- security issues, software development and supplies
- ensuring business groups maintain and practice emergency drills and that corporate plans are maintained
- designing and managing emergency exercises and ensuring corrective action plans are completed
- liaising with and developing relationships with governmental agencies and other related organizations
- ensuring mutual aid agreements are in place and maintained

500 CORPORATE SERVICES

510 FINANCIAL & REGULATORY SERVICES

510-11 FINANCIAL & REGULATORY SERVICES

Cost of labour, travel, supplies and other expenses incurred in providing the following services:

Finance

- financial accounting, including rate regulated accounting
- asset accounting
- internal and external reporting, including filing of the BCUC Annual Reports
- budgeting and planning, including monthly, quarterly, annual and long term forecasts, and cost of service forecasts in support of regulatory filings
- accounts payable

Regulatory

- development of regulatory plans in support of current and prospective regulatory issues
- assisting the operating groups with regulatory process, regulatory and industry research, and analytical support for projects and initiatives
- developing rate design (rate pricing) structures that are in alignment with cost structures
- managing each utility gas tariff related to applications for changes and new initiatives and ensuring implementation of rate changes
- managing regulatory relationships with the Commission and stakeholders
- managing compliance with Regulations, Orders, Directives, and Decisions

Taxation - providing a full range of services in income and commodity taxation including: financial reporting for taxes, tax compliance, regulatory tax accounting, tax planning, and tax dispute management and resolution

Treasury - services including: cash management and forecasting, arranging operating credit facilities and negotiating bank service fees, executing short and long term debt financing, implementing treasury related controls and compliance, including compliance reporting, managing rating agency, bank, and debt investor relationships, and providing credit and counter party credit risk management

This account also includes items such as external audit fees, rating agency fees, bank charges, and the BCUC Assessment Fee.

520 HUMAN RESOURCES

520-11 HUMAN RESOURCES

Cost of labour and other expenses for administering compensation programs, labour relations, pensions and benefits, employee advisory services, employee training and development, payroll, employee data and recruiting.

530 GOVERNANCE

530-11 LEGAL

Cost of labour and other expenses for providing legal services and counsel on issues including regulatory, environmental, business development, employment, securities, financing, and intellectual property, and managing legal matters that have been outsourced to outside legal counsel.

530-12 INTERNAL AUDIT

Cost of labour and other expenses for developing, planning and conducting audits/reviews, conducting annual risk assessment processes, monitoring and evaluating the effectiveness and efficiency of internal controls.

530-13 RISK MANAGEMENT/INSURANCE

Cost of labour and other expenses for ensuring compliance with the TSX requirements on risk management, arranging for coverage based on assessed potential risk, and ensuring an appropriate and prudent insurance program

This account also includes the cost of insurance coverage.

.

540 CORPORATE

540-11 ADMINISTRATION & GENERAL

The expenses in this account include:

- salary, travel and other expenses for the President
- compensation, travel and other expenses for the Board of Directors

-
- other administrative/general costs not otherwise defined in the code of accounts

540-12 SHARED SERVICES AGREEMENT

This account includes:

- management fees paid for services provided by Fortis Inc. or any of the Fortis utilities
- management fee received from any of the Fortis utilities for services provided by the affiliated utility

540-16 RETIREE BENEFITS (in use to end of 2013)

This account includes the actuarial cost of providing pension and other post-employment benefits to retirees

RESOURCE VIEW

1000 Compensation Charged to Operations and Maintenance ("O&M")

This account includes the O&M component of the cost of labour and benefits for all three affiliations (M&E, COPE and IBEW), including other retiree benefits as defined in account 540-16.

2000 Employee Expenses

This account includes cost such as:

- course fees
- travel and meals and entertainment (training and non-training related)
- mileage allowance
- employee hiring and relocation costs

3000 Vehicles

This account includes the costs associated with vehicles and other types of equipment including:

- vehicle and equipment rentals
- lease charges and operating costs
- license fees
- fuel expense
- repairs and maintenance

4000 Materials and Supplies

This account includes costs related to:

- personal supplies (e.g. purchase and cleaning of uniforms, shoes, gloves, hard hats, etc.)
- costs associated with the purchase, rent, and lease of office furniture as well as any required repairs and maintenance
- office supplies

- miscellaneous field, shop, road, surfacing and backfill materials (used in O&M work)
- inventory write-downs/revaluations, shrinkage/adjustments and other material adjustments
- freight charges

5000 Fees and Administration Costs

This account includes costs such as:

- government fees
- membership dues
- BCUC assessments
- external auditor fees
- legal fees and retainers including land acquisition fees
- continuing/shared services
- charitable donations, political contributions and corporate sponsorships
- easement and rights-of-way fees and costs
- communications – investor, public relations and employees
- advertising – e.g. media, printed matter
- administration – e.g. postage, couriers, contracts and outside services
- damages and injury costs
- insurance
- bad debt expense
- bank charges

6000 Facilities

This account includes costs related to:

- communication
- heat and light
- company own-use gas
- electrical maintenance on buildings, exterior lighting
- heating, ventilation and air conditioning (HVAC)
- janitorial services
- landscaping
- plumbing

- garbage removal and recycling
- security
- snow removal
- window cleaning
- yard maintenance
- building maintenance.

7000 Contractor Costs

This account includes costs related to:

- consulting fees
- contractors
- customer care services (ABSU)

8000 Computer Costs

This account includes costs related to:

- computer consulting
- outsourced computer services
- hardware and software not meeting capitalization criteria

9000 Recoveries and Revenues

This account includes the following recoveries/revenues:

- recovery of bad debt previously written off
- amounts received as recoveries from salvaged materials
- recoveries of O&M costs - miscellaneous recoveries not undertaken with an expectation of profit (e.g. lease recoveries, sales of miscellaneous O&M materials at cost)
- recovery of direct costs and overhead incurred on behalf of non-regulated businesses
- management fees received (as described in account 900-14)

Attachment 201.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 203.5.1

Effective: OCT 16 1997 L-64-1997

BCUC Secretary: *Original signed by R.J. Pellatt*

[FortisBC Energy Inc.]

C O D E O F C O N D U C T

For Provision of Utility Resources and Services
August 1997

SCOPE

This Code of Conduct (Code) governs the relationships between [FortisBC Energy Inc. (FortisBC Energy)] and Non-Regulated Businesses (NRBs) for the provision of Utility resources, and conforms with the British Columbia Utilities Commission (Commission) "Retail Markets Downstream of the Utility Meter" (RMDM) Guidelines of April, 1997. The Commission Code of Conduct Principles from the Guidelines are attached as Appendix 'A'.

This Code will govern the use of Utility resources for unregulated activities (products or services for which there are no Commission approved tariffs) including shared services, employment or contracting of Utility personnel, and the treatment of customer, utility, or confidential information. The Code will also determine the nature of the relationship between the Utility and NRBs and the treatment by the Utility of its' NRBs.

The primary responsibility for administering this Code lies with [FortisBC Energy], although the Commission has jurisdiction over matters referred to in this Code. The Commission acknowledges that the Utility in the administration of the Code may have to take into account particular circumstances in respect to a particular product or service which is being provided or transferred out of the Utility, and where these issues are at variance with this Code Commission approval will be required. The Code also provides that the Commission may review complaints in relation to the Code.

The [FortisBC Energy] Transfer Pricing Policy, dated August 1997, will be used in conjunction with this Code to establish the costs and pricing for Utility resources and services.

This Code supersedes and replaces the [FortisBC Energy] Code of Business Conduct dated March 31, 1995. However, this Code does not replace contracts and undertakings between [FortisBC Energy] and NRB affiliates in existence prior to approval of the Code.

Definitions

[FortisBC Energy Inc.]	*May be abbreviated as follows: [FortisBC Energy], the Utility, or the Company, and may also include employees of the Company.*
Commission	*British Columbia Utilities Commission.*
Guidelines	*Retail Markets Downstream of the Utility Meter Guidelines published by the British Columbia Utility Commission in April, 1997.*
Non-Regulated Business (NRB)	*An affiliate of the Utility not regulated by the Commission or a division of the Utility offering unregulated products and services. "Related NRB" refers to any NRB which is an affiliate of the Utility and which uses any resources of the Utility.*
Ratepayers	*Ratepayers in most cases are considered as a whole rather than one group or rate class.*
RMDM	*Acronym for "Retail Markets Downstream of the Utility Meter", which may include any utility or energy related activity at or downstream of the utility meter.*
Transfer Pricing	*The price established for the provision of Utility resources and services, or the transfer of Utility assets, to an NRB or division of the Utility providing unregulated products and services. Transfer pricing for any Utility resource or service will be determined by applying the [FortisBC Energy] Transfer Pricing Policy approved by the Commission.*

APPLICATION OF COMMISSION PRINCIPLES

1. Transfer Pricing

The Utility will conform with the Commission approved [FortisBC Energy] Transfer Pricing Policy.

2. Shared Services and Personnel

a) This Code recognizes the need for and potential benefits to the Utility of employee transfers and human resource sharing.

b) [FortisBC Energy] may provide shared services to NRBs, including supervision and management, while ensuring that ratepayers will not generally be negatively impacted by Utility involvement. The costs of providing such services will be as agreed upon by both parties and be in accordance with the Commission approved [FortisBC Energy] Transfer Pricing Policy.

c) NRBs may contract for any Utility personnel using the Commission approved [FortisBC Energy] Transfer Pricing Policy, providing the Utility complies with Section 4 of this Code, Provision of Information by [FortisBC Energy Inc.], and no conflict of interest exists which will negatively impact on ratepayers.

3. Transfer of Assets or Services

The price for all transfers of assets or services shall be determined in accordance with the [FortisBC Energy] Transfer Pricing Policy approved by the Commission, and the Utility must be able to demonstrate that the benefits to the ratepayer are greater than the cost. The transfer price will reflect the potential for risk (stranded assets, future costs, etc.) and the recall availability of shared or transferred personnel to ensure the Utility receives the appropriate benefit from expertise resident in the Utility. [FortisBC Energy] will comply with acceptable business practices if it wishes to purchase assets, goods or services from an NRB.

An appropriate allocation of development costs for products or services as defined in the [FortisBC Energy] Transfer Pricing Policy, will be included in the transfer price.

4. Provision of Information by [FortisBC Energy Inc.]

[FortisBC Energy] will not provide to an NRB any information that would inhibit a competitive energy services market from functioning.

The following should act as a guideline for employees confronted with issues related to the sharing of confidential information:

a) This Code precludes [FortisBC Energy] from releasing confidential customer specific information without the consent of that customer. If a customer agrees to a general release of customer specific information, that information must be made available to any market participant who requests it and is willing to pay costs associated with the provision of the information, without discrimination as to access, timing, cost or content. If a customer requests customer specific information be provided to a specific market participant, only that participant may receive the information, subject to payment of associated costs incurred to provide the information.

b) [FortisBC Energy] may disclose to any market participant that requests it and is willing to pay the appropriate transfer price customer information that is aggregated or summarized in such a way that confidential information would not ordinarily be ascertained by third parties.

c) [FortisBC Energy] may provide or sell any non-customer specific information to any market participant that requests it and is willing to pay the appropriate transfer price.

5. Preferential Treatment

[FortisBC Energy] will not state or imply that favoured treatment will be available to customers of the Utility as a result of using any service of an NRB. In addition, no Company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the Company as a result of using any product or service of an NRB.

6. Equitable Access to Services

Except as required to meet acceptable quality and performance standards, and except for some specific assets or services which require special consideration as approved by the Commission, [FortisBC Energy] will not preferentially direct customers seeking competitively offered services to an NRB or a specific retailer.

7. Compliance and Complaints

a) [FortisBC Energy] will advise all of its employees of their expected conduct pertaining to this Code, with annual updates for employees who may be directly involved with NRB activities.

b) [FortisBC Energy] will monitor employee compliance with this Code by conducting an annual compliance review, the results of which will be summarized in a report to be filed with the Commission within 60 days of the completion of this review.

c) Complaints by third parties about the application of this Code, or any alleged breach thereof, should be addressed in writing to the Company's [Executive Vice-President, Finance, Regulatory and Energy Supply], who will bring the matter to the immediate attention of the Company's senior management and promptly initiate an investigation into the complaint. The complainant, along with the Commission, will be notified in writing of the results of the investigation, including a description of any course of action which will be or has been taken promptly following the completion of the investigation. The Company will endeavour to complete this investigation within 30 days of the receipt of the complaint.

d) Where [FortisBC Energy] determines that the complaint is unfounded, the Company may apply to the Commission for reimbursement of the costs of the investigation from the third party initiating the complaint or where this is not possible, for inclusion of those costs in rates.

8. Financing and Other Risks

[FortisBC Energy] will not undertake any financing or other financial assistance on behalf of an NRB that exposes utility ratepayers to additional costs or risks, unless appropriate compensation is received by [FortisBC Energy] for such financing or other financial assistance, and such financing or other financial assistance is approved by the Commission.

9. Use of Utility Name

[FortisBC Energy Inc.] agrees that newly established NRBs engaging in RMDM activities will not use the Utility's name as the primary identifier within British Columbia, and will not use the Utility name in a manner that indicates that Utility resources will support the NRB.

10. Distribution System Access

[FortisBC Energy] will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and in accordance with the requirements approved for direct commodity marketing in British Columbia.

11. Amendments

In order to ensure that this Code remains workable and effective, the Company will review the provisions of this Code on an ongoing basis and as required by the Commission, but with a maximum of three years between reviews.

Amendments to this Code may be made from time to time as approved by the Commission.

Appendix 'A'

COMMISSION CODE OF CONDUCT PRINCIPLES

The Commission has established the following principles in the Guidelines which [FortisBC Energy] intends to apply to RMDM activities and the Utility's relationships with NRBs.

i) The regulated company will not provide to the NRB any market-sensitive or confidential information that would inhibit a competitive energy services market from functioning. If customers agree to a release of customer information to the NRB, it should be provided to other market participants under the same terms and conditions and for the same price. Should an individual customer make a specific request to have information released to a particular third party, it will be released to that party only. The utility will be able to recover from the customer the costs associated with the provision of this information.

ii) No regulated company personnel will state or imply that favoured treatment will be available to customers of the company as a result of using any service of an NRB. In addition, no regulated company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the company as a result of using any service of an NRB.

iii) No regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB. If a customer, or potential customer, requests from the regulated company information about products or services offered by an NRB or its competitors in downstream markets, the regulated company may provide such information, including a directory of retailers of the product or service, but shall not promote any specific retailer in preference to any other retailer.

iv) The regulated company will formally advise all employees of expected conduct related to these principles and it will undertake to perform periodic audits of the relationships to ensure compliance with these principles. These audits will be performed no less than once a calendar year and filed with the Commission.

v) Complaints by non-affiliated parties about the application of these principles, or any alleged breach thereof, will be brought to the immediate attention of the senior management of the regulated company and subsequently a report of the complaints, and action taken, will be filed with the Commission. The report will be filed with the Commission within one month of the complaint being made.

vi) The financing of the utility and NRB will be accounted for entirely separately with the financing costs reflecting the risk profile of each entity. No cross-guarantees or any form of financial assistance whatsoever should be provided directly or indirectly by a utility to its NRB without approval of the Commission.

vii) Use of the utility name by a related NRB will require approval by the Commission to ensure that its use will not interfere with the Commission's ability to protect ratepayers.

In those cases where retail customers have direct market access to the commodity, the utility's code of conduct will also include the following provision,

> The regulated company will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and according to the requirements approved for direct commodity marketing in British Columbia.

Effective: OCT 16 1997 L-64-1997
BCUC Secretary: *Original signed by R.J. Pellatt*

[FortisBC Energy Inc.]

TRANSFER PRICING POLICY

For Provision of Utility Resources and Services
August 1997

SCOPE

This policy addresses the pricing of resources and services provided by [FortisBC Energy Inc. (FortisBC Energy)] to:

- Non-Regulated Businesses (NRBs); and
- Divisions of the Utility providing unregulated products or services (collectively NRBs).

[FortisBC Energy Inc.] will ensure that it receives adequate compensation for the resources and services provided, thereby protecting ratepayers from subsidising unregulated activities.

The Transfer Pricing Policy will be used in conjunction with the [FortisBC Energy Inc.] Code of Conduct for Provision of Utility Resources and Services dated August, 1997. However, this policy does not replace [FortisBC Energy]/NRB contracts and undertakings in existence prior to approval of this Transfer Pricing Policy.

DEFINITIONS

[FortisBC Energy Inc.]	*May be abbreviated as follows: [FortisBC Energy], the Utility, or the Company, and may also include employees of the Company.*
Commission	*British Columbia Utilities Commission.*
Competitive Market Price (or Market Value)	*The price that would be paid for a resource or service in a fully functioning, competitive (unregulated) market. Alternatively, the prices of goods or services that can serve as substitutes for the resources or services being offered may also be used.*
Development	*The translation of research findings or other knowledge into a plan or design for new or substantially improved materials, devices, products, processes, systems or services prior to the commencement of commercial production or use.*
Guidelines	*Retail Markets Downstream of the Utility Meter Guidelines published by the British Columbia Utilities Commission in April, 1997.*
Non-Regulated Business (NRB)	*An affiliate of the Utility not regulated by the Commission or a division of the Utility offering unregulated products or services. "Related NRB" refers to any NRB which uses any resources of the Utility.*
Research	*Planned investigation undertaken for the purpose and expectation of gaining new scientific or technical knowledge and understanding. Such investigation may or may not be directed towards a specific practical aim or commercial application.*
RMDM	*Acronym for "Retail Markets Downstream of the Utility Meter", which may include any utility or energy related activity at or downstream of the utility meter.*
Transfer Price	*The price established for the provision of Utility resources and services, or the transfer of Utility assets, to an NRB or division of the Utility providing unregulated products and services. Transfer pricing for any Utility resource or service will be determined by applying the [FortisBC Energy] Transfer Pricing Policy approved by the Commission.*

<u>POLICY</u>

Transfer Prices charged to NRBs by the Utility will ensure Utility ratepayers are not adversely affected and will be established using the following pricing rules.

1. <u>Pricing Rules</u>

i. If an applicable [FortisBC Energy] tariff rate exists, the Transfer Price will be set according to the tariff.

ii. Where no tariff rate exists, the Transfer Price will be set at either the full cost (see Section 2 below) or, where feasible and practical, the Competitive Market Price, whichever is greater.

iii. In situations where it can be shown that an alternative Transfer Price will provide greater benefits to the ratepayer, the Utility may apply to the Commission for special pricing consideration.

2. <u>Determining Full Costs</u>

For the purposes of this policy, costs for the resources or services being provided by the Utility to an NRB will be based on the Utility's full cost as described below. The definition of full costs will depend on the type of service or resource being provided.

For the most part the types of resources and services that can be provided to NRBs by the Utility are human resources and associated equipment and facilities. The example in Appendix A summarizes how full costs are determined for the different types of services described below in Section 2.1. The determination of full costs, specifically the cost loadings, is based on the approved Code of Business Conduct with respect to Non-Regulated Businesses of [FortisBC Energy] dated March 31, 1995, with modifications reflecting the types of resources and services involved in RMDM.

If other Utility resources or services are used by an NRB that are not described by this policy, then* [FortisBC Energy] *will make an application to the Commission on a case-by-case basis. An example of this would be the determination of costs for a Utility asset permanently transferred to an NRB.

2.1 Type of Service

There are three types of services: Specific Committed Service, As Required Service and Designated Subsidiary/Affiliate Service. It is important that the type of service is specified before the commencement of any service. This specification is to ensure that the correct cost loadings are applied to any Transfer Price.

i. **Specific Committed Service**

Specific Committed Service is work that is contracted for and billed regardless of whether or not work is actually performed. Typically, this work is ongoing or on a continuing basis (such as accounting) in support of NRB activities. The receiving organization (i.e. the NRB) is, in effect, requiring that the providing organization's department (i.e. [FortisBC Energy]) maintain sufficient staffing levels throughout the year in order to provide this service. The receiving organization must pay for the Specific Committed Service even if the service provided is less than originally contracted.

It is important that the description and scope of the service to be provided be defined before the commencement of such a service, including an indication whether the service is performed at the employee's normal place of work ("on-site") or at the NRB's ("off-site"). A request for Specific Committed Service may be raised or terminated at any time throughout the year. Termination of a Specific Committed Service as a result of an activity change is subject to a sixty (60) day notice period.

At the end of the fiscal year, Specific Committed Services which were not provided (unless the Utility was unable to meet its commitments) will be offset against services used in excess of those committed. Any excess service on a total pooled basis will be billed, but any deficiency will not be refunded. If there is a shortfall in the level of service provided by [FortisBC Energy] a reasonable refund may be made. In the normal course of business, the time estimates for Specific Committed Service are reviewed annually.

To determine the full cost of Specific Committed Service, the following loadings are applied to direct labour costs: concessions loading, benefits loading and general overhead loading. Also facility and/or equipment charges are made if applicable. Appendix A, Column 1 shows an example of determining full cost for Specific Committed Service, both "on-site" and "off-site".

ii. **As Required Service**

As Required Service is work that is not specifically committed to by the receiving organization. The providing organization charges the cost of the actual time incurred to perform the work to the receiving organization. Typically, this is work that is not or cannot be budgeted in advance.

As Required Service must be specified to be either for an extended term (greater or equal to three months) or short term (less than three months) period prior to the commencement of the work. In addition, it must be identified whether the individual providing the services will work at his or her normal place of work ("on-site") or at the NRB's ("off-site").

To determine the full cost of As Required Service, the following loadings are applied to direct labour costs: concessions loading, benefits loading, general overhead loading, supervision loading and an availability charge loading. Also facility and/or equipment charges are made if applicable. Appendix A, Column 2 shows an example of determining full cost for As Required Service.

In certain situations, the Utility will need to retain the immediate right to recall the employee being contracted to the NRB for an As Required Service. In these situations the availability charge will be waived. Prior notification to the Commission is required to waive the availability charge for As Required Service.

iii. **Designated Subsidiary/Affiliate Service**

A Designated Subsidiary/Affiliate is a related company that is designated by [FortisBC Energy] and approved by the Commission to receive reduced loadings in the Transfer Price. The designation relates to the additional benefits that the related company provides to [FortisBC Energy]'s customers, employees or to the economic development of the Province of British Columbia.

A Designated Subsidiary/Affiliate receives services on the same basis as the As Required Service described above. To determine the full cost of Designated Subsidiary/Affiliate Service, the following loadings are applied to direct labour costs: concessions loading, benefits loading and a general overhead loading. Appendix A, Column 3 shows an example of determining full cost for A Designated Subsidiary/Affiliate Service.

The Commission may approve a subsidiary or affiliate with this status but exclude specific activities or projects of that subsidiary (e.g. projects taking place in certain geographic locations). Similarly, certain work to be performed for an NRB relating to a specific service, project or product may be designated by [FortisBC Energy] and approved by the Commission to receive reduced loadings.

3. <u>Costs Relating to the Transfer of Activities from the Utility to NRB</u>

3.1 Transfer Costs

Activities initially undertaken within the regulated Utility may, from time to time, be transferred to an NRB with Commission approval. Costs associated with transferring an activity to an NRB, and the start-up of NRB activities, shall be borne by the NRB. To the extent that these activities involve Utility resources during the transfer, the NRB shall reimburse the Utility using the appropriate pricing rules as defined in Section 1. Costs relating to the termination of an activity within the Utility shall be borne by the Utility.

3.2 Research Costs

As research is regarded as a continuing activity required to maintain the Utility's business and its effectiveness, such expenses shall be borne by the Utility. However, where it is evident that certain research activities are clearly directed towards specific non-regulated pursuits, the Utility will ensure it is compensated by the NRB according to the pricing rules defined in Section 1, net of any quantifiable benefits received by the Utility.

3.3 Development Costs

Development costs for new products and services transferred to an NRB will be tracked and charged to the NRB according to the pricing rules defined in Section 1, net of any quantifiable benefits received by the Utility.

4. Employment Issues

This section provides the guidelines which [FortisBC Energy] will follow in addressing the issues of employee transfers and human resource sharing between the Utility and NRBs. These guidelines implicitly recognize the fact that Utility ratepayers can realize significant benefits when employees have the opportunity to work for NRBs, by providing Utility employees with opportunities to expand their breadth of experience, enhance their skills and attributes, and continue their career development by taking advantage of the diversity of the [FortisBC Holdings Inc.] organization.

Accordingly, it is not the intent of these guidelines to restrict employee transfers or human resource sharing, but rather to ensure that the benefits gained by employees can be brought back to the Utility and realized by ratepayers, and ratepayers are not negatively impacted. In all cases of Utility employee transfers or human resource sharing, the terms of transfers or sharing must be clearly understood by the Utility, NRB and the employee prior to commencement, and properly documented.

These guidelines distinguish between three distinct types of human resource issues: Rotational Transfers, Non-Rotational Transfers and Human Resource Sharing.

4.1 Rotational Transfers

Rotational Transfers represent a career training and development vehicle, in which employees are transferred between the Utility and an NRB on a full-time basis, for a period of time not to exceed 3 years. In these instances, the salary and associated benefits of the employee in question will be assumed by the NRB for the duration of the rotational transfer period. As this initiative is specifically intended as a career training and development mechanism with expected benefits back to the Utility, the individual will typically be assured of continued employment by the Utility at the conclusion of the transfer period.

4.2 Non-Rotational Transfers

Non-Rotational Transfers represent transfers of personnel between the Utility and an NRB, which are not subject to a maximum time duration. As neither the Utility nor its NRBs are required to provide preference to the other's employees in filling permanent positions, non-rotational transfers typically represent instances in which an employee has successfully responded to a posting or advertisement for a position.

In the interest of retaining qualified individuals within the [FortisBC Holdings Inc.] group of companies, and recognizing that many NRB companies already contract with the Utility for human resource services (including common payroll systems and benefits packages), a non-rotational transfer will typically be considered an employee transfer rather than a termination and re-employment. In this manner, employees will not be subjected to a termination of continued employment status and the Utility and NRB will not be required to assume the administrative burden associated with a termination and new hire process.

As a non-rotational transfer is not specifically classified as a career development and training initiative, there will typically be no assurance of employment security from the Utility, unless such assurance is considered to be in the best interest of the Utility, in which case a specific agreement should be negotiated and documented. Any recruitment or administrative costs associated with a non-rotational transfer will be borne by the entity to which the employee is transferring.

4.3 Human Resource Sharing

These guidelines specifically recognize that human resource sharing initiatives can provide a variety of benefits to the Utility and NRBs. For example, circumstances occasionally occur in which the Utility and one or more NRBs each require an individual with similar skills and attributes, but the time commitment required by each entity is insufficient to justify the hiring of a full-time person. In the absence of a human resource sharing initiative, each individual entity would likely be forced to incur the significant cost associated with securing the services of an external consultant, whereas significant cost savings could be realized by hiring an individual on a full-time basis and entering into a cost sharing arrangement. This cost sharing method may also pay future dividends to the Utility by developing in-house expertise and experience rather than developing this expertise and experience in consultants. Additionally, Utility departments or NRBs that are subject to large fluctuations in human resource requirements may have individuals that are not fully utilized at all times, but for whom termination and subsequent re-hire is not a viable option (e.g. due to uncertainty of future availability, termination costs, retraining costs, etc.). In these instances, human resource sharing provides a mechanism through which the receiving entity can fulfil short term resource demands with a qualified individual, while the employing entity can eliminate inefficient salary and benefit costs.

Human resource sharing initiatives also represent an ideal mechanism through which to realize some of the career development and training benefits associated with a rotational transfer, without having to commit to the absolute loss of an individual's services for a certain period of time.

These guidelines are predicated upon the assumption that although all of the applicable entities benefit from human resource sharing initiatives, the employing entity is assuming the greatest degree of risk due to the need to ensure continued employment or incur termination costs. Therefore, a key principle of the human resource sharing initiative proposed by [FortisBC Energy] is that the employing entity will always retain first rights on the services of the individual in question, assuming reasonable notice is provided to the entity for which the individual is providing services at a given point in time.

Employment costs, including salary and benefits, will be allocated to the various entities on a pro rata basis, in accordance with the number of hours dedicated to each entity, and in a manner consistent with the [FortisBC Energy] Code of Conduct for the Provision of Utility Resources and Services.

5. Cost Collection Procedures

5.1 Work Orders

The Utility will be responsible for setting up the appropriate work order, documenting the work order number and ensuring that the appropriate individuals charge time to it. The providing organization's accounting group (typically [FortisBC Energy]'s Financial Accounting Group) will be responsible for maintaining the work order and collecting the appropriate charges.

5.2 Time Sheets

The individuals performing the service must report all time spent on that service by coding their time to the appropriate work order numbers. This is to occur whether the type of service is Specific Committed, As Required or Designated Subsidiary/Affiliate Service. Time sheets are to be sent monthly to the immediate supervisor or [FortisBC Energy]'s Payroll Department. The NRB shall also review the validity of these time sheets.

5.3 Invoicing

The NRB will be invoiced for the contracted amount in respect of Specific Committed Service and for the appropriate time based on the actual payroll level in respect of As Required Service or Designated/Affiliate Service (subject to confidentiality of salary information) with the applicable loadings applied.

The methodology for determining a salary level is on the basis of the average pay grade in the case of Management and Exempt employees or the exact wage grade in the case of bargaining unit employees.

6. Accounting for Services

6.1 Detailed Operating & Maintenance Expense Forecast

In the event that [FortisBC Energy] makes an application to the Commission for revenues related to operations and maintenance expenses (O&M), time estimates for Specific Committed Services will need to be estimated or forecast for each of the years covered by the application. These estimates or forecasts should be consistent with the relevant costs and assumptions contained in that application.

In the event that an activity change causes a reduction in the actual level of the Specific Committed Service compared to the annual budget (or revenue requirement application), [FortisBC Energy] will use these amounts to offset additional contributions from the NRBs. Net contributions received by the Utility through Transfer Pricing for As Required Service and Designated Subsidiary/Affiliate will be held in a deferral account for future return to [FortisBC Energy]'s customers.

6.2 Operating & Maintenance Expense Forecast Determined by Formula

In the event [FortisBC Energy] makes a multi-year application to the Commission for revenues related to O&M, and the allowed O&M level is determined by means of a formula, for the duration of the test period and in accordance with the terms of the Commission Order #G-85-97, [FortisBC Energy] will be entitled to capture the financial savings, such as cost reductions resulting from intercompany charges for RMDM or other NRB activities.

7. Review of Transfer Pricing Policy

The Transfer Pricing Policy will be reviewed on an annual basis as part of the Code of Conduct compliance review. However, [FortisBC Energy] may make application to the Commission for approval of changes to the policy including the pricing rules and the formula for determining full costs as and when required.

Appendix "A"

Example of Determining Full Cost for the Three Types of Service
(for an employee at a daily base pay of $300, concession loading of 25.48% and benefits loading of 15.75%)

Column	1		2			3
	Specific Committed Service		As Required Service			Designated Subsidiary I Affiliate
	Off-Site Full-time	On-Site Full-time	On-Site Short Term	Off-Site Short Term	Off Site Extended	
BASE PAY(Daily)	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00
PLUS:						
Concessions @ 25.48%	76.44	76.44	76.44	76.44	76.44	76.44
Benefits @ 15.75%	47.25	47.25	47.25	47.25	47.25	47.25
						423.69
GENERAL OVERHEAD	5%	10%	10%	10%	5%	5%
SUPERVISION	N/A	Direct Charge	20%	N/A	N/A	Direct Charge
AVAILABILITY CHARGE	N/A	N/A	20%	20%	20%	N/A
FACILITIES CHARGE (If Applicable)	N/A	$100.00	$100.00	$100.00	N/A	N/A
EQUIPMENT CHARGE (If Applicable)	Direct Charge	Direct Charge	Direct Charge	Direct Charge	Direct Charge	N/A
TOTAL COSTS PER DAY	$444.87	$566.06	$735.54	$650.80	$529.61	$444.87
Cost Ratios:						
to Base Pay	1.48	1.89	2.45	2.17	1.77	1.48
to Loaded Labour	1.05	1.34	1.74	1.54	1.25	1.05

* If the agreement between the NRB and Utility includes a right to immediate recall, the availability charge is waived. Prior notification to the Commission is required to waive the availability charge for As Required Service.

Attachment 207.1

IMPORTANT INFORMATION

B.C. Reg. 326/2008 Deposited November 7, 2008

M271/2008

Utilities Commission Act

DEMAND-SIDE MEASURES REGULATION

[includes amendments up to B.C. Reg. 228/2011, December 8, 2011]

Contents

Definitions

1 In this regulation:

"Act" means the *Utilities Commission Act*;

"bulk electricity purchaser" means a public utility that purchases electricity from the authority for resale to the public utility's customers;

"clean or renewable resource" has the same meaning as in the *Clean Energy Act*;

"community engagement program" means a program delivered by

(a) a public utility to a public entity either

(i) to increase the public entity's awareness about ways to increase energy conservation and energy efficiency or to encourage the public entity to conserve energy or use energy efficiently, or

(ii) to assist the public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or

(b) a public utility in cooperation with a public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently;

"education program" means an education program about energy conservation and efficiency, and includes the funding of the development of such a program;

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products or products that conserve energy,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems,

(d) conduct energy efficiency and conservation audits,

(e) on behalf of an organization, manage or advise with respect to the conservation or efficient use of energy in the organization’s facilities, or

(f) in an organization, educate other persons about the benefits of energy efficiency and conservation;

"energy-using product" has the same meaning as in the *Energy Efficiency Act* (Canada);

"expenditure portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act;

"low-income household" means a household whose residents receive service from the public utility and who have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut off established by Statistics Canada for that year for households of that type;

"plan portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act;

"public awareness program" means a program delivered by a public utility

(a) to increase the awareness of the public, including the public utility's customers, about ways to increase energy conservation and energy efficiency or to encourage the public, including the public utility's customers, to conserve energy or use energy efficiently, or

(b) to increase participation by the public utility's customers in other demand-side measures proposed by the public utility in an expenditure portfolio or a plan portfolio

but does not include a program to increase the amount of energy sold or delivered by the public utility;

"public entity" means a local government, first nation, non-profit society incorporated under the *Society Act* or trade union;

"regulated item" means

(a) a product or system that uses energy or controls or affects the use of energy

(b) an energy-using product,

(c) a building design, or

(d) Repealed. [B.C. Reg. 228/2011, s. 1 (d).]

(e) a building site design or building site selection plan, or

(f) a community design;

"school" means a school regulated under the *School Act* or the *Independent School Act*;

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program,

(d) a technology innovation program, or

(e) financial or other resources provided

(i) to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or

(ii) to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province;

"specified proposal" means

(a) a proposal respecting an amendment to the regulation referred to in paragraph (a) of the definition of "specified standard", if the proposal is published by the minister responsible for the *Energy Efficiency Act* and specifically refers to this regulation;

(b) a proposal respecting an amendment to the regulations referred to in paragraph (b) of the definition of "specified standard", if the proposed amendment is published in the Canada Gazette;

(c) a proposal respecting an amendment to a standard referred to in paragraph (c) of the definition of "specified standard", if the proposal is published by the government and specifically refers to this regulation;

(d) a proposal respecting

(i) a new bylaw, or

(ii) an amendment to a bylaw

referred to in paragraph (d) of the definition of "specified standard", if the proposal has been given first reading by the council of the local authority;

(e) a proposal respecting

(i) a new law, or

(ii) an amendment to a law

referred to in paragraph (e) of the definition of "specified standard", if the proposal has been published by the governing body referred to in that paragraph;

"specified standard" means a standard in any of the following:

(a) the Energy Efficiency Standards Regulation, B.C. Reg. 389/93;

(b) the Energy Efficiency Regulations S.O.R./94-651;

(c) the British Columbia Building Code, if the standard promotes energy conservation or the efficient use of energy;

(d) a bylaw of a local authority, if the standard promotes energy conservation or the efficient use of energy in the Province;

(e) a law passed by a governing body of a first nation, if the standard promotes energy conservation or the efficient use of energy in the Province;

"technology innovation program" means a program

(a) to develop, use or support the increased use of a technology, a system of technologies, a building design or an industrial facility design that is

(i) not commonly used in British Columbia, and

(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,

(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

[am. B.C. Reg. 228/2011, s. 1.]

Application

2 (1) This regulation applies only with respect to demand-side measures proposed by the authority.

(2) Effective June 1, 2009,

(a) subsection (1) is repealed, and

(b) section 3 does not apply to a public utility that is owned or operated by a local government or has fewer than 10,000 customers.

Adequacy

3 A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area;

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

Cost effectiveness

4 (1) Subject to subsections (1.5), (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of

(a) the demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(1.1) The commission must make determinations of cost effectiveness by applying the total resource cost test as follows and in the order set out:

(a) subject to subsections (1.2) and (1.3), the avoided natural gas cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is the amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia, multiplied by 0.5;

(b) subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is

(i) in the case of a demand-side measure of FortisBC Inc., an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia, and

(ii) in the case of a demand-side measure not referred to in subparagraph (i), an amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia;

(c) with respect to a demand-side measure not referred to in section 3 (a), do the following:

(i) increase the benefits of the demand-side measure by an amount that does not exceed an amount proposed by the public utility for this purpose, if the commission is satisfied that the amount represents the participant or utility non-energy benefits of the demand-side measure;

(ii) if the benefits of a demand-side measure have not been increased under subparagraph (i) or if the benefits of the expenditure portfolio of which the demand-side measure is a part has not been increased by 15% or more as a result of an increase under subparagraph (i), increase the benefit of the demand-side measure by an amount that

(A) increases by 15% the benefits of the expenditure portfolio of which the demand-side measure is a part, and

(B) is equal to the increase made under this subparagraph for all the other demand-side measures that are part of the expenditure portfolio.

(1.2) Subsection (1.1) (a) does not apply to a demand-side measure that reduces the use of natural gas but does not reduce greenhouse gas emissions associated with that use of natural gas.

(1.3) Subsection (1.1) (a) and (b) does not apply to a demand-side measure that encourages a switch from the use of oil or propane to the use of natural gas or electricity such that the switch would decrease greenhouse gas emissions in British Columbia.

(1.4) In considering a demand-side measure that, in the commission's opinion, will increase the use of a regulated item with respect to which there is either

(a) a specified standard that has not yet commenced, or

(b) a specified proposal,

the commission, after applying subsection (1.1), may increase the benefit of the demand-side measure by an amount that represents a portion of the avoided capacity and energy costs that, in the commission's opinion, will result from the commencement and application of the specified standard, amendment or new bylaw proposed by the specified proposal, assuming that the standard, amendment or new bylaw comes into force.

(1.5) Despite subsection (1.1) and subject to subsections (4) and (5), the commission must determine that a demand-side measure that is part of an expenditure portfolio and that is cost effective when applying subsection (1.1) is not cost effective if

(a) the demand-side measure is not cost-effective without applying subsection (1.1), and

(b) the total expenditures respecting

(i) the demand-side measure, and

(ii) all other demand-side measures that are part of the expenditure portfolio, that are not cost effective without applying subsection (1.1) and that are cost effective when applying subsection (1.1),

are more than

(iii) 33% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in gas rates, or

(iv) 10% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in electricity rates.

(1.6) For greater certainty, if the commission determines under subsection (1.5) that a demand-side measure that is part of an expenditure portfolio is not cost effective, the commission must exclude that demand-side measure from consideration when determining under that subsection whether another demand-side measure that is part of the expenditure portfolio is cost effective.

(1.7) For the purposes of subsections (1.1) (c) and (1.5), the commission, when considering the benefits or expenditures respecting a public utility's expenditure portfolio, may consider a demand-side measure of the public utility that is not included in the expenditure portfolio to be a part of the expenditure portfolio.

(1.8) Despite subsection (1.1), the commission may determine that a demand-side measure, other than

(a) a specified demand-side measure,

(b) a public awareness program,

(c) a demand-side measure referred to in section 3 (a), or

(d) a demand-side measure that is cost effective without applying subsection (1.1) but after applying subsection (1.4)

is not cost effective if the demand-side measure would not be considered cost-effective under the utility cost test.

(2) In determining whether a demand-side measure referred to in section 3 (a) is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, consider the benefit of the demand-side measure to be 130% of its value when determined without reference to this subsection.

(3) Repealed. [B.C. Reg. 228/2011, s. 2 (d).]

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program", the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) Repealed. [B.C. Reg. 228/2011, s. 2 (d).]

[am. B.C. Reg. 228/2011, s. 2.]

[Provisions relevant to the enactment of this regulation: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, section 125.1 (4) (e)]

Attachment 208.3

Marbek

Conservation Potential Review – 2010 FortisBC

Impact of CPR-2010 Natural Gas Savings on the B.C. Economy (2010-2030)

Submitted to
FortisBC

Submitted by
ICF Marbek

in association with
The Cadmus Group, Inc
Willis Energy Services

May 2011

222 Somerset Street West, Suite 300
Ottawa, Ontario, Canada K2P 2G3
Tel: +1 613 523-0784
Fax: +1 613 523-0717
info@marbek.ca
www.marbek.ca

Table of Contents

List of Exhibits

1 Introduction

In addition to energy savings, DSM programs can have broad impacts on the provincial economy as measured through metrics such as employment, GDP, and industrial output. Impacts arise from short term investment activities, such as building retrofits, and longer term changes in household/business spending, which can be attributed to the persistence of energy savings.

This analysis uses the results from the FortisBC Conservation Potential Review (CPR) Update 2010 to provide an estimate of the net macroeconomic impacts expected from implementing the achievable potential scenarios outlined in the main sector reports. The impacts reported in this analysis are specific to British Columbia and include the following measures of economic activity:

- Changes in Output (total industry revenues). This measures the value or amount of a good or service produced by an industry. This includes all production costs, including intermediate goods. Put differently, one can interpret output as the *total economic impact within an industry*.

- Changes in GDP at factor cost (total value-added at producers' prices, or total output minus costs of production). This is a measure of the value added to the economy and does not include the cost of resources consumed during production. One can interpret GDP at factor cost as a *net economic impact within an industry*. Based on these definitions, changes in output always exceed changes in GDP at factor cost. Finally, note that the term "net" used here is not the same as our use of "net" when referring to program impacts in the following section; net impacts of the DSM programs reflect changes in all industries rather than a single industry.

- Changes in employment (number of jobs).

The above economic impacts are reported for three sectors (residential, commercial and industrial) under the most likely and aggressive achievable potential scenarios at two milestone years: 2021 and 2030.

2 Approach

The analysis is based on the application of B.C. specific economic multipliers, which are a set of proportionality constants that relate changes in domestic production in a particular sector to its impacts on the entire B.C. economy. BC Stats released a report[1] in March 2008 documenting the British Columbia provincial economic multipliers based on 2004 economic data.

The multipliers contained in the BC Stats report noted above were applied to activities across all sectors that would be affected by the achievable potential results contained in each of the CPR sector reports. The impacts (both positive and negative) were then totalled to determine the net impacts, which are relative to the baseline scenario where no new DSM program initiatives are implemented by FortisBC. Essentially, ratepayer money is being shifted from a general basket of goods and services and applied to DSM program activities, which is modeled as a zero-sum situation.[2]

It should be noted that the effects of energy performance standards and naturally occurring market transformation induced by FortisBC's DSM programs, which increase program savings over time, are not included in the reported impacts; consequently the results presented are a conservative estimate of the overall impacts of natural gas energy efficiency initiatives.

The analysis was conducted in three steps:

1. A DSM mapping framework was created.
2. The investment (capital and labour) required by the DSM activities contained in each of the achievable potential scenarios was calculated and allocated into each category using the DSM framework established in Step 1.
3. Economic multipliers were applied, by category, to the investment amounts developed in Step 2.

Further discussion of each step is provided below.

2.1 Step 1: Create DSM Mapping Framework

The first step was to develop a framework to translate the CPR energy results into economic inputs. Exhibit 1 shows how the energy-efficiency investment activities represented by the CPR's achievable potential scenarios and the results from those activities are mapped to the appropriate economic categories contained in the B.C. economic model.

---

[1] Garry Horne; *2004 British Columbia Provincial Economic Multipliers and How to Use Them;* BC Stats; March 2008.

[2] This is in contrast to "gross" impacts, which do not account for losses that occur as a result of activities modeled in the analysis. For example, the numbers reported in the BC Hydro analysis are gross and do not take into account the employment displaced due to potential supply-side projects avoided by DSM activities.

Exhibit 1 Map of DSM Activity to BC Stats Classification

BC Stats Classification	Description	CPR related DSM Activity
Induced impacts from wages and salaries (per CAN 2007$ saved)	General household spending in the economy is affected by the energy-efficiency strategy	▪ Increased disposable income from energy savings occurring in the year of analysis ▪ Increased ratepayer costs to fund DSM programs and incremental costs for the year of analysis
9 NATURAL GAS DISTRIBUTION, WATER, SEWAGE AND OTHER SYSTEMS	Lost utility revenue due to persistence of energy savings	Reduced final demand for gas distribution as a result of gas savings occurring in the year of analysis
10 CONSTRUCTION	Home weatherization and efficient whole building construction	Labour costs associated with construction and installation of measures in the year of analysis ▪ Building envelope ▪ Whole building measures ▪ Installation of equipment
22 NON-METALLIC MINERAL PRODUCT MANUFACTURING	Insulation materials	Production costs of ▪ Insulation measures (wall, roof, pipe, duct, DHW tank)
24 FABRICATED METAL PRODUCTS MANUFACTURING	Increased production of fabricated metal products	Production costs of ▪ Boilers, Condensing DHW boilers ▪ Heat recovery ▪ Faucet aerators ▪ Showerheads/Spray valves
25 MACHINERY MANUFACTURING	Increased production of machinery	Production costs of ▪ Rooftop units, Furnaces/Unit heaters ▪ Heat pumps ▪ CHP ▪ Pool heaters
27 ELECTRICAL EQUIPMENT, APPLIANCE AND COMPONENT MANUFACTURIN	Increased production of electrical equipment and appliances	Production costs of ▪ Ventilation /Fans ▪ Thermostat ▪ IR heaters ▪ Water heaters (all kinds)
31 WHOLESALE TRADE	Commercial/industrial equipment purchases go through wholesalers	Assume 15% wholesale margin
32 RETAIL TRADE	Residential equipment purchases go through retail store	Assume 15% retail margin
44 PROFESSIONAL, SCIENTIFIC AND TECHNICAL SERVICES	Program advertisement budget, consulting, implementation contractor	Assume 5% on top of equipment and labour annual investments
45 ADMINISTRATIVE AND SUPPORT SERVICES	Program admin budget	Assume 5% on top of equipment and labour annual investments

2.2 Step 2: Monetize Achievable Potential DSM Activities

Using the framework established in Step 1, inputs to the macroeconomic impact analysis were developed from the CPR results. The analysis first determined the monetary impact for each category in the preceding table for each scenario analyzed. The first category, wages and salaries, assumes that energy bill savings[3] from all sectors eventually result in changes to disposable spending. This can be approximated as an increase in wages/salaries. However, the increased disposable spending comes at a cost: lost utility revenue due to DSM activities.[4] This loss is captured in the second row of the table by the natural gas industry.

Note that we do not consider changes in utility rates over the study timeframe and assume that gas not consumed as a result of DSM programs is exported outside of the BC region. As FortisBC passes through commodity and midstream charges without mark-up, we gross down the expected lost revenue by the following percentages to get the gas distribution lost revenue portion of the total bill: 30% (residential), 27.5% (commercial), and 15% (industrial).[5]

All other categories represent investment activities that increase final demand for various goods and services. The level of investment was calculated based on the actual measures included in the achievable potential scenarios as reported in each of the sector reports. Incremental equipment and labour costs were reported separately for each measure. The model assumes that most residential equipment measures are purchased at retail stores while commercial and (most) industrial systems are purchased through wholesalers; the retail/wholesale margin of 15% is applied to the retail trade industry while the remaining 85% of consumer prices are allocated to the appropriate industries. For example, every $100 worth of showerheads purchased at the store, $15 was allocated to “retail trade” and $85 to “fabricated metal product manufacturing”.

Investment activities related to the administration and implementation of the DSM programs are allocated to the following categories shown in Exhibit 1:

- 44 PROFESSIONAL, SCIENTIFIC AND TECHNICAL SERVICES and
- 45 ADMINISTRATIVE AND SUPPORT SERVICES.

The analysis assumes a combined overhead of 10% (5% Professional plus 5% Administrative) on the total installed costs described in the preceding Exhibit 1. This corresponds to 20% of program costs if Fortis’ average conservation incentive is 50% of installed incremental cost. This level of administrative expense is consistent with other gas programs in North America.

Finally, the ratepayer experiences increased costs to cover the DSM programs and the incremental costs[6] of the efficiency activities.

---

[3] Estimated by using the following rates: $9.2/GJ (commercial) and $9.8/GJ (residential) and $6.5/GJ (industrial). It is difficult to predict how the commercial and industrial bill savings would be re-spent in the regional economy so it is assumed that cost savings either get passed down to customers or to employees in the region.

[5] Based on current natural gas commodity rates, if rates were to increase then the percentage of the total bill represented by the volumetric delivery change would decrease.

[6] Depending on the application and replacement conditions, incremental and full costs may be equal.

2.3 Step 3: Apply Economic Multipliers

The final step involves application of the appropriate model multipliers to the monetized direct activities from the previous step; the multipliers used for each category are shown in Exhibit 2.[7]

Exhibit 2 Economic Multipliers

BC Stats Classification	Output/Revenue[8]	GDP at Factor Cost[9]	Employment[10] Per $1 million CAN $2007 saved
Induced impacts from wages and salaries	0.809	0.458	6.860
9 NATURAL GAS DISTRIBUTION, WATER, SEWAGE AND OTHER SYSTEMS	1.250	0.860	4.190
10 CONSTRUCTION	1.540	0.590	10.000
22 NON-METALLIC MINERAL PRODUCT MANUFACTURING	1.580	0.670	7.480
24 FABRICATED METAL PRODUCTS MANUFACTURING	1.300	0.560	7.090
25 MACHINERY MANUFACTURING	1.320	0.570	6.130
27 ELECTRICAL EQUIPMENT, APPLIANCE AND COMPONENT MANUFACTURIN	1.650	0.620	6.990
31 WHOLESALE TRADE	1.460	0.810	12.050
32 RETAIL TRADE	1.470	0.820	20.000
44 PROFESSIONAL, SCIENTIFIC AND TECHNICAL SERVICES	1.510	0.800	14.530
45 ADMINISTRATIVE AND SUPPORT SERVICES	1.480	0.830	23.100

The multipliers for output and GDP represent impacts on the entire economy due to an increase or decrease in domestic production. Multipliers for employment impacts are per one million dollars in direct changes to a category. For example, assume that an activity increases

---

[7] A comprehensive discussion of the BC multipliers is included in the previously cited report by Garry Horne.

[8] Multipliers are broken down into specific components (direct, indirect, induced, etc.) in the 2008 report. Industry multipliers for output are calculated from the report by combining direct and indirect multipliers (1+total indirect). Direct changes in output brought on by DSM activities are by default “one” and indirect changes in the rest of the economy are represented by “total indirect,” which is provided in a table in the referenced report

[9] Multipliers for GDP and Employment are produced by adding the direct and total indirect components.

[10] Multipliers are for the scenario *With Safety Net*. As explained in the BC Stats report, this scenario assumes that those who lose their jobs stay in the province and collect unemployment insurance or other social assistance; new jobs are filled by people formerly receiving assistance. Since costs in the CPR are in $2011, we use the CPI inflation calculator to translate $2011 into $2007 before applying employment multipliers. www.bankofcanada.ca/en/rates/inflation_calc.html

output in the construction industry by $1 million. The total impacts on the BC economy would be:

- Output = $1 million x 1.540 = $1.540 million
- GDP = $1 million x 0.590 = $0.590 million
- Employment = $1 million x 10.00 jobs/$1 million = 10 jobs

3 Results and Conclusions

The results of the analysis are presented in the following exhibits:

- Exhibit 3 shows the economic impacts that occur in 2021, by sub sector and economic indicator for the most likely achievable scenario.
- Exhibit 4 shows the economic impacts that occur in 2021, by sub sector and economic indicator for the aggressive achievable scenario.
- Exhibit 5 shows the economic impacts that occur in 2030, by sub sector and economic indicator for the most likely achievable scenario.
- Exhibit 6 shows the economic impacts that occur 2030, by sub sector and economic indicator for the aggressive achievable scenario.

Annual DSM Expenditures are included in each table and include all ratepayer investments required for that benchmark year, which includes program administration/implementation, labour, and equipment costs. Energy savings for each year are also annual, but include savings from measures installed from previous years up to the useful lifetime.

Exhibit 3 Economic Impacts, 2021, Most Likely Achievable Scenario

Sector	Assumed Annual DSM Expenditure	Output	GDP	Employment
Residential	$45,675,316	$35,134,637	$11,374,417	207
Commercial	$9,303,164	$15,801,465	$6,226,142	132
Industrial	$4,009,526	$7,289,923	$3,100,698	56
Total	$58,988,006	$58,226,025	$20,701,256	394
Impact per $1 million spent on DSM		$987,082	$350,940	6.7

Exhibit 4 Economic Impacts, 2021, Aggressive Achievable Scenario

Sector	Assumed Annual DSM Expenditure	Output	GDP	Employment
Residential	$105,800,196	$79,764,622	$25,635,718	462
Commercial	$13,552,259	$22,386,788	$8,807,267	185
Industrial	$6,530,929	$11,686,748	$4,949,398	89
Total	$125,883,383	$113,838,158	$39,392,383	736
Impact per $1 million spent on DSM		$904,314	$312,928	5.8

Exhibit 5 Economic Impacts, 2030, Most Likely Achievable Scenario

Sector	Assumed Annual DSM Expenditure	Output	GDP	Employment
Residential	$47,759,079	$42,655,567	$14,663,414	289
Commercial	$12,323,293	$28,916,837	$12,182,648	266
Industrial	$3,901,902	$10,681,592	$4,918,478	88
Total	$63,984,274	$82,253,997	$31,764,540	643
Impact per $1 million spent on DSM		$1,285,535	$496,443	10.0

Exhibit 6 Economic Impacts, 2030, Aggressive Achievable Scenario

Sector	Assumed Annual DSM Expenditure	Output	GDP	Employment
Residential	$78,408,933	$71,870,330	$24,889,914	493
Commercial	$17,604,257	$39,554,252	$16,630,752	361
Industrial	$5,290,263	$14,495,051	$6,671,977	119
Total	$101,303,454	$125,919,633	$48,192,643	973
Impact per $1 million spent on DSM		$1,242,994	$475,726	9.6

3.1 Conclusions

The analysis determined that the *net* impacts of DSM programs are overwhelmingly positive for the regional economy as measured by output, GDP, and employment. As illustrated in the preceding exhibits:

- The net impacts on output, GDP, and employment are all positive across all sectors for every scenario. This occurs because the DSM program shifts spending from low multiplier industries to industries with higher multipliers.
- Annual impacts increase over time and are larger for the aggressive achievable scenarios. This arises due to the accumulation of energy savings from measures installed in prior years.
- The residential sector, in every scenario, accounts for the greatest share of economic impacts. This is most likely due to the early replacement measures in this sector.
- By 2021, the net employment gains from CPR activities will range between 362 - 682 jobs, depending on scenario. This translates to between 5.8 – 6.7 jobs per $1 million invested in DSM that year.
- By 2031 the net employment gains from CPR activities would grow to between 580 - 881 jobs, depending on scenario. This translates to between 9.6 – 10.0 jobs per $1 million

invested in DSM that year. The increase in number of jobs per $1 million invested in 2031 includes the beneficial effects of DSM investments made in prior years.

- Benefits will continue to accrue after 2030, due to investments made in prior years, until the effective life of the installed program measures has been exceeded.

Marbek

222 Somerset Street West, Suite 300
Ottawa, Ontario, Canada K2P 2G3
Tel: +1 613 523-0784
Fax: +1 613 523-0717
info@marbek.ca
www.marbek.ca

Project ID: 10041

Attachment 211.1

205.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, pp. 15-16

Elements of Existing EEC Framework to be Retained

"Most aspects of the existing EEC framework continue to make sense going forward. The key approvals previously granted to which the Companies are proposing no change are as follows:

- *The Commission approves an overall funding envelope comprised of a portfolio of approved program areas. Consistent with that notion, the Companies will continue to have the ability to move funds between programs and program areas to optimize the portfolio;*

- *Continue to use the portfolio level approach to benefit-cost analysis such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the portfolio using the Societal Cost Test as discussed in Part 5.2.2 below);*

- *Continue to evaluate the Innovative Technologies portfolio of activity on a separate segment of the overall portfolio, with a weighted average benefit-cost test result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the Innovative Technologies portfolio using the Societal Cost Test, as the Companies are proposing in Part 5.2.2 below that the Societal Cost Test be used for all EEC activity, including Innovative Technologies);*

- *Continue to be able to offer programs and measures with a benefit-cost result of less than 1.0, but provide information in annual reporting as to why the program should continue, including information on any environmental or social or other goals supported by the program or measure;*

- *Continue to use the approved accountability mechanisms that the Companies have put in place, that is the EEC Stakeholder group, and EEC Annual Report, which offer the Commission and Stakeholders the opportunity to comment on proposed program activity. The EEC Annual Report includes a supporting rationale for funding transfers between approved program areas and funding transfer impacts. It also includes reporting on the benefit-cost analysis, and justification for continuing with programs and measures with a benefit-cost result of less than 1.0."*

205.1 For each the above listed bulleted aspects of the EEC framework for which the FEU believes previous approvals have been granted, please provide references to those approvals. Please reference all applicable Parts of applications, information requests, Commission decisions and negotiated settlements.

Response:

Please refer to the following table.

FortisBC Energy Utilities ("FEU"), comprised of FortisBC Energy Inc. ("FEI" or "Mainland"), FortisBC Energy (Vancouver Island) Inc. ("FEVI" or "Vancouver Island"), FortisBC Energy (Whistler) Inc. ("FEW" or "Whistler"), and FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), collectively also referred to as the "Companies" or the "Utilities" 2012-2013 Revenue Requirements and Natural Gas Rates Application	Submission Date: June 30, 2011
Response to British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1	

FEU Proposed Existing EEC Framework to Continue Going Forward	**Reference to Appropriate Decisions**	**Quotations from Appropriate Decisions**
Companies will continue to have the ability to move funds between programs and program areas to optimize the portfolio.	Order G -36-09, Page 42	*Commission Panel directs that the annual EEC Report include the following:* • *any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*
Continue to use the portfolio level approach to benefit-cost analysis such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. Note: the FEU are proposing a change from the TRC to the SCT as the appropriate benefit-cost test	Order G- 36-09, Page 32	*The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives.*
	Order G - 141-09, Page 6 and 7, Section 11d and 12e	*All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6)…*
	Order G - 140-09, Page 8 and 9, Section 6c and 7d	*All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15)…*
Continue to evaluate the Innovative Technologies portfolio of activity as a separate segment of the overall portfolio, with a weighted average benefit-	Order G - 141-09, Page 6 and 7, Section 11d and 12e	... *Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. …*

FEU Proposed Existing EEC Framework to Continue Going Forward	Reference to Appropriate Decisions	Quotations from Appropriate Decisions
cost test result of 1.0 or greater.	Order G - 140-09, Page 8 and 9, Section 6c and 7d	*…Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more….*
Continue to be able to offer programs and measures with a benefit-cost result of less than 1.0, but provide information in annual reporting as to why the program should continue, including information on any environmental or social or other goals supported by the program or measure.	Order G -36-09, Page 32	*The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives. Consequently, it is important for the components of any portfolio to be capable of analysis on an individual basis. The Commission Panel directs that Terasen include in its annual EEC Report to the Commission the results of the RIM, UC, TRC and Participant tests for each proposed DSM in its portfolio, and provide justification for continuing with any measures or groups of measures which have a TRC of less than 1.0.*
Continue to use the approved accountability mechanisms that the Companies have put in place,	Order G- 36-09, Page 42	*The Commission Panel accepts Terasen's accountability undertakings*[49]

[49] Please note that the proposal for accountability mechanisms was as follows:

…Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs.

FEU Proposed Existing EEC Framework to Continue Going Forward	Reference to Appropriate Decisions	Quotations from Appropriate Decisions
that is the EEC Stakeholder group, and EEC Annual Report, which offer the Commission and Stakeholders the opportunity to comment on proposed program activity. The EEC Annual Report includes a supporting rationale for funding transfers between approved program areas and funding transfer impacts. It also includes reporting on the benefit-cost analysis, and justification for continuing with programs and measures with a benefit-cost result of less than 1.0.	Order G -36-09, Page 42	*Commission Panel directs that the annual EEC Report include the following:* • *TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.* • *any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*
	Order G - 141-09, Page 6 and 7, Section 11d and 12e	*…TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.*
	Order G- 140-09, Page 8 and 9, Section 6c and 7d	*…TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.*

205.2 To the best of the FEU's knowledge, do other utilities in BC operate under this framework? If not, does the FEU consider consistency in use of funding frameworks important for the utilities in BC?

Response:

The FEU believe that the framework should be utility specific, as it is currently the case in BC. Some elements of the framework can be applied to all utilities, but for the most part the framework should be designed to meet the EEC objectives of individual utility programs.

205.3 Please describe the level of DSM expertise among the members of the EEC Stakeholder Committee.

Response:

The level of DSM expertise among the members of the EEC Stakeholder group varies. One aim of the FEU in establishing the EEC Stakeholder group was to offer opportunities for EEC initiative input to a fairly wide variety of stakeholders as the FEU felt there would be value in having a number of perspectives around the table. The EEC Stakeholder group includes some Regulatory Intervenors, senior representatives from BC Hydro PowerSmart and FortisBC Inc. (electric) PowerSense, representatives from the City of Vancouver and the Ministry of Energy and Mines Energy Efficiency Branch and the BCUC, all of whom could be described as having a relatively high degree of DSM expertise. The Stakeholder group also includes equipment manufacturers and suppliers, gas contractors, the new construction industry, and customer groups such as multi-unit residential buildings and manufacturers, who could fairly be described as having a lower degree of DSM expertise than the first group as it pertains specifically to DSM-specific matters; however, these members bring other, valuable perspectives to the group, such as knowledge of energy-consuming equipment and installations, construction matters and customer views. The Companies' view is that the wide range of perspectives on the EEC Stakeholder group significantly enhances the value of the input the FEU receive from the group.

205.3.1 Is the FEU aware of the membership in DSM Stakeholder or Advisory committees in other jurisdictions? Please describe.

Response:

Yes; the FEU are members of the BC Hydro EC&E Committee, which similar to the FEU EEC Stakeholder group, is a varied group. The FEU are also familiar with Avista's External Energy Efficiency board, which is also a varied group.

205.4 What regulatory processes took place around the FEI-FEVI 2009 EEC Report and the 2010 EEC Report? Were the reports ever approved by the Commission?

Response:

The Commission, in its EEC Decision, by Order No. G- 36-09, directed the Companies to file annual EEC reports on all of the EEC initiatives and activities, expenditures and results. The Companies have subsequently filed the 2009 and 2010 EEC Annual Reports in order to satisfy the requirements of the EEC Decision. These reports are compliance reports, and there was no formal regulatory process that took place around the 2009 and 2010 EEC Annual Reports. The Commission does not normally approve or not approve compliance reports.

IN THE MATTER OF

THE FORTISBC ENERGY UTILITIES

[comprised of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.]

2012-2013 REVENUE REQUIREMENTS AND RATES

DECISION

April 12, 2012

Before:

D.A. Cote, Commissioner/Panel Chair
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

8.6.3 EEC Framework

In the Application, the FEU have requested that the elements of their existing EEC Framework be retained. Those elements, which the FEU refers to as "accountability mechanisms" are:

- An overall funding envelope is approved by the Commission and EEC spending is not to exceed that level;
- The FEU will spend EEC funds only on approved Program Areas;
- The Companies have the ability to move funds among Program Areas and the FEU will report on those funding transfers in their EEC Annual Report;
- The FEU evaluate the EEC portfolio as an overall portfolio and monitor the portfolio TRC on a monthly basis;
- The FEU evaluate the Innovative Technologies Program Area as a separate segment having a benefit-cost ratio of 1.0 or greater;
- The Companies will hold EEC Stakeholder Group meetings and present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs; and
- The FEU will file an EEC Annual Report with the Commission by the end of the first quarter of every year.

(Exhibit B-1, p. 775, and Exhibit B-1, Appendix K-1, pp. 4-5)

i) Funding Envelopes and Transfer of Funds Among Program Areas

The FEU have requested approval to: (a) have an overall funding envelope approved by the Commission; (b) only spend funds on approved Program Areas and (c) retain the right to move funds among approved Program Areas, reporting such transfers in their EEC Annual Report and to the EEC Stakeholder Group. (Exhibit B-1, Appendix K-1, p. 4)

The process for the FEU making funding transfers was examined during the Oral Hearing. The Companies stated that they file information on funding transfers in their EEC Annual Report and then discuss the Annual Report, at a high level, with their EEC Stakeholder Group. There is no suggestion that proposed funding transfers are discussed with the Group in advance. The FEU admit they have not contemplated what they would do in the situation where they make a funding transfer before presenting it to the Stakeholder Committee and when it is presented, the Stakeholder Group subsequently expresses opposition. (T9: 1472, 1474)

Commission Determination

The EEC Annual Report is a compliance filing. The FEU are currently not restricted from making funding transfers prior to review through a Stakeholder Committee meeting. Given this and the FEU's further lack of any process to deal with cases where the Stakeholders may oppose the transfer, the Commission has concerns with the lack of a third-party review of the Companies' funding transfers. This could lead to expenditures in specific programs growing to a level well in excess of what had been approved with no additional scrutiny. The Commission believes that to ensure proper oversight and accountability, it must balance the advantages of the FEU being able to move funds freely among approved Program Areas to meet the needs of existing or new programs against the need for the Commission to be assured that EEC expenditures continue to be in the public interest. **To achieve this balance, the Commission Panel has determined that the practice of transferring funds among Program Areas should be allowed to continue but with some limitations. Accordingly, the Commission approves the movement of funding to a maximum of 25 percent from one approved Program Area to another approved Program Area without prior approval of the Commission. In cases where a proposed transfer into an approved Program Area is greater than 25 percent of that approved Program Area, prior Commission approval is required. Finally, the transfer of funds to new programs, not approved in this Application, or to Innovative Technologies (see below) will require prior Commission approval.**

ii) Portfolio Approach to Cost Effectiveness Screening

The FEU advocate the continued use of a portfolio approach for evaluating the cost effectiveness of

EEC programs. None of the Interveners objected to the continuation of this practice.

The FEU propose to monitor EEC programs on a monthly basis to ensure the overall EEC portfolio continues to meet the cost effectiveness test on an ongoing basis. (FEU Final Submission, pp. 184, 185)

Commission Determination

With the assurance that FEU will continue to monitor EEC programs on a monthly basis to ensure the EEC portfolio meets an MTRC of 1 or greater, the Commission approves the assessment of cost effectiveness on an overall portfolio basis, subject to further determinations regarding the Innovative Technologies Program Area discussed below.

iii) Innovative Technologies

In the Negotiated Settlement Agreement for 2009 and 2010, parties agreed that the Innovative Technologies Program Area is to be evaluated as a separate segment of the overall EEC portfolio and is to have a weighted average total resource cost (TRC) of 1.0 or greater.

The Innovative Technology Program Area consists of pilots and demonstration projects to develop technologies and programs to be market-ready. The FEU submit "[t]he point of innovative technology programs is to jump start fledgling market-ready technologies with substantial promise of greenhouse gas, energy-efficiency, and other benefits." (Exhibit B-9, BCUC IR 1.197.1)
In the current application the FEU is requesting approximately $3.0 million in EEC funding spread over two years.

Commission Determination

The Commission Panel views the Innovative Technologies Program Area as similar to a DSM

Research and Development department – it is the funding the FEU can use to test new technologies and run pilots. The Panel understands that the programs in this Program Area will not always be cost-effective. **Accordingly, the Commission Panel lifts the requirement for the Innovative Technologies Program Area to be evaluated as a separate segment of the EEC portfolio meeting TRC of 1 or greater as agreed to in the NSA for the 2010 and 2011 RRA. However, the Panel further determines that these programs need not meet the new MTRC test. The expenditures in this Innovative Technologies Program Area are subject to the portfolio level cost-effectiveness testing discussed above and are subject to the 33 percent cap for expenditures that do not pass the MTRC test as written in the DSM *Regulation* as discussed in Section 8.2. However, because these technologies may fall into the category of activities being dealt with by the AES Inquiry, the Panel directs that transfers of funds into or out of this program area are not to occur without prior Commission approval.**

iv) Stakeholder Group and EEC Annual Report

The FEU's EEC Stakeholder Committee does not have a Terms of Reference (TOR) although a draft had been tabled with the group shortly before the Oral Hearing. (Exhibit B-83, Undertaking 50) The TOR has not yet been approved by the Committee. As noted previously, the FEU concede that there is no current process for the stakeholder group to take a position on any issue and no process to deal with a situation where a member disagrees with a funding transfer. (T9: 1515, 1519) Further, the Companies concede that there are no formal processes for the EEC Stakeholder Group to critique and shape the FEU's programs. (T9: 1519, 1521-2)

The FEU submit that they solicit feedback from stakeholders and describe the group as "lively" and "would anticipate that if anyone had a major issue with program design or a particular program activity, they would raise it with us." (T9: 1519)

During the Oral Hearing the FEU EEC panel was asked whether their current approach gives them "carte blanche" in terms of the decision-making on the use of EEC funds. (T9: 1524) In response, Mr. Stout stated: "I don't think it does. And I say that because of the way the meetings are conducted, and the input taken back, and how we deal with it..." Ms. Smith further stated that "we're managing a portfolio of activity to a set of cost-effectiveness guidelines. We provide very extensive reporting on that activity." (T9: 1524)

The FEU currently provide the Commission with an annual report that in part,

- Evaluates EEC expenditures on an overall portfolio basis; and
- Reports on funding transfers between approved program areas.

Commission Determination

The Commission Panel's view is that if the Stakeholders are to have influence on the use of EEC funds, the group needs to have its feedback mechanisms and decision-making processes formalized in a Terms of Reference. The Commission Panel believes there is a continuing need for an active and effective EEC Stakeholder group, particularly in light of the expanding range of EEC activities being undertaken by FEU.

In order to increase the effectiveness of the EEC Stakeholder Group, the Commission Panel directs the FEU to develop a Terms of Reference in consultation with the Stakeholder Group. The Commission further directs the FEU to continue filing an Annual Report to the Commission but to add to this report a section detailing the EEC Stakeholder Group's views with attention to items such as funding transfers, new programs and any other material the Stakeholder Group deems appropriate and wishes to provide.

v) Programs that have Previously Been Rejected

In the TGI-TGVI 2009 Energy Efficiency and Conservation Programs Decision[24], the Commission rejected the NGV EEC Program and the Trade Relations Program. The NGV EEC Program was reviewed and dealt with in the EEC NGV Incentives Review Decision.

Prior to this Application, the FEU started their Efficiency Partners program which is substantially similar to the Trade Relations Program. The FEU are proposing to continue the Efficiency Partners program and submit that the 2009 EEC Decision[25] anticipated that the Trade Relations type of work would be undertaken in the Residential Program Area and that the FEU were transparent in reporting and consulting with stakeholders on these types of activities. (FEU Final Submission, p. 212)

The FEU did agree that it would be problematic to re-instate a Program Area that had been previously rejected. (T9: 1522-3)

While the Commission Panel sees merit in the Efficiency Partners program in this Application and approves it, the Commission recognizes that this program, under a different name was rejected previously. The Commission Panel considers it problematic for the FEU to re-instate a program that has been previously rejected or to start a program that is substantially similar to one that was previously rejected with no additional process. **Accordingly, the Commission Panel directs the FEU not to re-instate programs or Program Areas that have previously been rejected without approval of the Commission. When a program or Program Area has been rejected, the Commission directs the FEU to apply to the Commission for approval prior to spending EEC funds on that program or Program Area.**

---

[24] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Energy Efficiency and Conservation Programs Application; Decision and Order G-36-09 dated April 16, 2009 (2009 EEC Decision)

[25] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Energy Efficiency and Conservation Programs Application; Decision and Order G-36-09 dated April 16, 2009 (2009 EEC Decision)

8.7 Other Identified Issues with EEC Portfolio

8.7.1 Evaluation, Measurement and Verification

During the Proceeding, the issue of the FEU's evaluation of their programs and the measurement and verification of their claimed energy savings was raised. The FEU submit that impact evaluations on three of their Residential and Commercial programs conducted between 2003-2010 have been completed. (Exhibit B-17, BCUC IR 2.97.1) In addition, they presented an evaluation schedule of their EEC programs for 2011 and 2012. (T9: 1477-8, Exhibit B-17, BCUC IR 2.118.1) This schedule includes more planned evaluations but the Companies state they have developed evaluation plans on a program by program basis. An overall evaluation plan has not been developed although the Companies have plans to hire a dedicated Evaluation, Measurement and Verification (EM&V) manager to develop "a formal structure and an evaluation framework" for all EEC programs. (T9: 1478, 1481) The FEU state that currently, all evaluations are conducted by third-party experts and the FEU submit that their evaluation process is in line with industry practice. (T9: 1481, FEU Final Submission, p. 209)

The FEU do not use the International Performance Measurement and Verification Protocol (IPMVP) although they have recently sent staff to the certification course. The FEU submit that there is no evidence that the IPMVP is widely used in the industry or that it is preferable to the methods used by the third party experts retained by the FEU.

The FEU argue that "they have employed a reasonable approach given the early stages of the EEC portfolio. The FEU are hiring an EM&V manager who will establish the appropriate EM&V framework." (FEU Final Submission, p. 210)

CEC agrees with the FEU and argue that "[t]he FEU's evaluation and measurement programs are evolving as expected and appropriate for the stage of development of EEC at which the FEU are now." (CEC Final Submission, p. 50)

Commission Decision

The Commission Panel sees benefit in the establishment of an EM&V Framework. **The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework.**

8.7.2 Integration with Other Utilities

BCSEA and its expert witness Mr. Plunkett raised the issue of integration of DSM programs among BC utilities. Mr. Plunkett's position is that "only one program should treat the customer to the extent that efficiency potential can be maximized and cost minimized with this approach" and that the FEU currently do a fair job of integrating gas and electric efficiency but that there is room for improvement. (Exhibit C4-5, BCUC IR 1. 11.1.1)

The FEU state that they do not have written protocols to prevent duplication between programs, but that department managers meet on a regular basis to compare programs and look for opportunities to cooperate. (Exhibit B-85, Undertaking 52, and T9: 1497)

The Companies agree that where programs are integrated it is important to avoid duplication of efforts to contact the same customer. They also agree that integrated programs may maximize use of ratepayer funds where customers' total energy (gas and electric) needs can be addressed.
(T9: 1496, 1506)

The FEU currently run 11 programs in partnership with other BC utilities but do not currently have attribution rules between utilities for claiming energy savings. (Exhibit B-25, p. 3, Exhibit B-17, BCUC IR 2.119.1)

Commission Determination

The Commission agrees with Mr. Plunkett that integration of DSM programs from utilities and providing one point of customer contact for all DSM services, regardless of fuel type, is an efficient means of delivering DSM. The Commission encourages FEU to continue to provide integrated DSM programs so customers can easily access services to reduce all their energy needs, regardless of energy source.

The Commission Panel believes there is a need for the FEU to develop attribution rules and communication or other protocols and agreements necessary to avoid duplication of programming and to work towards creating streamlined processes for customers wishing to access DSM for all energy use. We also believe there is a need for the FEU to develop attribution rules with other utilities for integrated programs. **Therefore, the Commission Panel directs the FEU to develop attribution rules for all integrated programs which prevent the double counting of savings.**

8.7.3 PSECA Program and Overlap with AES Inquiry

In 2010 and 2011, the FEU participated in the Public Sector Energy Conservation Agreement (PSECA) program with BC Hydro and SolarBC. The PSECA Initiative was operated by the provincial Climate Action Secretariat (CAS). Under the PSECA Initiative, the CAS reviewed and approved applications for incentive funding for public sector organizations to reduce energy consumption and GHG emissions. The CAS then forwarded applications to the FEU who independently reviewed their eligibility for EEC incentive funding. (Exhibit B-1, Appendix K-4, pp. 74-77) The CAS has not committed further funding to the PSECA Initiative so FEU's PSECA program has been discontinued for 2012-2013. The FEU ran their PSECA program under the Commercial Program Area.

In 2011, the FEU project to spend $324,430 on the PSECA program for three school districts (SD): SD 72 Campbell River; SD 71 Comox Valley; SD 37 Delta. High efficiency boilers, heat pump chillers, and high efficiency water heaters were the measures eligible for incentives. Approximately $116

Attachment 213.1.1

193.3 Does the FEU consider the proposed rate of return on the proposed energy efficiency deferral account a form of incentive to pursue all cost effective demand side management and energy efficiency?

Response:

The use of the word "Incentive" in the non-rate base EEC deferral account name is in reference to the type of EEC costs that are expected to make up the majority of the balance in the account. It is not meant to indicate that it provides an incentive to the Companies. Earning the Companies' regulated rate of return on EEC expenditures, however, does put an EEC investment on the same footing as any other investment in the utility, and absent any restrictions to capital investments would encourage the utility to purchase all cost-effective EEC opportunities. This matter was addressed at some length during the original EEC proceeding in 2008/2009. See, for example, the response to BCUC IR 1.43.2.4 series, BCUC IR 1.65.1 (2008

EEC Application, Exhibit B-2) and the BCUC IR 2.29 series (2008 EEC Application, Exhibit B-3) in that proceeding, which are provided in Attachment 193.3.

Please see also the response to BCUC IR 1.193.4.

193.4 Has the FEU considered other forms of performance incentives to achieve all cost effective demand side management and energy efficiency? If so, please provide detailed descriptions of each performance incentive model the Companies researched and considered.

Response:

The FEU provided discussion of its views on other forms of performance incentives in achieving all cost effective demand side management and energy efficiency in the 2008 EEC Application in the responses to BCUC IRs 2.29.1 to 2.29.6. Please also refer to the response to BCUC IR 1.193.3 and Attachment 193.3. The responses to the BCUC IR 2.29 indicate that the approach proposed in the EEC Application (and approved by BCUC Order No. G-36-09) of deferring EEC expenditures, including them in rate base and amortizing the deferred EEC expenditures in rates over a number of years provided an adequate and appropriate incentive to pursue all cost-effective EEC. This approach provides the FEU with the same fair return for investing in EEC as is received for investing in new gas infrastructure to accommodate load growth. The 2008 EEC IR responses also indicate that the accounting treatment proposed by the Companies to allow the FEU to earn a return on the EEC expenditures is consistent with Section 60(b)(ii) of the *Utilities Commission Act* that states:

> *"Provides to the public utility for which the rates is set a fair and reasonable return on any expenditure made by it to reduce energy demands"*

In the 2008 EEC Application IR responses the FEU opposed approaches that were based on treating EEC expenditures as current period expenses and provided an incentive to the Companies based on exceeding performance targets. It was argued that approaches of this type did not provide an adequate opportunity to earn a fair and reasonable return on EEC expenditures and were not therefore consistent with *UCA* Section 60 (b) (ii). The FEU indicated (in 2008 EEC BCUC IRs 2.29.3 and 2.29.4) that they would be open to considering an incentive based proposal that added performance based incentives on to a model that already included rate base treatment of EEC expenditures, fair return and amortization in rates.

The FEU continue to hold the views expressed in the 2008 EEC Application IR responses included in Attachment 193.3 is the response to BCUC IR 1.93.3 above. In addition the proposal in this Application to change the EEC benefit / cost test to the Societal Cost Test will, if approved allow a greater number of EEC programs to go ahead.

Attachment 193.3

43.2.4 On page 35 Table 3.5 Summary Information Other Utilities DSM Activity of the Application it shows the DSM Funding Treatment: O&M, rate base, and public purpose fund.

43.2.4.1 For these utilities that include the costs into rate base/capital what are the amortization periods.

Response:

Please refer to the response to BCUC IR 1.43.2.4.2

43.2.4.2 For these utilities that rate base its DSM expenditures please provide information on the amounts that are capitalized annually and the amounts expensed, if any.

Response:

The table below provides the details on amortization periods for utilities that include the costs into rate base/capital

Utility Name	Amortization Period	Capitalized vs. expensed
BC Hydro	10 yrs	Capitalized but DSM expenditures associated with cancelled programs are written off in the year in which the program is cancelled
FortisBC	10 yrs	Capitalized
Manitoba Hydro	15 yrs	Expensed but spread over a 15 year amortization period
Union Gas/Enbridge Gas Distribution	n/a	Included in rate base; earn based on an incentive mechanism

Further details for each utility are provided below.

BC Hydro

"Costs are capitalized and amortized to appropriately match the costs with energy savings benefits over future years, not to exceed ten years.

Costs incurred in the concept development phase are not capitalized as there is no assurance that any program will be accepted for development and implementation.

Program-specific and non-specific portfolio development and implementation costs are capitalized and amortized over a period not to exceed ten years. Amortization commences in the year following the year in which the expenditure is incurred. DSM expenditures associated with cancelled programs are written off in the year the program is cancelled. Costs that are not capitalized are expensed as OMG&A in the period incurred."

Source: http://www.bchydro.com/rx_files/info/info45426.pdf, Section 8, p71

DSM expenditure in 2007 was $4.942 million in operating costs and $47.313 in deferred capital.

Source: BC Hydro PowerSmart, "Report on Demand-Side Activities for the Twelve Months ending March 31, 2007"

FortisBC

All DSM expenditures are capitalized, including incentives, labour, expenses including advertising, but none are O&M. About ~10% of the Technical Advisors time is designated as Key Account management and thus O&M. However KAM is for non-DSM matters, so the O&M expense will go to Customer Services.

Also it is the *net* DSM expenditure, after income tax effect (~31%), that is capitalized in rate-base. So a $2.4m nominal spend translates into $1.6m rate base addition.

Source: Email Correspondence, Keith Veerman, FortisBC PowerSense Department.

Manitoba Hydro

The Terasen Utilities had asked Manitoba Hydro to clarify this, below is their response:

None of Centra's[12] DSM costs are capitalized. All of Centra's DSM costs are expensed, but they are spread out over the 15 year amortization period. Manitoba Hydro (the electrical operation) does not earn a return on DSM expenditures because as a crown corporation it is regulated under a cost of service methodology (not rate base/rate of return). Manitoba Hydro's return is based on long term forecasts and rates designed to leave an adequate operating reserve and debt/equity ratio. Return on rate base or like assets is not considered when determining rates. It should be noted that Centra also now regulated under a cost of service methodology but this is very recent and the Manitoba PUB still looks at rate base in Centra's filings and rate base is used as an allocater in its cost of service study.

Source: Email Correspondence, Brad De Ryck, Gas Rates & Regulatory Department Manitoba Hydro.

---

[12] Centra is the natural gas subsidiary of Manitoba Hydro.

Union Gas and Enbridge Gas Distribution

Both include costs in their rate base, but do not capitalize the expenditure. Uses a Variance Account to reconcile expenditure and revenue at the end of each financial year; neither company earns on the DSM revenue but rather through the SSM mechanism.

http://www.oeb.gov.on.ca/documents/cases/EB-2005-0437/decision-231205.pdf (Section 4 refers to the SSM and Section 6 to the DSMVA).

43.2.4.3 Are the Terasen Utilities aware of any utility that amortizes DSM costs over a 20 year or greater period? If so, please provide the name of the utility and the details of the DSM program.

Response:

Further research failed to uncover any examples where utilities are using or proposing amortization periods as long as 20 years. Note, however, that the 20 year period selected by the Companies is based on estimates of "the life of the assets". There are other instances where utilities have adopted the "life of the asset" approach, but arrived at a different conclusion as to the life of the assets (i.e. a shorter amortization period) in those particular circumstances. The approach is consistent with the Commission's DSM Accounting Policy and the Commission has approved this approach for FortisBC and BC Hydro.

Please also refer to the responses to BCUC IRs No. 1, Questions 10.2, 42.1 and 43.2.4.2. Similarly, the Nevada Administrative Code, NAC 704.9523[13], charges the Public Utility Commission with determining an amortization period that is "consistent with the life of the investment."

43.2.4.4 What is a "public purpose fund" and how is it generally funded? Would a public purpose fund be suitable for the Terasen Utilities?

[13] http://www.leg.state.nv.us/NAC/NAC-704.html#NAC704Sec9523conci

Response:

In general, a "Public Purpose Fund" (PPF) is a mechanism to raise revenues from utility customers for a specific purpose such as DSM, low-income support or the funding of renewable energy resources. The PPF charge typically appears as a separate line-item on the customer bill rather than being rolled into the rates, so it shows up as a rate rider in the utility's tariff. There are different variations on PPFs; in some cases, PPFs fund DSM activity by a central agency. In others, PPFs fund utility DSM activity. More information on this can be found in Appendix 4.

In the case of Oregon, the Public Purpose Fund was established by legislation – by Senate Bill 1149, which was approved in 1999 and which came into effect March 1, 2002. No such statutory basis exists for the Terasen Utilities to fund DSM activity through a PPF – this is one reason that a PPF would not be an appropriate funding vehicle for the Terasen Utilities EEC activity.

In British Columbia, each utility has applied for and managed its own DSM funding according to its particular circumstances and Commission approvals received. British Columbia utilities have also rolled their DSM funding into revenue requirements and rates in keeping with Commission orders. It would not be appropriate for some utilities in the province to be required to fund their DSM programs in the manner of a PPF while others rolled those expenditures into rates. The normal utility regulatory proceedings dealing with revenue requirements, rate design, resource acquisition and compliance reporting provide suitable opportunities to ensure that DSM funding is reviewed, approved and fairly charged in rates. The Energy Plan does not make mention of PPFs, but rather in Policy Action # 3 states that the Ministry will ensure that appropriate incentives are in place to encourage investor-owned utilities to pursue cost-effective DSM programs. The Companies believe that the financial treatment proposed in the Application provides for that financial incentive.

43.2.4.5 Please discuss the pros and cons of the various DSM funding treatments: O&M, rate base, and public purpose fund.

Response:

The pros and cons of the DSM funding treatments in general are discussed below, however in every jurisdiction, nuances in ratemaking exist that impact how the pros and cons laid out below would be experienced or not by each individual utility.

O&M:

Pros: The DSM expenditures are recovered in rates in the same fiscal period in which they are incurred so there is no residual to recover in future fiscal periods.

Cons: Expensing the DSM expenditures in O&M does not allow matching of the EEC costs with the DSM benefits produced which will persist over a number of years. Current customers pay for benefits that will be received by future customers.

To the extent there is year to year variability in the level of DSM spending, expensing the DSM expenditures in O&M will introduce rate volatility.

In order to encourage a utility to make DSM expenditures, an accompanying incentive mechanism is needed, which can be more difficult to administer than including expenditures in rate base and amortizing.

Rate Base:

Pros: The DSM costs are amortized in rates over a similar period for which the benefits of the DSM programs are expected to persist.

Rate volatility from varying levels of DSM spending is avoided. Please refer to the response to BCUC IR 1.10.2. The rate impact of the rate base approach is lower initially and is smoothed relative to the expensing approach. In addition, the present value of the revenue requirements from the rate base approach is lower for customers assuming customers have a time value of money preference based on a higher discount rate than the utility's after-tax cost of capital.

Cons: Effect of DSM spending on rates persists into the future with no related tangible assets on the Companies' books

Public Purpose Fund:

Pros: A public purpose fund provides a relatively straightforward and transparent means of raising funds for programs and activities considered worthy of such support.

Cons: A public purpose fund requires the establishment of a separate organization to administer the collection of funds and the carrying out of programs. This has the potential to become bureaucratic and will likely alter the utility-customer relationship in terms of the provision of DSM services. Please refer to the response to BCUC IR 1.43.2.4.4

Please note that, unlike in Oregon, there is no legislative basis for a Public Purpose Fund in British Columbia making this approach impractical. Please refer to the response to BCUC IR 43.2.4.4.

43.2.4.6 Please describe the currently approved DSM incentive mechanism used by Union Gas and Enbridge Gas Distribution in Ontario.

Response:

The OEB has mandated an incentive mechanism, the Shared Savings Mechanism ("SSM"). This incentive mechanism rewards the utility for success in DSM. The utility receives a portion of all societal benefits resulting from the DSM programs. The monies are collected from the customer and are later distributed to the shareholder.

The formula for determining the SSM payout is laid out in the OEB's decision EB 2006-0021. The table below illustrates the shape of the curve that determines the incentive amount paid out to each utility. As the utilities increase their Total Resource Costs ("TRC"[14]) benefits, they have achieved, the payout increases up to a maximum of $8.5 million. This amount will increase annually by the Ontario Consumer Price Index ("CPI") as determined in October of the preceding year (i.e., the 2008 cap will increase based on CPI at October 2007[15]). The indexing target used in the SSM calculation for 2007 for EGD is $150

[14] TRC test is a benefit-cost test which measures the net costs of a demand-side program as a resource option based on the total costs of the program. It is satisfied when the cost of energy saved through DSM is less than the cost of providing the same energy from new supply.
[15] http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf

million, and for Union Gas, $188 million. Targets for subsequent years are set according to a formula.

% of Annual Target achieved	**Payout**
Up to 25%	$225,000
Up to 50%	$675,000
Up to 75%	$2,250,000
Up to 100%	$4,750,000
Up to 125%	$7,250,000
Above 125%	$8,500,000 [1]

[1] Savings above 125% are capped at $8.5 million

Current regulatory settlements for both utilities span three years (2007 to 2009).

Please see the Companies response to BCUC IR 1.10.2.

65.0 Reference: Exhibit B-1, Appendix 1, CPR, DSM Incentive, p. E-xii

65.1 Please confirm that no DSM incentive will be applicable to the programs which may result from this application.

Response:

The EEC Application does not request a DSM incentive for the proposed Energy Efficiency and Conservation program areas outlined in the Application. Rather, the Companies are requesting Commission approval to treat all incremental EEC expenditures as equivalent to capital as outlined in Sections 1.4.2 and 6.12 of the Application. Please also see BCUC IR 1.10.2 for further discussion of capitalization.

29.0 Reference: Exhibit B-2, BCUC IR#1 43.2.4.6; and Exhibit B-1, Appendix 4, p. 29

The response to BCUC IR#1 43.2.4.6 states: "The OEB has mandated an incentive mechanism, the Shared Savings Mechanism ("SSM"). This incentive mechanism rewards the utility for success in DSM." The incentive is based on a sliding scale where higher performance is rewarded with a higher payout.

29.1 Do the Terasen Utilities consider the SSM as an acceptable incentive to align both shareholder and ratepayer interests in achieving the maximum TRC result for the DSM spend?

Response:

The Terasen Utilities believe that the appropriate treatment for the EEC expenditures is to capitalize the expenditures as described in section 6.12, p.80 of the Application (Exhibit B-1) and reiterated in BCUC IR#1 10.2. Further, as stated on p.81 of the Application, the Companies feel that setting a target on which an incentive would be paid out could prove to be challenging and contentious given the Companies have not previously established a target for energy savings from EEC expenditures.

Capitalization of EEC expenditures is also consistent with the Energy Conservation and Efficiency Policies outlined in the "The BC Energy Plan: A Vision for Clean Energy Leadership". Policy item #2 (Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia). The Terasen Utilities believe that the capitalization of the Companies' EEC expenditures would be consistent with the treatment approved for the two major electric utilities, BC Hydro and Fortis BC and would help the utilities develop a coordinated approach to energy conservation. Additionally, the accounting treatment proposed by the Companies will allow the Terasen Utilities to earn a return on the EEC expenditures, which is consistent with Section 60 (b)(ii) of the Utilities Commission *Act* that states:

> *"Provides to the public utility for which the rates is set a fair and reasonable return on any expenditure made by it to reduce energy demands"*

It is the understanding of the Companies that under the OEB mandated SSM, EEC expenditures are expensed in the year incurred and shareholders only receive an incentive in the event that program results exceed certain criteria. This means that shareholders do not necessarily earn a return on the expenditures made for energy efficiency and conservation programs. This result would be contrary to the Utilities Commission Act. Accordingly, the Companies are of the view that the SSM is not an acceptable incentive mechanism to align shareholder and ratepayer interests for utilities in British Columbia.

29.2 Would the SSM be better than capitalizing to rate base, in terms of aligning the shareholder incentive to maximize TRC results for the ultimate goal of energy conservation? Please discuss.

Response:

Please see response to BCUC IR 2.29.1.

29.3 If the Commission determined that an incentive mechanism would be a superior method of rewarding the utilities for promoting and undertaking cost-effective DSM, what form of incentive mechanism would the Companies propose? Please provide a detailed description of the type of mechanism.

Response:

The Companies are receptive to a mechanism that provides a fair return to shareholders and provides optimal benefit for its customers. The Companies are of the view that the financial treatment proposed in its Application is superior to an incentive mechanism, for the purposes of rewarding utilities in British Columbia for promoting and undertaking cost-effective EEC programs. For a further discussion, please refer to the response to BCUC IR 2.29.1.

As previously discussed, successful DSM will contribute to reduced demand and future expansion requirements and therefore restrict the Companies' ability to expand its business in the future. Incentive mechanisms are unlikely to provide the utility the same opportunity to generate additional future earnings consistent with system expansion. The Companies believe that the proposed capitalization of EEC expenditures helps to alleviate the dis-incentive that successful DSM programs could create.

However, in an attempt to be responsive to the hypothetical scenario set out in the question, the Companies are of the view that there may be some merit in an incentive mechanism similar to that approved for FortisBC (please refer to the response to BCUC IR 2.29.4 below), which allows for incentives over and above a return on its EEC expenditures.

29.4 FortisBC's current DSM incentive mechanism is described in Exhibit B-1, Appendix 4, at pages 8 and9. Please provide the results in terms of target and actual savings, target and actual costs, and incentive received, for the most recent five years available. Please comment on whether Terasen would consider such a mechanism to be acceptable in its case? If not, why not?

Response:

The results[17] in terms of target and actual savings, target and actual costs, and incentive received for the years 2002-2007 are listed below:

[17] Source: Email correspondence, Keith Veerman, PowerSense Department, FortisBC, August 2008.

To December 31, 2007; Energy Savings by Year (GW.h)

Year	Plan	Actual	% of Plan Achieved
2002	14.1	16.3	116%
2003	15.6	18.5	119%
2004	14.7	21.3	145%
2005	19	23.9	126%
2006	20.4	23.1	113%
2007	21.8	27.9	128%

Cumulative Fortis Costs

To December 31, 2007; Cost by Year ($000)

Year	Plan	Actual	% of Plan	$/MWh
2002	$ 1,661	$ 1,555	94%	95
2003	$ 1,840	$ 1,706	93%	92
2004	$ 1,814	$ 1,989	110%	93
2005	$ 1,835	$ 2,350	128%	98
2006	$ 2,234	$ 2,241	100%	97
2007	$ 2,474	$ 2,549	103%	91

DSM Incentive Earned

To December 31, 2007; Incentive by Year ($)

Year	Actual
2002	$ 61,810
2003	$ 69,000
2004	$ 58,000
2005	$ 99,000
2006	$ 76,400
2007	$ 119,500

As stated in the response to BCUC IR 2.29.3, the Companies are receptive to a mechanism that provides a fair return and provides optimal benefit for its customers. The Companies are of the view that the above noted mechanism contains components that may assist in meeting that goal. In the PowerSense model, EEC expenditures are treated as deferred expenditures. These deferred expenditures are factored into the rate base and FortisBC earns an approved rate of return over the approved amortization period. These earnings are in addition to any earnings that FortisBC might receive as an incentive as a result of the Shared Savings Mechanism (‘SSM”) that FortisBC currently uses.

As illustrated in the chart above, FortisBC has been successful in maximizing the resource savings acquisition per dollar spent and has received an incentive for each of the last 5 years.

29.5 The Performance Incentive Mechanism (PIM) and the Global Energy Efficiency plan Performance Incentive (GEEP) is described for Gaz Metro in Exhibit B-1, Appendix 4, at pages 20-22. Please comment on whether Terasen would consider such a mechanism to be acceptable in its case? If not, why not?

Response:

Under Gaz Metro's PIM, the utility receives an incentive based on the projected cost of service using a formula which includes consideration for the impact on volumes of energy efficiency measures. This incentive is based on a Reference Formula which allows Gaz Metro to retain a portion of the difference between the cost of service and the result obtained by applying the Reference Formula. If the costs of service exceed the result obtained by applying the Reference Formula, Gaz Metro has to either offset the difference or return a portion to the ratepayers.

The Reference Formula is based on the previous year's revenues plus inflation and adjustments for factors that affect volumes. One of these factors is the impact on volumes of energy efficiency measures. Gaz Metro receives compensation for 90 per cent of volume variations attributed to energy efficiency measures. Under the GEEP, Gaz Metro is tied to a targeted annual savings for a five year period. If Gaz Metro does not reach its goal in any one year, they do not receive a full yearly payout but a prorated incentive.

The Gaz Metro PIM and GEEP would not be an appropriate mechanism for the Companies to consider because under this plan, all EEC expenditures are expensed, and the shareholder may not necessarily earn a fair and reasonable return on its EEC expenditures.

29.6 Appendix 4 (page 29) of Exhibit B-1 states that the incentive mechanism in place "…ensures that program savings are real and verified and imposes penalties for sub-standard performance…."

Does Terasen support an approach that ensures that program savings are real and verified and imposes penalties for sub-standard performance? Why or why not?

Response:

The Companies support an approach that ensures that program savings are real and verified. To this end, the Companies have proposed a portfolio approach for the evaluation of its EEC programs. The Companies are seeking Commission approval for the overall incremental expenditures as outlined in Table 1.4.1 of the Application and have asked for the flexibility to redirect funds from one program area to another program area that the Companies believe will more readily meet the goals based on the assessment criteria outlined in the Application.

If the Companies receive Commission approval for the EEC spending levels as requested in the Application, cumulative annual savings in nominal (as opposed to present value) GJs is projected to result in savings reaching 6.4 million GJs by 2016. While this is a substantial savings, the Companies have not proposed an incentive based mechanism in its Application. The Companies believe that the optimum benefit for the ratepayer would be the approval of the Companies' proposed financial treatment. The Companies are of the view that imposition of penalties to shareholders will not result in greater alignment between shareholder and customer interest with respect to EEC expenditures. Additionally, any regime that included penalties for the Terasen Utilities would create a major difference between the programs of the Companies and the large electric utilities in the Province. This would not be appropriate in the opinion of the Companies.

Attachment 214.3

Your E Source Member Inquiry Response

Thank you for trusting E Source with your inquiry.

Answered by Melanie Wemple

Contributors: Adam Maxwell, Jesse Fife

Your inquiry:

How many (in number and percentage of surveyed) utilities subject their completed Evaluation and/or Measurement & Verification studies to additional third party review? Would this be considered standard industry practice, common industry practice, occasionally implemented or not reported?

For those utilities who do subject their completed Evaluation and/or M&V studies to additional third party review, what party implements and manages the third party review (examples might be: the utility offering the energy savings program, the utilities commission in that jurisdiction, a consultant or some other independent organization)?

For those utilities who do subject their completed Evaluation and/or M&V studies to additional third party review, what are the additional costs for this third party review in comparison to overall DSM spending?

Our response:

Based on our experience, it's not standard industry practice to subject an evaluation, measurement & verification study to additional third-party review. In ACEEE's 2012 report, National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs, this topic isn't even addressed—and this is the most comprehensive report on how evaluations are approached in the U.S. However, with such an urgent inquiry, it's difficult for us to determine whether it's "common practice" or implemented by only a few specific states. We found that it does happen in at least one province—Ontario—and three states—Maryland, Pennsylvania, and California. However, we weren't able to get any figures on the additional cost for this third-party review, or confirmation as to which entity pays for it.

In Ontario, the Ontario Power Authority told us it uses an internal EM&V department to review the third-party evaluations. This internal department is supposed to be arm's length from the internal operations of the programs.

In Maryland, the public service commission uses an Independent Evaluator (i.e., consulting firm) to verify the estimates of energy-efficiency program savings produced by the statewide evaluator (also a consulting firm) and recommend changes in estimates of program energy or peak savings where warranted. One example of Maryland's independent review can be found in the report Verification of Reported Program Impacts from 2011 EmPOWER Maryland Energy Efficiency Programs & Recommendations to Improve Future Evaluation Research (PDF).

Similarly, Pennsylvania utilizes a Statewide Evaluator (SWE) to conduct audit activities of utility programs in-conjunction with the utility's implementation and evaluation activities. The most recent audit, Program Year Four (2012-13) 3rd Quarter Report (PDF) summarizes SWE activities on PDF page 12. The following excerpt demonstrates their process:

> As part of the SWE audit activities, the members of the SWE team meet with each EDC [Electric Distribution Company] to review current program implementation and

evaluation activities and to address any pressing issues. Currently, the SWE team holds bi-weekly teleconferences with each EDC to discuss current and planned M&V activities, to schedule upcoming site-visits and audit activities, and to address any unresolved questions or issues that may arise throughout the evaluation process. During the current program year, the SWE team travels to each EDC and to specific project sites to conduct on-site audits of the various programs implemented in PY4. Additionally, the SWE team is in the process of conducting desktop audits for various programs.

In California, the Energy Division has overseen the energy-efficiency portfolios implemented by the IOUs since 2006. Prior to 2006, the IOUs evaluated the programs with limited oversight. The Energy Division releases an Annual Progress and Evaluation Report (PDF) that summarizes best available information from ongoing evaluations and studies conducted by consultants and in-house staff managed by IOU and Energy Division staff. According to the California Public Utilities Commission Energy-Efficiency Program Evaluation website, "the savings values included in this report were not verified through field research by the CPUC, although the impact studies that provide this verification are underway, the results of which will be included in 2013's annual report, expected in October 2013."

I hope you find this information useful. If you need any additional assistance, please e-mail Customer Service or call 1-800-ESOURCE.

Inquiry Number: 00022428

Attachment 215.1

Prism ENGINEERING

saving you energy

FORTIS BC™

ANALYSIS OF ENERGY SAVINGS FROM FORTIS BC EFFICIENT BOILER PROGRAM (EBP)

Project 2011008

Update August 5th, 2011

320 - 3605 Gilmore Way, Burnaby, BC V5G 4X5 main: 604 298 4858 toll free: 888 724 1715 prismengineering.com

Limits of Liability

This report was prepared by Prism Engineering Limited for FortisBC. The material in it reflects our professional judgement in light of the information available to us at the time of preparation. Without expressed written permission, any use which a third party makes of this report, or any reliance on or decisions to be made based on it, are the responsibility of such third parties. Prism Engineering Limited accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this report.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

APPENDICES

1. EXECUTIVE SUMMARY

This report summarizes the results from a historical billing analysis that has been used to quantify the savings associated with FortisBC's Efficient Boiler Program (EBP) conducted by Prism Engineering Limited (Prism).

In total, 135 sites are included in the study including 85 Multi-Unit Residential Buildings (MURB), 14 Office Buildings, 13 Schools and 23 buildings which were aggregated into the group “Other” as shown in the following figure.

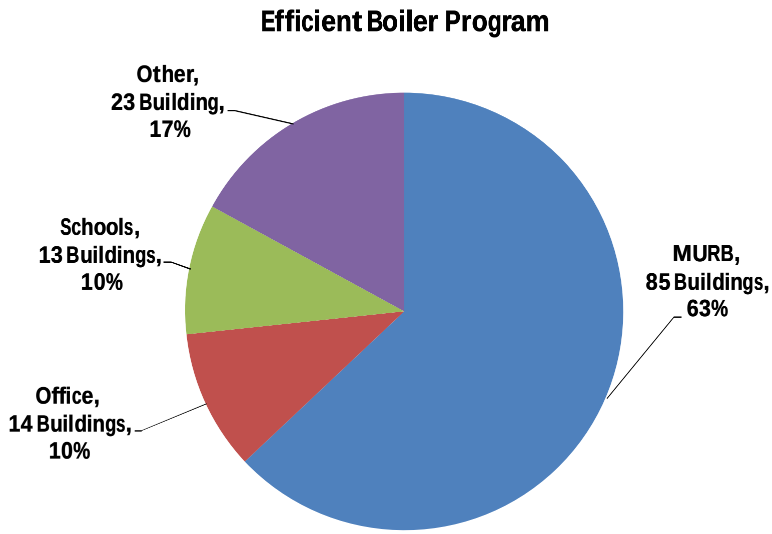


Figure 1: EBP Participant Breakdown by Building Type

The EBP estimates savings of 15% of pre-retrofit energy use and the results from this evaluation confirmed that this is an accurate overall projection. The average of the percentage savings in 2010[1] for the 131 sites was 16%. Through statistical analysis four sites were identified as outliers and excluded in this study.

Although the overall savings percentage was close to the EBP prediction, the range of results was significant. This analysis shows that savings are dependent on the building type, retrofitted boiler efficiency, other gas loads not impacted by the retrofit and whether or not other energy management measures were implemented along with the boiler replacement.

Multi-Unit Residential Buildings and School Buildings showed savings in 2010 which were above the overall average savings whereas Office Buildings and the buildings aggregated into the grouping “Other” showed savings below average as shown in the following figure.

[1] Although the projects were implemented between 2006 and 2009, 2010 was used to determine the savings for the program as all sites had at least one full year post retrofit.

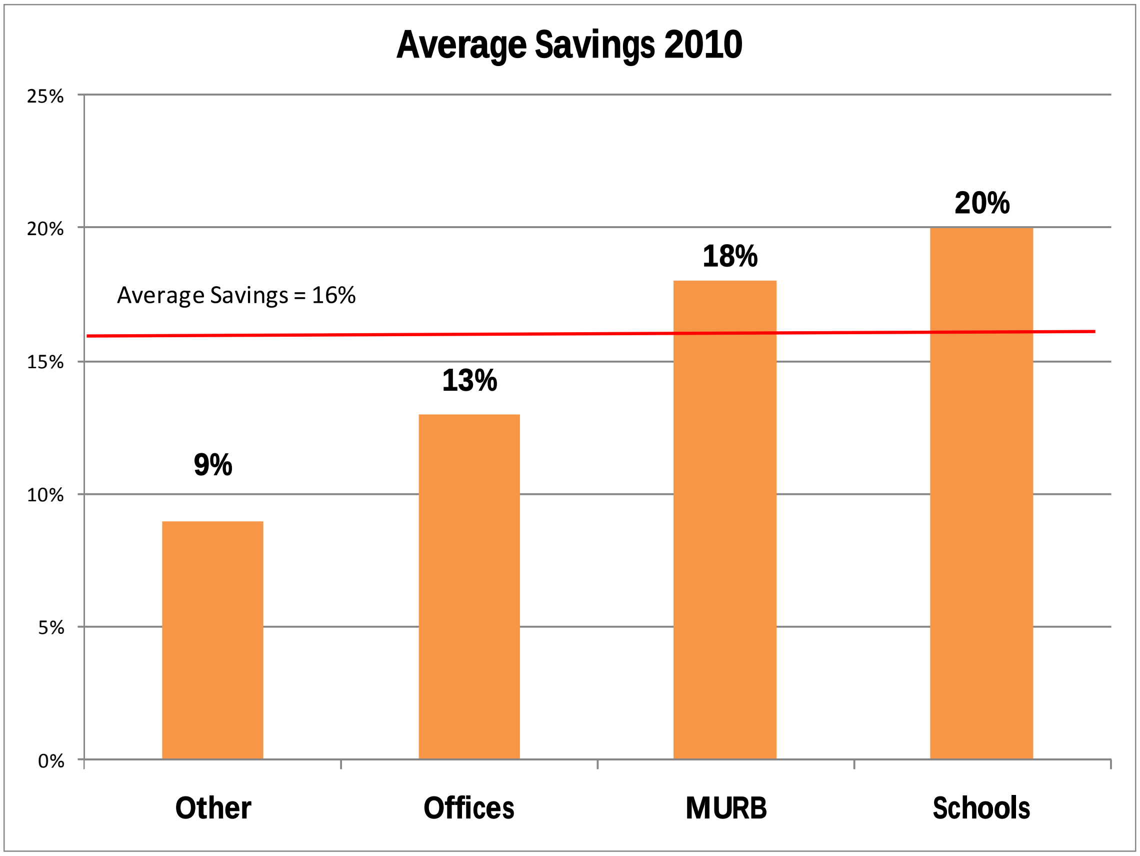


Figure 2: 2010 Savings Breakdown by Building Type

For the total set of building across all four building types the average savings and the median savings is 16%. The standard deviation for this analysis is 14% and the 95% confidence interval is from14% to 19%. This means that there is a 95% confidence that the savings will fall between 14% and 19%.

The boiler efficiency of the retrofitted boiler has an impact on the achieved savings. Sites with high efficiency boiler (efficiency ≥ 90%) achieved savings above average, whereas sites with mid efficiency boilers showed savings below average.

Furthermore it can be concluded that sites with a comprehensive retrofit at the same time as the boiler retrofit had achieved higher savings than sites which replaced the boiler only. The most common energy measures that occurred in addition to the boiler retrofit were upgrades of the building automation system and redesign of the HVAC system.

In 2010, the total energy savings from the 135 sites with at least one year post retrofit data were over 110,000 GJ. The cumulative savings from 2006 to February 2011 is just under 450,000 GJ.

2. BACKGROUND

2.1 Introduction

Prism Engineering Ltd. has carried out an analysis to quantify the savings associated with FortisBC's Efficient Boiler Program (EBP). The evaluation included 135 boiler upgrade projects and allows FortisBC to gain insights into the actual energy savings achieved from the program.

2.2 Scope

The scope of work for this project included the following:

1. Evaluate the energy savings resulting from the EBP, including total energy saved in GJ, energy saved in GJ per site (along with the average savings in %), actual vs. projected savings, and multi-year savings trends;
2. Carry out an analysis of the data segmented by boiler efficiency level such as mid vs. high efficiency;
3. Carry out an analysis of the data segmented by building type (MURB, office, school and other);
4. Review the boiler sizing (pre and post) to determine the percent oversized for both pre and post retrofit;
5. Where possible, carry out an assessment of the benefit of system changes (piping, pumping) that may have occurred at the same time as the boiler installation.

2.3 Limitations

The analysis has been carried out based on monthly utility data, information provided by FortisBC, and information collected through a phone survey of responsive applicants (details on sample group see 3.4). Site visits and detailed energy monitoring, both of which would increase the accuracy of the analysis, have not been included in this review.

3. METHODOLOGY

3.1 Overview

Prism used the following methodology to complete the savings analysis for this project:

1. Collected and imported data for each natural gas account provided;
2. Determined the appropriate balance point temperature for each meter (not standard 18°C balance point[2]);
3. Set up a baseline model of pre retrofit energy use using single variable linear regression (APPENDIX A for a summary of all models and APPENDIX B for the details of each model);
4. Calculated savings achieved annually post retrofit with weather adjustments: savings were calculated as the baseline adjusted for post retrofit periods weather conditions less the post retrofit energy use;
5. Determined if other measures were implemented at the same time and extensiveness of plant upgrade based on a survey to participants and phone follow-up;
6. Prepared Cumulative Sum (CUSUM) graphs to review the rate, seasonality and consistency of savings
7. Evaluated actual vs. projected savings (projections are based on FortisBC program estimate of 15% of pre retrofit energy use);
8. Carried out a statistical analysis of the savings results;
9. Consolidated results by sector and boiler efficiency type.

3.2 MT&R Software - Prism Utility Monitoring and Analysis (PUMA)

Prism has developed a database program for utility monitoring, targeting and reporting. This monitoring program:

- Minimized input time of electronic data transfer from FortisBC due to existing routines;
- Allows FortisBC to view "groups" of savings reports for various sectors;
- Includes innovative monitoring and targeting tools, such as CUSUM.

PUMA features an online interface for FortisBC to view utility monitoring and targeting reports. This web interface allows users to:

- Review trends regularly (monthly) without any software (beyond an internet browser)

[2] The balance point temperature characterizes the limit of the outside air temperature when heating is required. Depending on the building type and building construction the balance point temperature might vary which has an impact on the heating requirement of the building.

- Easily review consolidated or specific information – customizable reports.

FortisBC has been given online access to PUMA for this project for a period of six months and can view all accounts and the energy savings analysis carried out.

3.3 Data Provided by FortisBC

FortisBC has provided the following information:

1. Monthly gas consumption with reading date and days in electronic format with the last reading dates as shown in APPENDIX C;
2. Building information (type, sector, heated floor area, physical location);
3. Date of boiler installation;
4. Type of boiler installed (make, model, capacity, efficiency);
5. Survey results (provided through a third party).

Prism has treated all data as confidential.

3.4 Participants Survey

All 135 participants were asked to complete a 13 question phone based survey conducted by Justason Market Intelligence, a BC-based opinion research firm. 49 companies (36%) completed the survey. The survey questions are provided in APPENDIX D and the results are provided in APPENDIX **E** of this report.

Out of the 13 questions, the following two questions were particularly relevant for the interpretation of energy use analysis for the reasons identified below:

- Were any other energy management measures implemented at the same time as the boiler retrofit?
- What elements of this building are not impacted by the retrofit?

For the first question, we anticipated that savings may be higher if other measures were installed with the boiler retrofit which would INCREASE the reported savings from the project. Some of the sites carried out other retrofit measures such as installation of Building Automation System (BAS) or redesign of their HVAC system along with the boiler retrofit. This information is valuable as these sites might show energy savings above the average by taking advantage of a broader scope of retrofit.

For the second question, we anticipated that savings may be lower if other loads were in place using natural gas which would DECREASE the reported savings (from the perspective of an overall percentage) from the project. We asked to find out if there is any other natural gas equipment (ie kitchen equipment), or systems with separate boiler or other source of heat on site (ie gas fired rooftop units). This information is valuable as these sites might show energy savings below the average.

From the total number of survey results we identified 15 sites as outlier with available survey results and the permission to conduct a follow up call. 12 sites out of those 15 sites were contacted with the result that 7 sites responded and their feedback was incorporated in our analysis.

Table 1: Survey respondents and Follow – up phone calls

	MURB	**Office**	**School**	**Other**	**Total**
# Survey respondents	27	4	6	10	47
# Outlier with Survey respondents	8	2	3	2	15
# Outlier sites contacted	7	2	1	2	12
# Respondents	3	2	1	1	7

4. SURVEY

4.1 Survey results

Of the 135 program participants, 49 or 36% responded to the phone survey. 82% of the survey respondents were very satisfied with the program saying the application was easy, the process was simple and quick and that they were impressed with the fast approval rate. One customer commented that they were satisfied "because of strong personalized support." 16% were somewhat satisfied and 2% were very dissatisfied, citing difficulties with the application process.

The purpose of the survey was to collect site information on existing mechanical systems including any changes and operation practises to gain a better understanding of the individual savings. The program satisfaction was not part of the survey but recorded if any information was given by the applicants. The respondents who indicated that the application was easy were most likely with organizations which are experienced with boiler upgrades or retrofits.

According to respondents, if FortisBC had not offered the Efficient Boiler Program to the customers that participated in the survey, 69% would still have completed the retrofit, often due to old equipment needing upgrades. Those who would not have undertaken a retrofit project indicated that the "[FortisBC] incentives persuaded them to do it, [because otherwise] financial cost would have been a barrier."

Table 2: Summary of Survey Result Energy use

Retrofit scope	**only boilers**	**boiler & controls**	**other plant upgrades**	
	35%	45%	20%	
Other energy management measures	DDC control	redesign HVAC	Zone isolation	adding of insulation / heat recovery
	37%	24%	10%	10%
Elements not impacted by retrofit	roof top unit	domestic hot water	kitchen	other
	10%	10%	12%	5%
Operation and Maintenance costs	decrease	increase	no change	no information
	74%	2%	13%	11%

4.2 Savings Based on Survey Grouping

Table 3: Savings based on Survey Grouping

Survey group	Total	only boiler retrofit	including other measures	additional loads
# Sites[3]	47	17	30	17
Weighted Avg. Saving (2010)		13%	18%	11%

17 out of 47 sites that responded to the survey performed a boiler replacement only and these sites had an average savings of 13%. The sites which implemented other energy management measures along with the boiler retrofit such as control upgrades or redesign of HVAC system showed an average savings of 18%. Additional system upgrades are beneficial to optimize the operation of the boiler within the complete building system which results into higher savings than a boiler replacement only.

The sites with additional loads showed an average savings of 11 % which is lower than the overall average. It can be concluded that the additional loads impact the average savings but most of the sites with additional loads also had other energy management measures implemented which might have compensated some of the negative impact.

[3] Site A05 – 0005 is listed twice in survey result; Site A05 – 0009: utility data only until April 2007

5. ANALYSIS

5.1 Overall Energy Savings

For each meter, the energy savings were evaluated by comparing the pre and post retrofit data. A regression analysis was done on one year of data immediately prior to the boiler retrofit to identify the energy use model and dependence on weather[4]. This period is referred to as the “base period” and its trend of consumption as “baseline”. Energy use after the base period was compiled from the FortisBC billing system and then compared to baseline for evaluation of the savings.

Cumulatively, over 442,000 GJ savings was achieved for the 135 sites of the sample group by boiler upgrades through the EBP up to end of February 2011[5]. The average saving over 4 years from 2007 to 2010 is 14% as shown on the following figure and APPENDIX F.

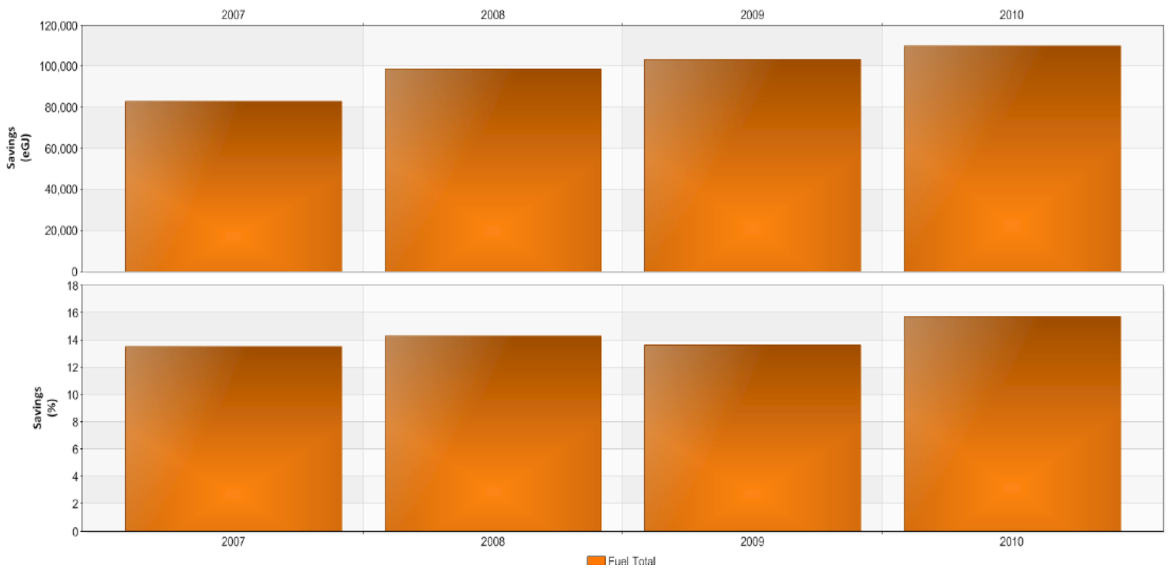


Figure 3: Four Year Summary of Energy Savings in GJ and Weighted Average Percentage

In 2010, the total saving for all studied sites was 110,000 GJ or 16% of baseline values. For the years 2007 to 2009 the savings results include the baseline year for some applicants. All applicants reviewed had a full year of savings by 2010. The 2010 savings is the highest of all four years because of the cumulative nature of the program. Note % is based on TOTAL GJ SAVINGS / TOTAL BASELINE ENERGY USE.

The accumulation of the savings is easily determinable using a Cumulative Sum (CUSUM) graph. CUSUM is an analysis technique employed to understand and quantify changes in energy usage and the trends in performance. The difference in energy use between actual and target is calculated for each period and added together,

[4] In two cases, the baseline period selected was not the twelve months prior to the retrofit. A05-0054 (745 days), A05 – 219 (not the year before retrofit)

[5] The majority of sites have data to the end of February 2011. Some sites only have data to November 2010 to January 2011.

creating a "running total." This is referred to as the CUSUM, or Cumulative Sum, of the differences. The CUSUM is also referred to as the cumulative savings total and is calculated using the base period for each meter and adding the savings for each site. Trends in the CUSUM graph indicate consumption patterns.

When there have been changes in energy use, the CUSUM will deviate from the horizontal and slope upward over periods of reduced energy usage and downward over periods of increased usage. The steeper the slope, either upward or downward, the greater the deviation in energy use from that in the base period. As more projects were added to the EBP over time, it is expected that the rate of savings from the program as shown by the slope of the CUSUM graph would increase.

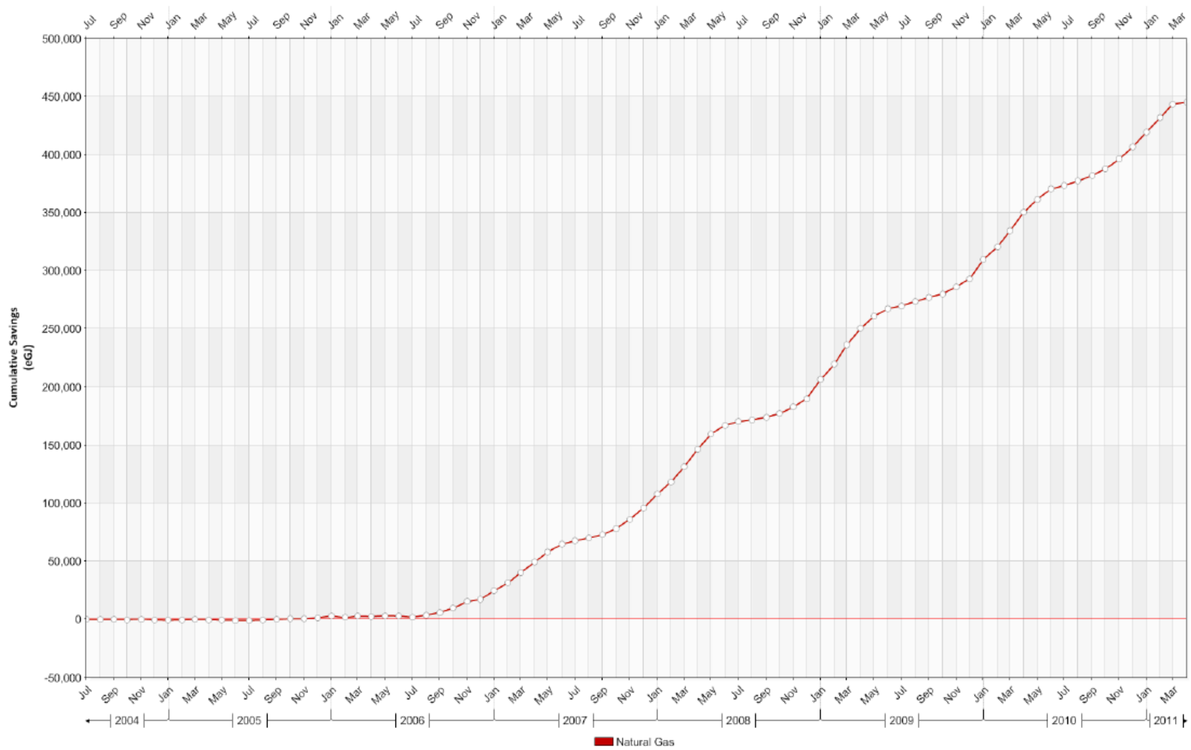


Figure 4: Combined Cumulative Savings for All Studied Sites in EBP Analysis

The CUSUM over the entire project (including all studied applicants) is shown above and in APPENDIX G demonstrates that significant savings were achieved from 2006 to 2010 from the EBP. Savings were achieved during heating and non heating periods with steeper incline in savings during the heating seasons. The CUSUM for each site are shown in APPENDIX H (available as a separate attachment due to file size).

As shown by the following graph of all studied sites, energy savings in 2010 ranged from +61% to -226% for the 135 sites. Approximately 50% of the sites have savings between 10 and 30%. Although individual sites are not identified in this overview, results for each site are presented later in this report in section 5.2.

The average savings can be calculated by using two different methods:

- Average of the percentage savings of all studied sites which does not account for the magnitude of savings. This figure is an arithmetic average based on the number of sites and might be of interest for analysis solely based on number of buildings.

- Weighted average saving which is based on the total consumption saving for all studied sites compared to the total baseline energy use for all studied sites. This figure accounts for the magnitude of savings of the individual sites and evens out outlier results of smaller sites.

For all studied sites in 2010, the average of the percentage savings was 14% and the weighted average saving for was 16% and shown in the graph and APPENDIX I.

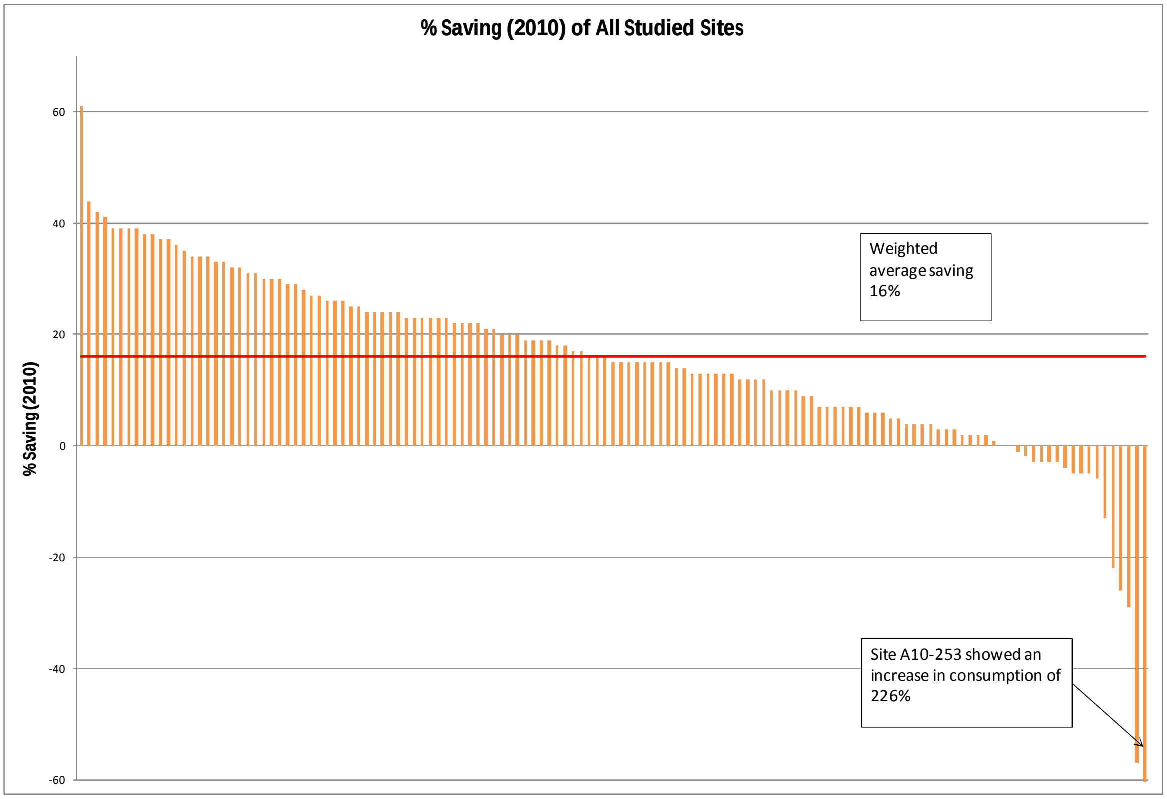


Figure 5: Energy Savings in Percentage for Each Studied Sites

The graph demonstrates the range of savings that have been determined. The reasons for this wide variance are discussed on a sector by sector basis in the next sections.

5.2 Energy Analysis by Building Type

To identify if energy savings was dependent on the type of building use, an energy use analysis by building type has been carried out for Multi Unit Residential Buildings (MURB), Office and School Buildings. The remaining building types are very diverse and appear in limited number within the scope of studied sites. The sample sizes for the remaining building types would have been too small for any analysis. Therefore we have aggregated the remaining 23 sites into a combined group called “Other”. The following sections review the results of each of these building categories and the results can be found in APPENDIX J and APPENDIX K.

For each building type an evaluation of the average savings was performed and site specific analysis for sites with unexpectedly high savings or increase of consumption. A statistical analysis was performed to determine the mean, median, standard deviation and confidence interval:

- Mean, which is the average value representing the centre of gravity of the distribution and is also referred to as average saving;
- Median, which is the middle value above which, and below which, 50% of the values are located.

The spread and dispersion of the energy savings are expressed by the standard deviation and confidence interval.

- Standard Deviation, is a measure of the typical or average distance from each value to the mean;
- Confidence interval, which provides an interval of a upper and lower limit of savings and the confidence level with which the actual savings will fall between the upper and lower limit.

Note that the standard deviation and confidence interval are highly sensitive to outliers. Therefore, the statistical analysis determined the outliers and the savings per building type in the subsequent section was performed excluding 4 sites which were identified as outliers.

For the total set of buildings across all four building types with four outliers removed, the mean and median energy savings are both 16%. The standard deviation is 14% and the 95% confidence interval is (14%, 19%). The values for each building types are shown in the summary table for each building type and the detailed statistical analysis is attached in the APPENDIX M.

Multi Unit Residential Buildings

Table 4: MURB Summary Energy Analysis

Number of sites(*)	84			
Average Saving 2010 (average of the savings in % of all sites)	18%			
Weighted Average Savings 2010 (total savings for all sites compared to the total baseline energy use for all sites)	17%			
# of Sites with savings between following savings range	> 30%	10% to 30%	0% to 10%	< 0%
	12	51	15	6
Standard deviation	12%			
95% Confidence interval	15.5%, 20.7%			
Number of survey respondents	27			

(*) outliers excluded

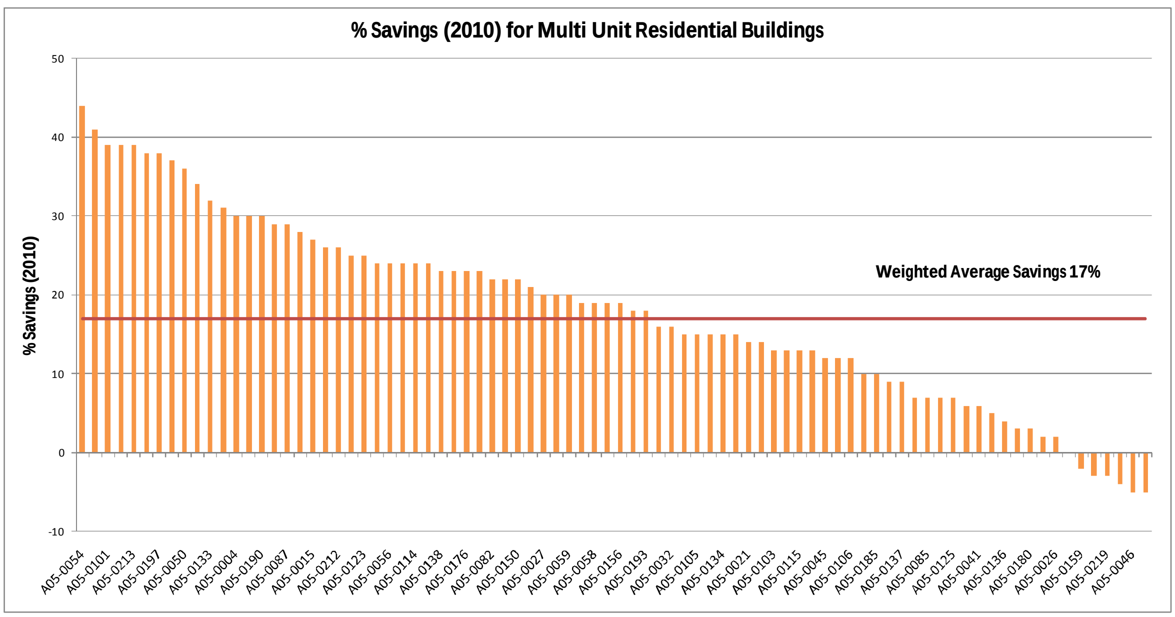


Figure 6: MURB, % Savings 2010

The bulk part of the MURB sites fall within the category of 10% to 30% savings with an average of 18% savings within this group. 12 sites are performing well above the average with the top performer showing savings up to 44%. The top performing sites show similar characteristic in terms of cumulative savings with persistent savings over multiple years after installation of the efficient boiler(s).

22 sites perform below average with 6 sites showing an increase in consumption and two of these sites have provided a response through the survey. A follow up call was conducted with both sites with the following result:

- Site A05 – 0069: Contact information was incorrect and no further information could be provided;
- Site A05 – 0020: The client confirmed the data from the survey and provided the information that no change in operation took place after the boiler retrofit. Furthermore she mentioned that the installed boiler did not operate reliably after installation and the contractor who installed the boiler had to come in several times. The client expresses her dissatisfaction with the retrofitted boiler due to the reliability problems of the retrofitted boiler. It can be concluded that the replacement process of the boiler was not optimal but no conclusion can be made regarding the increase in consumption.

Detailed analysis of specific sites:

The sites chosen for the detailed analysis are either sites with unexpectedly high savings or increase of consumption. Survey results were summarized for the respective site if available.

Table 5: MURB Detailed Analysis Specific Sites

A05 – 0054	Category > 30 % saving: The top performing site achieved savings of 44% but the client did not participate in the survey.
A05 – 0080	Category > 30 % saving: The site achieved savings of 41% and the client provided the information that the control upgrades were implemented along with the boiler retrofit.
A05 – 0005 A05 – 0177	Category > 30 % saving: Control improvements and redesign on the HVAC system had been carried out along with the boiler retrofit. The comprehensive retrofit might be the reason that these two sites achieved above average savings.
A05 – 0069	Category < 0% saving The cumulative saving analysis shows a persistent increase in gas consumption after the boiler replacement. The boiler replacement was carried out along with controls upgrade and redesign of the HVAC system. There is no obvious explanation for the increase of the consumption as no other loads were specified in the survey.

Offices Buildings

Table 6: Office Buildings Summary Energy Analysis

Number of sites	14			
Average Saving 2010 (average of the savings in % of all sites)	13%			
Weighted Average Savings 2010 (total savings for all sites compared to the total baseline energy use for all sites)	7%			
	14 %		13% ± 7.37%	
# of Sites with savings between following savings range	> 30%	10%to 30%	0% to10%	< 0%
	3	3	6	2
Standard deviation	14.1%			
95% Confidence interval	4.7%, 20.9%			
Number of survey respondents	4			

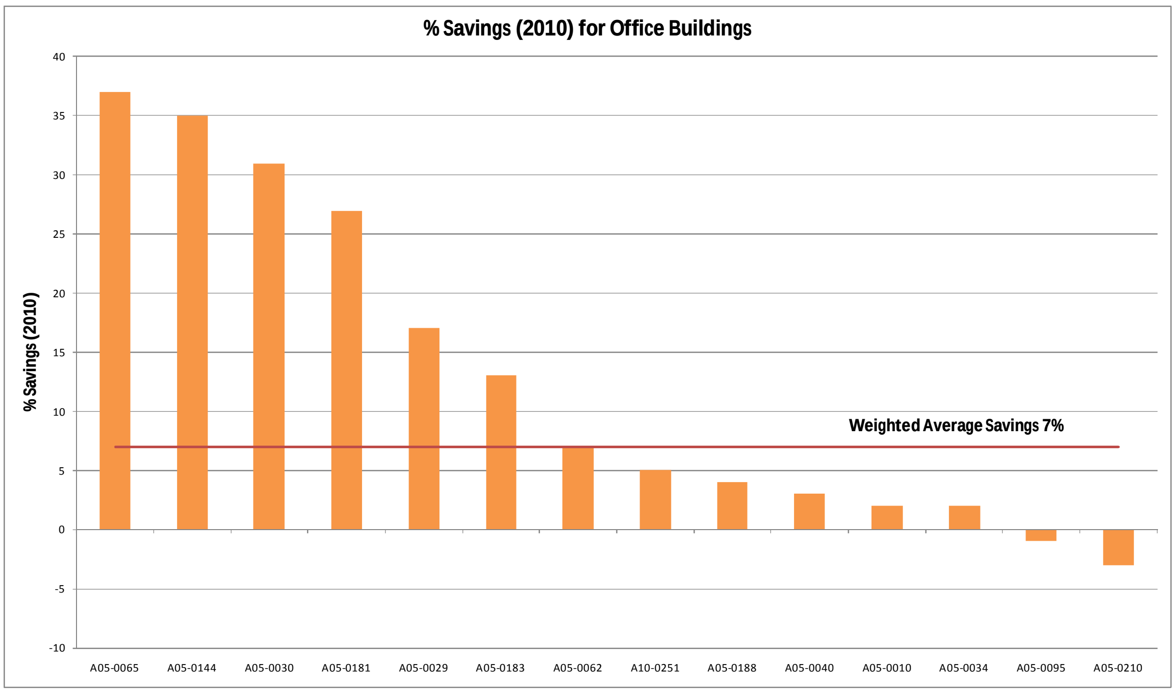


Figure 7: Office buildings, % Savings 2010

The office buildings showed a wide range of achieved savings for 2010 from 37% to -3%. Three sites with the highest savings in 2010 showed that savings were achieved immediately after the boiler retrofit and remained persistent over the entire period. The bulk part of the sites (6) achieved savings between 0% and 10% and only one site within this group participated in the survey.

Two sites had an increase in consumption with the worst performer showing an increase of 3%. Site A05 - 0095 which had an increase in consumption of 1% was followed up through a phone call. The CUSUM analysis for this site shows a significant change in consumption in November 2008 and the client was asked if any changes of operation happed during that particular time period. The client responded that no major changes of the building or operation were performed after the boiler installation.

Detailed analysis of specific sites:

The sites chosen for the detailed analysis are either sites with unexpectedly high savings or increase of consumption. Survey results were summarized for the respective site if available.

Table 7: Office Buildings Detailed Analysis Specific Sites

A05 – 0065	Category > 30 % saving: The top performing site achieved savings of 37% and the CUSUM shows that savings were achieved immediately after the boiler replacement. The client did not participate in the survey.
A05 – 0095	Category < 0 % saving: This site showed that savings were achieved after the boiler installation which did not remain persistent as the consumption started to increase about a year later. As discussed earlier the client did not provide any information which could have explained the change.
A05 – 0210	Category < 0 % saving: This site showed seasonal savings with savings achieved during the heating season only. During the non heating season the consumption increased which resulted into a net increase of 3% in consumption in 2010. The client provided the information that the building automation system has been upgraded along with the boiler retrofit measure. That indicates that the boiler plant does not operate efficiently during partial loads.

School Buildings

Table 8: School Buildings Summary Energy Analysis

Number of sites(*)	12			
Average Saving 2010 (average of the savings in % of all sites)	20%			
Weighted Average Savings 2010 (total savings for all sites compared to the total baseline energy use for all sites)	18%			
# of Sites with savings between following savings range	> 30%	10% to 30%	0% to10%	< 0%
	5	5	0	2
Standard deviation	16.2%			
95% Confidence interval	10.0%, 30.6%			
Number of survey respondents	6			

(*) outliers excluded

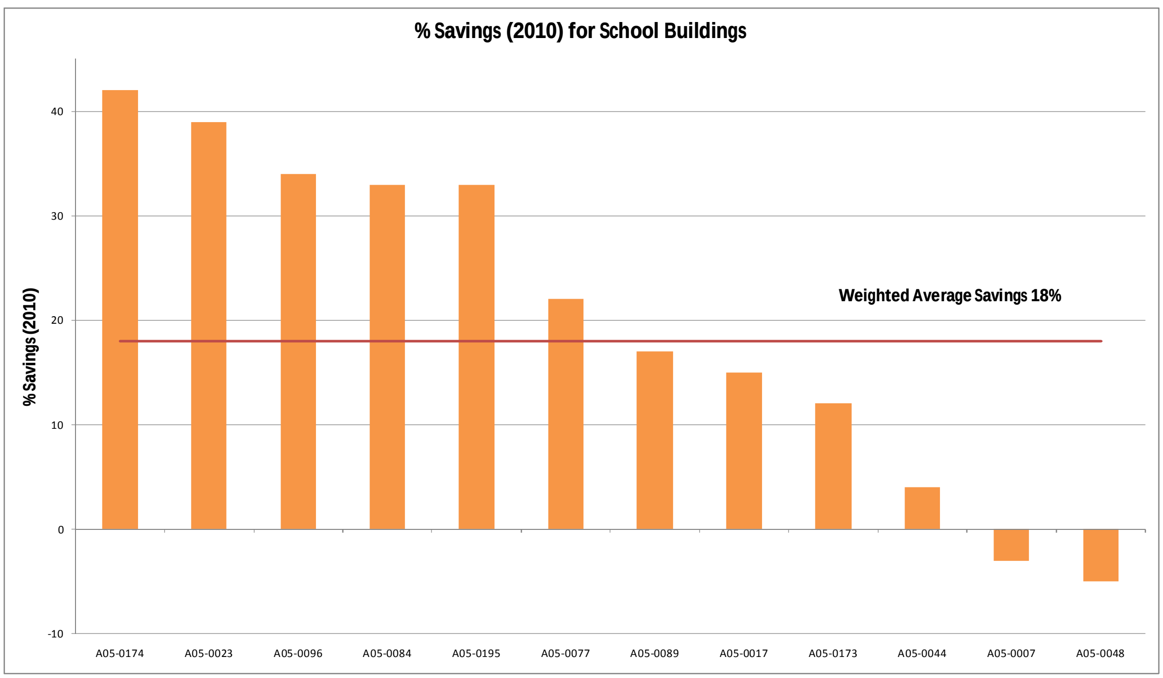


Figure 8: School Buildings, % Savings 2010

The top five school buildings achieved savings significantly above the overall average and 3 out of these sites also provided a survey feedback. The 5 schools within the midrange of savings achieved an average saving of 14%.

Two school buildings showed an increase in consumption with an increase of 5% of the worst performer.

Detailed analysis of specific sites:

The sites chosen for the detailed analysis are either sites with unexpectedly high savings or increase of consumption. Survey results were summarized for the respective site if available.

Table 9: School Buildings Detailed Analysis Specific Sites

A05 – 0174	Category > 30 % saving: The top performing site achieved savings of 42% and the client provided the information that no other energy savings measures were implemented along with the boiler retrofit.
A05 – 0023	Category > 30 % saving: The site with the second highest achieved savings of 39% provided the information that a building automation system was implemented along with the boiler retrofit.

Other Buildings Types

This “Other” category aggregates the results of the following building types: Housing, Care Homes, Church, Culture Center, Firehalls, Recreational Buildings, Hospital, Hotels, Greenhouses and Shopping Centre.

Table 10: Other Building Types Summary Energy Analysis

Number of sites(*)	21			
Average Saving 2010 (average of the savings in % of all sites)	9%			
Weighted Average Savings 2010 (total savings for all sites compared to the total baseline energy use for all sites)	11%			
# of Sites with savings between following savings range	> 30%	10%to 30%	0% to10%	< 0%
	2	8	7	4
Standard deviation	16.2%			
95% Confidence interval	10.0%, 30.6%			
Number of survey respondents	10			

(*) outliers excluded

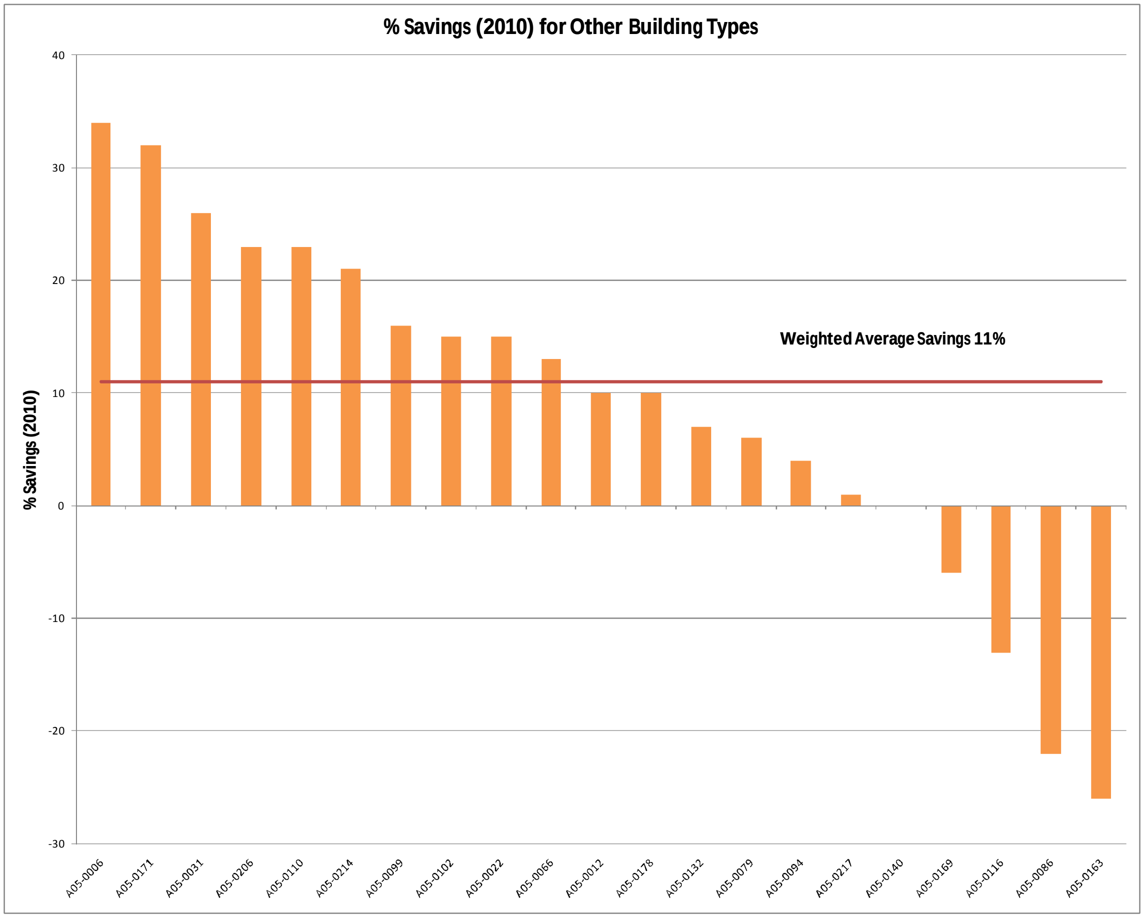


Figure 9: Other Building Types, % Savings 2010

The top two performing sites with savings over 30% are a hotel, and a housing building. The majority of sites achieved savings between 10% and 30% which includes 2 sites where other energy management measures were implemented besides the boiler installation. From the 4 sites with negative savings 3 sites provided survey responds.

Detailed analysis of specific sites:

The sites chosen for the detailed analysis are either sites with unexpectedly high savings or increase of consumption. Survey results were summarized for the respective site if available.

Table 11: Other Buildings Detailed Analysis Specific Sites

A05 – 0024	Category > 30 % saving: The top performing site is a greenhouse which achieved savings of 61% and the client did not participate in the survey. From the history of energy use it can be seen that the consumption was significant reduced after the boiler retrofit.
A05 – 0086	Category < 0 % saving: Site A05-0086 never achieved any savings after the boiler retrofit and had an increase in consumption of 22% by 2010. The client provided the information that the boiler retrofit was the only measure which was implemented but a roof top unit is operating on site which could explain the increase in consumption.

5.3 Energy Analysis by Boiler Efficiency Levels

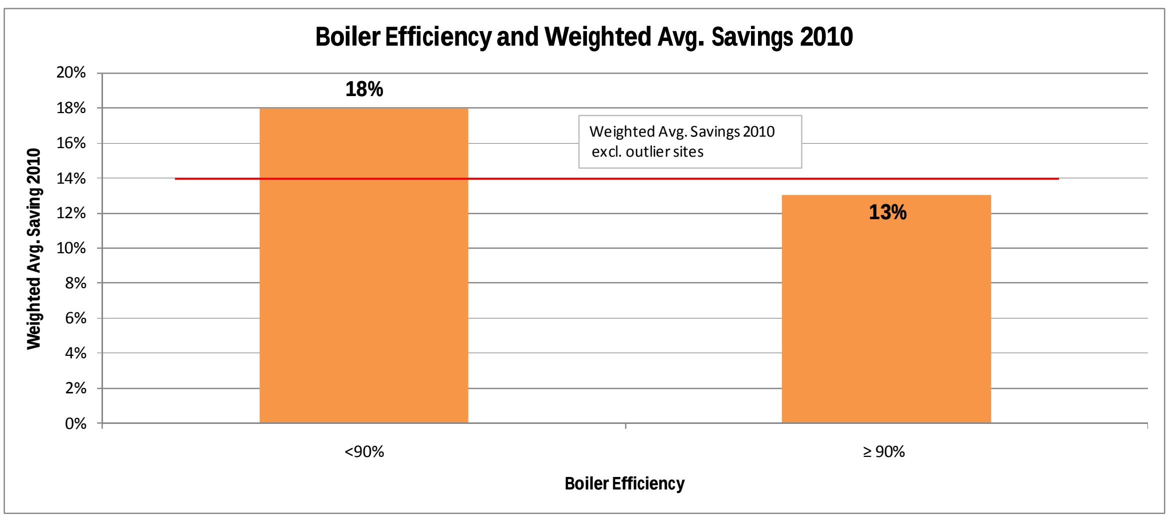
Analysis of the energy data segmented by boiler efficiency level was performed to identify the average savings of each. 131 sites are included in this analysis which represents the complete scope of all studied sites excluding the outliers. The achieved savings for 2010 of the all studied sites were considered for this analysis and shown in APPENDIX L.

Table 12: Energy Analysis by Boiler Efficiency Category

	High efficiency boiler (≥ 90%)	**Mid efficiency boiler (< 90%)**	**All studied sites excluding outliers**
Sample size	63(*)	68	131
Weighted Average Savings 2010	18%	13%	14%

(*) outliers excluded

As shown in the table above it can be concluded that the sites with high efficiency boilers achieved above average savings and higher savings than sites operating mid efficiency boilers. Furthermore, it can be seen that sites with mid efficiency boilers achieved savings slightly below the overall weighted average of all studied sites.



5.4 Boiler Sizing Review

A review of boiler sizing was performed for post retrofit conditions using the installed boiler capacity for the retrofitted boiler. A pre retrofit analysis was not performed due to lack of data of the installed capacity prior to the retrofit. The goal for this analysis was to estimate the oversized percentage of the new boilers.

Methodology

1. Baseline period for post retrofit condition
   - 2010 was set as baseline period for the analysis as the retrofit activities were completed for all studied sites prior to 2010;
   - Regression analysis[6] was used to model each meter's energy use and its correlation to weather.
2. Determined the design heating load to ensure adequate sizing of the boiler based on an estimated occupancy load for each sector
3. A total of 106 accounts were considered for this analysis as 29 sites were excluded from this analysis
   - 10 accounts with partial missing data for 2010;
   - 11 accounts did not show a weather sensitivity for 2010;
   - 8 accounts with the "Other" grouping due to missing information on their operation.
4. Determined the load factor for each site. The load factor represents the design heating load to the installed boiler capacity.

[6] A regression analysis is a statistical method of determining dependency of natural gas consumption to the weather expressed in heating degree days.

The results are summarized in the following table:

Table 13: Boiler Sizing Results

Load Factor	**Number of Sites**
<0.5	23
>0.5 to 0.7	42
>0.7 to 1.3	35
>1.3	8

A load factor of < 0.5 indicates that the installed boiler capacity is much higher than (more than twice) the design heating load. 16 out of 23 sites are residential sites.

The majority of the sites are within the classification > 0.5 to 0.7. To determine if the installed boiler capacity is reasonable an analysis on a by-case basis would have to be performed. For instance some sites operate a boiler plant with more than one boiler to guarantee operation in case one of the boilers fails. The installed boiler capacity would have to be assessed based on requirements on the boiler plant and the site operation requirements.

A significant portion of the sites fall within the range > 0.7 and 1.3 which would suggest that the installed boiler capacity is reasonable. This judgement would have to be verified on a by-case basis for the same reasons as discussed earlier.

Sites which fall under the last category of > 1.3 indicate that, most probably, other gas consuming equipments are operating on site. This can be confirmed for 2 sites as their survey results show that other gas consuming equipment are operating on site such as a gas fired roof top unit. Note that the weighted average savings for 2010 of this group of sites is 6% which is significantly below the overall average and confirms that other natural gas consuming equipment is operating on site.

5.5 Assessments of System Changes Benefits (Survey Participants Only)

The conducted survey provided following information regarding the scope of additional system changes of the different sites.

- Sites which carried out the boiler retrofit only;
- Control upgrades along with the boiler retrofit including redesign of the HVAC system, Zone isolation and DDC modifications for some of those sites;
- Other plant upgrades were carried out along with the boiler retrofit such as piping and distribution upgrade and most of these sites also performed modification on their DDC system.

Sites which had implemented other energy management measures along with the boiler showed a weighted average savings of 18% whereas sites which had only replaced the boiler showed an average savings of 13% with details shown in Appendix N.

It can be concluded that sites with other energy management measures additional to the boiler retrofit generally achieve higher savings than sites with boiler retrofit only.

Boiler Replacement Including Other Energy Management Measures

Table 14: Survey Result Boiler Replacement Including Other Energy Management Measures

Number of sites	28			
Average Saving 2010 (average of the savings in % of all sites)	18%			
Weighted Average Savings 2010 (total savings for all sites compared to the total baseline energy use for all sites)	18%			
# of Sites with savings between following savings range	> 30%	10% to 30%	0%to10 %	< 0%
	5	14	7	2

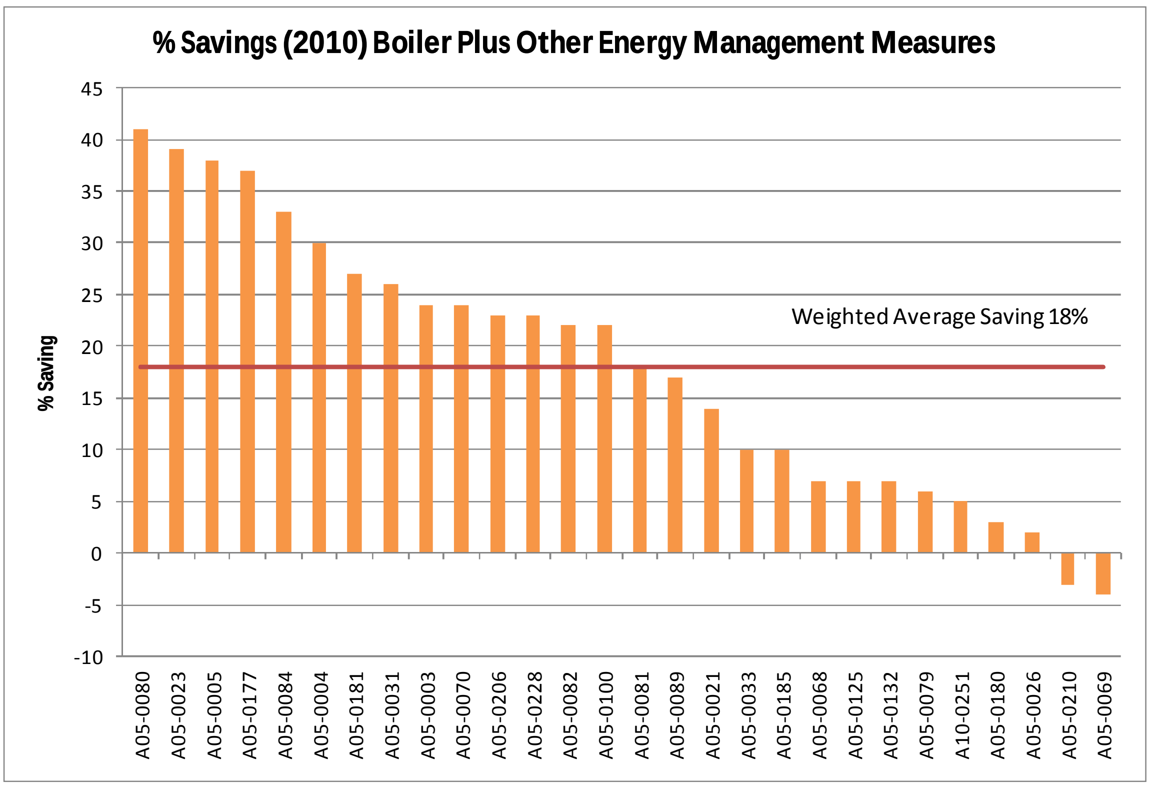


Figure 10: Boiler Retrofit including Other Energy Management Measures, % Savings 2010

Among the five sites with savings over 30% savings are three MURB and two school buildings with a MURB building as top performing site with 41% savings. The majority of the sites are MURB's which fall into the category of 10% to 30% savings.

The worst performing sites are a office building and a MURB building with -3% and -4% savings respectively.

Boiler Replacement Only

Table 15: Survey Result Boiler Replacement Only

Number of sites	17			
Average Saving 2010 (average of the savings in % of all sites)	16%			
Weighted Average Savings 2010 (total savings for all sites compared to the total baseline energy use for all sites)	15%			
# of Sites with savings between following savings range	> 30%	10%to 30%	0% to10%	< 0%
	4	8	1	3

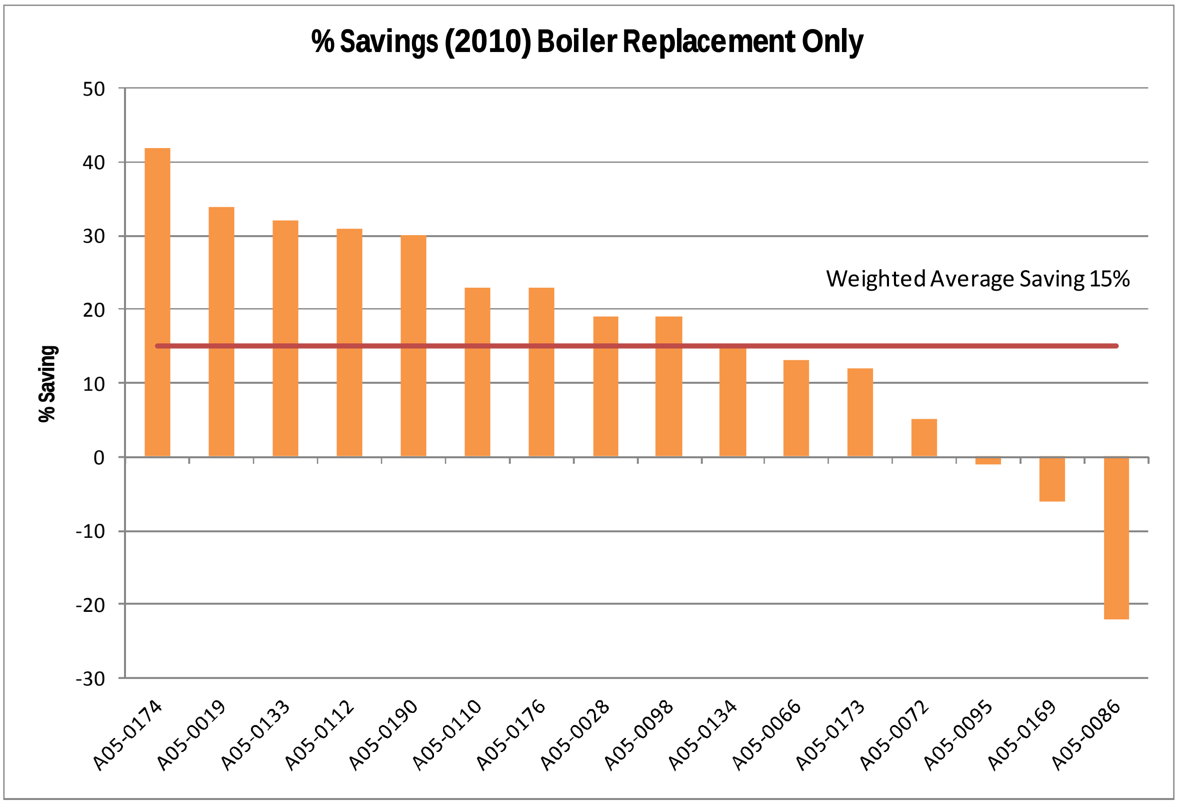


Figure 11: Boiler Retrofit Boiler Replacement Only, % Savings 2010

Among the sites with savings over 30% savings are two MURB, one office building and a school building which is the top performing site with 42% savings. The majority of the sites fall into the category of 10% to 30% savings with mostly MURB buildings.

The worst performer is a Shopping center which had an increase in consumption of 22% in 2010.

5.6 Assessment of Sites with Equipment not Impacted by the Boiler Retrofit (Survey Participants Only)

Table 16: Survey Result Systems not impacted by the Boiler Retrofit

Number of sites	16			
Average Saving 2010 (average of the savings in % of all sites)	17%			
Weighted Average Savings 2010 (total savings for all sites compared to the total baseline energy use for all sites)	13%			
# of Sites with savings between following savings range	> 30%	10% to 30%	0% to 10%	< 0%
	3	8	4	1

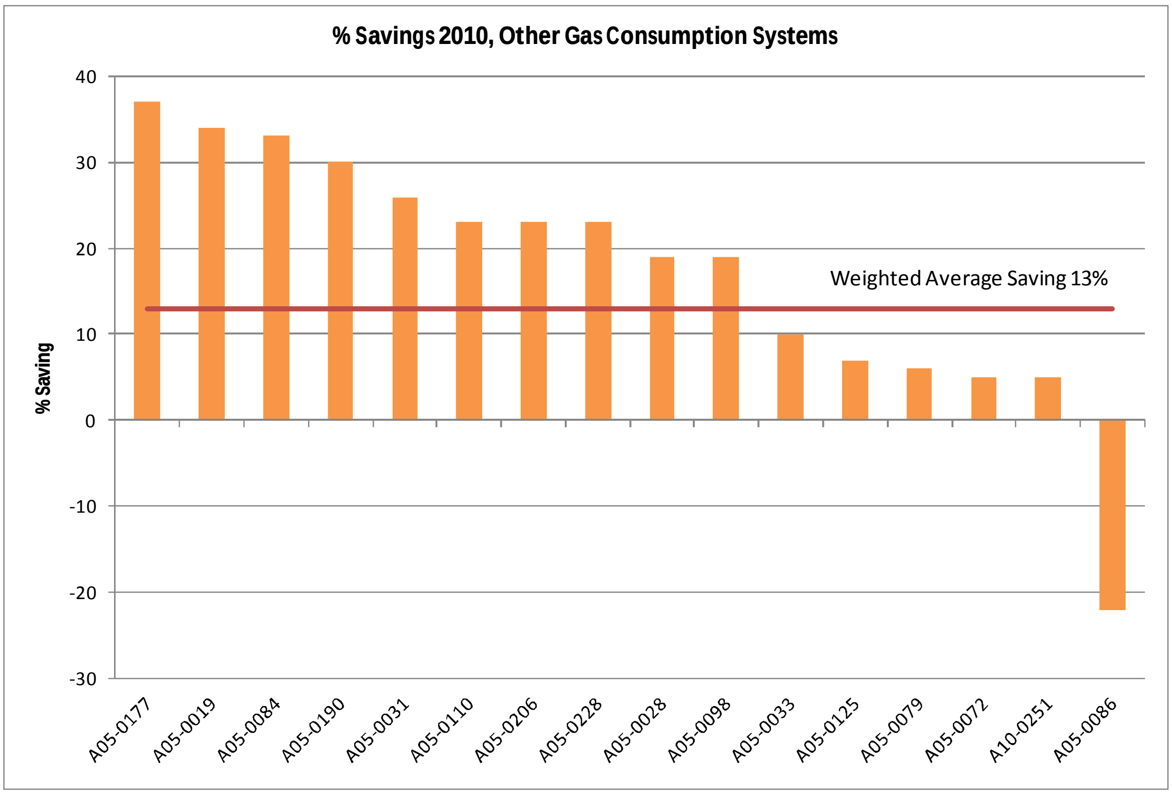


Figure 12: Sites with Result Systems not impacted by the Boiler Retrofit, % Savings 2010

Some of the sites which participated in the survey indicated that other natural gas consuming equipment is operating on site besides the boiler. In some cases an increase in natural gas consumption can be related to an increased in operation of these other units. The survey showed that six sites have additional gas consumption through kitchens and five sites operate gas fired roof top units.

The survey showed that 8 sites had performed the boiler retrofit only and also stated additional loads such as kitchen use and gas fired roof top units. The weighted average savings for 2010 of this group is 13% which is lower than the average of the group as discussed earlier. This indicates that the additional energy management measures partly compensate the increase in consumption for these sites.

6. RECOMMENDATIONS

6.1 Measurement and Verification

M&V of the savings from boiler retrofits is difficult to carry out using utility bill analysis in the following scenarios

- Other measures implemented at the same time;
- Other loads that are not impacted by the boiler retrofit.

It is recommended to establish a questionnaire to collect site specific information such as operation profile, basic information of installed mechanical system and other gas consuming equipment on site. This questionnaire should be a mandatory document which has to be filled out by the applicant along with the application for the Efficient Boiler Program. This would make future M&V analysis easier as results could be related to site specific circumstances especially for buildings which don't fall into the main categories.

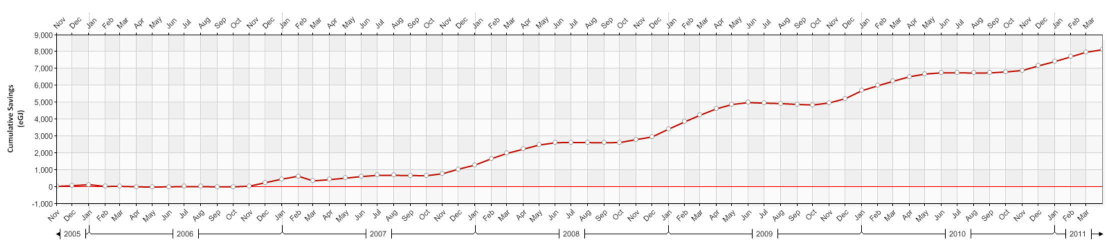
6.2 Sizing Boiler Plants

Approximately 20% of the sites had installed capacity 2x larger than what post retrofit consumption is indicating as required. If FortisBC provides incentives base on the installed capacity, they may consider the impact of boiler oversizing on incentive amounts.

6.3 Persistency of Savings

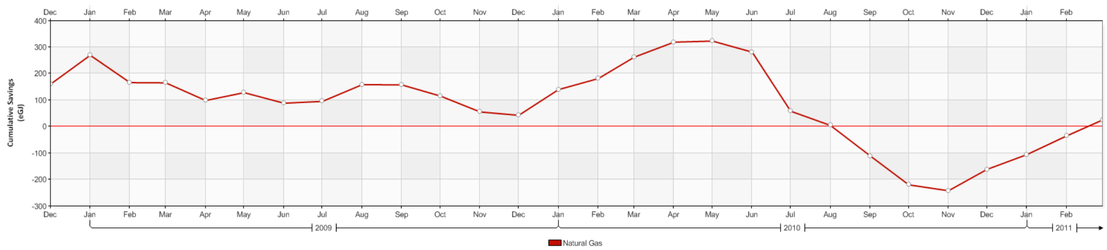
The different characteristic of savings is discussed using the CUSUM analysis and recommendations are developed for commonly observed consumption trends.

- Trend 1: Persistence savings
  Significant savings were achieved by sites which showed persistent savings over multiple years. It can be seen that slope is the steepest during the heating season when the actual savings are achieved. It is recommended to discuss the implementation and operation strategies with these sites to learn from their success.

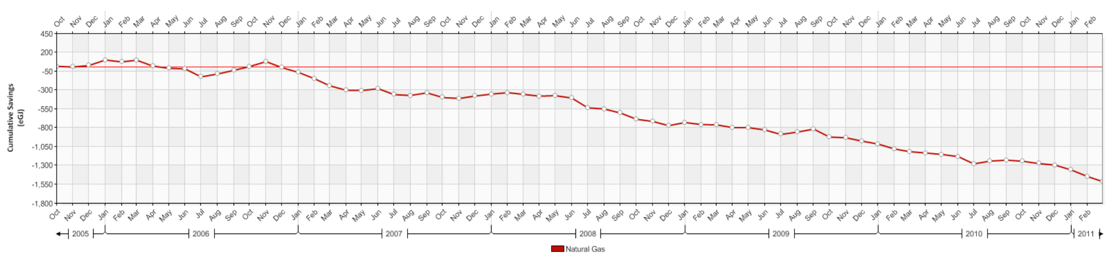


- Trend 2: Seasonal savings
  This consumption trend was observed for approximately 5 sites with different magnitudes in the change of consumption trends.

  This trend is characterized by savings achieved during the heating season (upward slope of the CUSUM) and increased consumption during the non heating season (downward slope of the CUSUM). This characteristic indicates that the boiler operates inefficient at partial load resulting into low or even negative savings over the entire period. It is recommended that further investigation should be carried out for sites showing seasonal savings to achieve persistent savings.



- Trend 3: Persistence increase of consumptions
  Some sites show a persistent increase of consumption after the boiler retrofit which can be seen by the constant downward slope of the CUSUM. Reasons for showing such a characteristic could be either related to increased loads, such as an increase in operation hours or a result of improper boiler operation. It is recommended to conduct further investigations at sites showing such a characteristic to achieve savings where the operation conditions remained the same and savings are not achieved.



6.4 Tracking savings ongoing

Now that all account baselines and grouping have been set up in PUMA and available online, FortisBC may wish to continue to use MT&R with PUMA as a part of the EBP to track and verify savings on an annual basis.

APPENDIX A: Base Period Summary

Base Period Summary

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter				Base Period			Category			Analysis						
Name	Weather Station	Name	Description	Premise ID	Account Number	Start	End	Days	Category	Actual	Baseline	Type	Base Load	B.P.T	Weather Factor	Degree Days	Weather Component	R2
A05-0003	Vancouver	GAS-0003	Install Date: 09/09/2005	406662	1178691	2004-09-01	2005-08-31	365	Consumption	4,807 GJ	4,806 GJ	Heating	5.09 GJ	18.00 °C	1.12 GJ / HDD	2,630 HDD	2,949 GJ	0.98
A05-0004	Vancouver	GAS-0004	Install Date: 09/09/2005	254236	1178545	2004-08-31	2005-08-31	366	Consumption	3,595 GJ	3,614 GJ	Heating	2.94 GJ	18.00 °C	0.97 GJ / HDD	2,629 HDD	2,539 GJ	0.98
A05-0005	Vancouver	GAS-0005	Install Date: 09/09/2005	610023	1178546	2004-09-01	2005-08-31	365	Consumption	3,163 GJ	3,163 GJ	Heating	2.26 GJ	18.00 °C	0.89 GJ / HDD	2,630 HDD	2,337 GJ	0.97
A05-0006	Vancouver	GAS-0006	Install Date: 08/02/2005	704208	1179373	2004-08-01	2005-07-31	365	Consumption	11,077 GJ	11,129 GJ	Heating	11.82 GJ	18.00 °C	2.59 GJ / HDD	2,630 HDD	6,816 GJ	0.97
A05-0007	Fort Nelson	GAS-0007	Install Date: 10/01/2006	51073	168567	2005-10-04	2006-09-26	358	Consumption	4,986 GJ	5,041 GJ	Heating	2.09 GJ	15.50 °C	0.79 GJ / HDD	5,420 HDD	4,295 GJ	0.99
A05-0008	Vancouver	GAS-0008	Install Date: 11/01/2005	280132	1850990	2004-10-29	2005-10-27	364	Consumption	5,407 GJ	5,397 GJ	Heating	7.26 GJ	16.50 °C	1.28 GJ / HDD	2,152 HDD	2,755 GJ	0.97
A05-0009	Williams Lake	GAS-0009	Install Date: 12/12/2005	36937	367968	2004-11-30	2005-11-25	361	Consumption	1,277 GJ	1,235 GJ	Heating	-0.08 GJ	15.00 °C	0.34 GJ / HDD	3,676 HDD	1,265 GJ	0.90
A05-0010	Vancouver	GAS-0010	Install Date: 09/01/2005	266683	1178913	2004-08-21	2005-08-31	376	Consumption	40,412 GJ	40,509 GJ	Heating	42.44 GJ	17.50 °C	9.92 GJ / HDD	2,476 HDD	24,557 GJ	0.98
A05-0011	Vancouver	GAS-0011	Install Date: 04/02/2007	468596	1179742	2006-03-01	2007-03-15	380	Consumption	6,310 GJ	6,292 GJ	Heating	6.72 GJ	14.00 °C	2.12 GJ / HDD	1,760 HDD	3,739 GJ	0.99
A05-0012	Vancouver	GAS-0012	Install Date: 09/20/2005	387051	500068	2004-09-15	2005-09-13	364	Consumption	1,249 GJ	1,247 GJ	Heating	0.13 GJ	17.50 °C	0.49 GJ / HDD	2,466 HDD	1,201 GJ	0.98
A05-0015	Vancouver	GAS-0015	Install Date: 09/01/2008	472188	686646	2007-08-18	2008-08-19	368	Consumption	884 GJ	883 GJ	Heating	1.14 GJ	16.00 °C	0.19 GJ / HDD	2,420 HDD	465 GJ	0.98
A05-0017	Vancouver	GAS-0017	Install Date: 09/01/2005	684089	772342	2004-09-01	2005-08-31	365	Consumption	1,513 GJ	1,516 GJ	Heating	0.10 GJ	16.00 °C	0.73 GJ / HDD	2,027 HDD	1,480 GJ	0.95
A05-0019	Vancouver	GAS-0019	Install Date: 10/05/2005	256597	623020	2004-09-28	2005-09-26	364	Consumption	2,838 GJ	2,782 GJ	Heating	1.60 GJ	16.50 °C	1.02 GJ / HDD	2,158 HDD	2,200 GJ	0.95
A05-0020	Vancouver	GAS-0020	Install Date: 10/05/2005	413028	1016484	2004-09-16	2005-09-13	363	Consumption	2,395 GJ	2,394 GJ	Heating	0.78 GJ	17.50 °C	0.86 GJ / HDD	2,461 HDD	2,109 GJ	0.96
A05-0021	Vancouver	GAS-0021	Install Date: 10/24/2005	399773	498623	2004-10-15	2005-10-13	364	Consumption	1,381 GJ	1,380 GJ	Heating	1.18 GJ	16.00 °C	0.47 GJ / HDD	2,035 HDD	949 GJ	0.98
A05-0022	Vancouver	GAS-0022	Install Date: 01/05/2006	311848	1696560	2005-01-01	2005-12-31	365	Consumption	2,655 GJ	2,690 GJ	Heating	2.42 GJ	17.00 °C	0.76 GJ / HDD	2,367 HDD	1,807 GJ	0.98
A05-0023	Quesnel	GAS-0023	Install Date: 11/01/2005	35729	372654	2004-09-25	2005-09-23	364	Consumption	432 GJ	429 GJ	Heating	0.13 GJ	15.00 °C	0.11 GJ / HDD	3,476 HDD	382 GJ	0.96
A05-0024	Mission	GAS-0024	Install Date: 11/03/2006	705498	1234106	2005-11-01	2006-10-31	365	Consumption	29,708 GJ	29,708 GJ	Non-Weather						
A05-0026	Vancouver	GAS-0026	Install Date: 12/07/2006	423077	639998	2005-11-17	2006-11-16	365	Consumption	840 GJ	830 GJ	Heating	0.66 GJ	17.50 °C	0.23 GJ / HDD	2,528 HDD	589 GJ	0.86
A05-0027	Vancouver	GAS-0027	Install Date: 11/22/2005	525328	646949	2004-11-06	2005-11-04	364	Consumption	2,154 GJ	2,146 GJ	Heating	1.37 GJ	16.50 °C	0.77 GJ / HDD	2,141 HDD	1,648 GJ	0.95
A05-0028	Mission	GAS-0028	Install Date: 06/29/2006	545094	565844	2005-06-29	2006-06-27	364	Consumption	3,677 GJ	3,677 GJ	Non-Weather						
A05-0029	Vancouver	GAS-0029	Install Date: 10/26/2006	617167	1025771	2005-10-14	2006-10-13	365	Consumption	1,809 GJ	1,806 GJ	Heating	1.48 GJ	13.00 °C	0.96 GJ / HDD	1,322 HDD	1,267 GJ	0.98
A05-0030	Vancouver	GAS-0030	Install Date: 10/01/2006	290739	522035	2005-06-23	2006-06-22	365	Consumption	1,099 GJ	1,160 GJ	Heating	1.19 GJ	12.50 °C	0.60 GJ / HDD	1,206 HDD	725 GJ	0.97
A05-0031	Vancouver	GAS-0031	Install Date: 12/23/2005	318638	481313	2004-12-10	2005-12-07	363	Consumption	1,665 GJ	1,664 GJ	Heating	2.51 GJ	18.00 °C	0.28 GJ / HDD	2,645 HDD	752 GJ	0.98
A05-0032	Vancouver	GAS-0032	Install Date: 09/30/2006	612048	1179455	2005-10-01	2006-09-30	365	Consumption	15,238 GJ	15,234 GJ	Heating	22.13 GJ	15.50 °C	3.70 GJ / HDD	1,935 HDD	7,156 GJ	0.96
A05-0033	Vancouver	GAS-0033	Install Date: 02/22/2006	310861	1696560	2005-02-01	2006-01-31	365	Consumption	4,370 GJ	4,372 GJ	Heating	6.26 GJ	18.00 °C	0.80 GJ / HDD	2,597 HDD	2,087 GJ	0.95
A05-0034	Vancouver	GAS-0034	Install Date: 10/05/2006	522033	847135	2005-10-06	2006-10-05	365	Consumption	110 GJ	111 GJ	Heating	0.14 GJ	13.50 °C	0.04 GJ / HDD	1,433 HDD	58 GJ	0.99
A05-0035	Fernie	GAS-0035	Install Date: 01/04/2007	236764	151124	2005-12-07	2006-12-05	364	Consumption	1,699 GJ	1,691 GJ	Heating	1.56 GJ	17.00 °C	0.29 GJ / HDD	3,931 HDD	1,123 GJ	0.94
A05-0037	Vancouver	GAS-0037	Install Date: 08/23/2006	313476	1307154	2005-08-24	2006-07-24	335	Consumption	1,899 GJ	1,858 GJ	Heating	2.99 GJ	14.50 °C	0.51 GJ / HDD	1,684 HDD	855 GJ	0.90
A05-0040	Vancouver	GAS-0040	Install Date: 03/16/2006	811250	1639618	2005-03-01	2006-02-28	365	Consumption	17,993 GJ	17,987 GJ	Heating	31.78 GJ	17.00 °C	2.80 GJ / HDD	2,284 HDD	6,385 GJ	0.96
A05-0041	Vancouver	GAS-0041	Install Date: 04/06/2006	308349	623991	2005-03-31	2006-03-29	364	Consumption	1,223 GJ	1,221 GJ	Heating	0.98 GJ	18.00 °C	0.33 GJ / HDD	2,640 HDD	865 GJ	0.88
A05-0042	Vancouver	GAS-0042	Install Date: 04/06/2006	308141	623990	2005-03-31	2006-03-29	364	Consumption	1,301 GJ	1,313 GJ	Heating	1.32 GJ	18.00 °C	0.32 GJ / HDD	2,640 HDD	835 GJ	0.92
A05-0043	Vancouver	GAS-0043	Install Date: 05/01/2007	670431	1696560	2006-05-01	2007-04-30	365	Consumption	7,890 GJ	7,891 GJ	Heating	8.24 GJ	17.50 °C	1.87 GJ / HDD	2,608 HDD	4,884 GJ	0.95
A05-0044	Vancouver	GAS-0044	Install Date: 09/05/2006	388193	622935	2005-08-13	2006-08-14	367	Consumption	1,312 GJ	1,308 GJ	Heating	0.09 GJ	13.50 °C	0.88 GJ / HDD	1,439 HDD	1,273 GJ	0.99
A05-0045	Vancouver	GAS-0045	Install Date: 08/11/2006	317893	1178526	2005-08-01	2006-07-31	365	Consumption	8,784 GJ	8,780 GJ	Heating	7.24 GJ	17.50 °C	2.43 GJ / HDD	2,525 HDD	6,138 GJ	0.97

Base Period Summary

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter				Base Period			Category			Analysis						
Name	Weather Station	Name	Description	Premise ID	Account Number	Start	End	Days	Category	Actual	Baseline	Type	Base Load	B.P.T	Weather Factor	Degree Days	Weather Component	R2
A05-0046	Vancouver	GAS-0046	Install Date: 02/05/2007	311883	1179092	2006-02-01	2007-01-31	365	Consumption	7,436 GJ	7,436 GJ	Heating	8.02 GJ	16.00 °C	2.04 GJ / HDD	2,208 HDD	4,510 GJ	0.99
A05-0048	Vancouver	GAS-0048	Install Date: 09/25/2006	403864	622935	2005-09-15	2006-09-14	365	Consumption	1,643 GJ	1,669 GJ	Heating	0.00 GJ	13.50 °C	1.16 GJ / HDD	1,441 HDD	1,669 GJ	0.99
A05-0050	Vancouver	GAS-0050	Install Date: 06/12/2007	360590	498499	2006-05-11	2007-05-09	364	Consumption	1,922 GJ	1,922 GJ	Heating	2.69 GJ	13.50 °C	0.62 GJ / HDD	1,523 HDD	943 GJ	0.96
A05-0051	Vancouver	GAS-0051	Install Date: 10/06/2006	409296	1247800	2005-09-14	2006-09-13	365	Consumption	5,223 GJ	5,316 GJ	Heating	2.92 GJ	17.50 °C	1.68 GJ / HDD	2,527 HDD	4,250 GJ	0.98
A05-0052	Vancouver	GAS-0052	Install Date: 08/01/2006	304098	1317022	2005-07-29	2006-07-28	365	Consumption	3,949 GJ	3,908 GJ	Heating	2.81 GJ	17.50 °C	1.14 GJ / HDD	2,522 HDD	2,883 GJ	0.95
A05-0053	Vancouver	GAS-0053	Install Date: 08/31/2006	282017	623537	2005-08-27	2006-08-29	368	Consumption	4,128 GJ	4,129 GJ	Heating	2.01 GJ	20.00 °C	1.00 GJ / HDD	3,394 HDD	3,388 GJ	0.97
A05-0054	Vancouver	GAS-0054	Install Date: 06/20/2006	332426	803143	2004-06-01	2006-06-15	745	Consumption	11,392 GJ	11,503 GJ	Heating	6.52 GJ	16.50 °C	1.51 GJ / HDD	4,412 HDD	6,644 GJ	1.00
A05-0055	Vancouver	GAS-0055	Install Date: 06/20/2006	332435	803143	2005-06-16	2006-06-15	365	Consumption	5,792 GJ	5,831 GJ	Heating	7.03 GJ	16.00 °C	1.57 GJ / HDD	2,081 HDD	3,264 GJ	0.97
A05-0056	Vancouver	GAS-0056	Install Date: 06/20/2006	332417	803143	2005-06-16	2006-06-15	365	Consumption	1,471 GJ	1,472 GJ	Heating	1.79 GJ	16.50 °C	0.37 GJ / HDD	2,223 HDD	819 GJ	0.98
A05-0057	Vancouver	GAS-0057	Install Date: 06/20/2006	332425	803143	2005-06-16	2006-06-15	365	Consumption	1,419 GJ	1,425 GJ	Heating	1.72 GJ	15.50 °C	0.41 GJ / HDD	1,944 HDD	797 GJ	0.97
A05-0058	Vancouver	GAS-0058	Install Date: 06/20/2006	332349	803143	2005-06-16	2006-06-15	365	Consumption	2,696 GJ	2,406 GJ	Heating	4.10 GJ	13.00 °C	0.69 GJ / HDD	1,321 HDD	911 GJ	0.99
A05-0059	Vancouver	GAS-0059	Install Date: 06/20/2006	332382	803143	2005-06-16	2006-06-15	365	Consumption	2,669 GJ	2,679 GJ	Heating	1.73 GJ	18.00 °C	0.76 GJ / HDD	2,682 HDD	2,047 GJ	0.98
A05-0060	Vancouver	GAS-0060	Install Date: 06/20/2006	332383	803143	2005-06-16	2006-06-15	365	Consumption	2,377 GJ	2,374 GJ	Heating	2.18 GJ	17.00 °C	0.67 GJ / HDD	2,372 HDD	1,580 GJ	0.98
A05-0061	Vancouver	GAS-0061	Install Date: 06/20/2006	332384	803143	2005-06-16	2006-06-15	365	Consumption	2,862 GJ	2,887 GJ	Heating	2.83 GJ	18.00 °C	0.69 GJ / HDD	2,682 HDD	1,854 GJ	0.98
A05-0062	Vancouver	GAS-0062	Install Date: 10/14/2006	522363	1196428	2005-10-01	2006-09-30	365	Consumption	9,071 GJ	9,060 GJ	Heating	0.64 GJ	15.50 °C	4.56 GJ / HDD	1,935 HDD	8,827 GJ	0.98
A05-0065	Vancouver	GAS-0065	Install Date: 12/18/2006	275850	509483	2005-10-28	2006-10-30	368	Consumption	4,788 GJ	4,804 GJ	Heating	0.58 GJ	15.50 °C	2.32 GJ / HDD	1,979 HDD	4,590 GJ	0.98
A05-0066	Cranbrook	GAS-0066	Install Date: 11/24/2006	30724	1178446	2005-11-04	2006-11-03	365	Consumption	3,232 GJ	3,239 GJ	Heating	2.38 GJ	16.00 °C	0.64 GJ / HDD	3,682 HDD	2,370 GJ	0.95
A05-0068	Vancouver	GAS-0068	Install Date: 09/01/2006	307235	1298386	2005-08-30	2006-08-31	367	Consumption	4,612 GJ	4,339 GJ	Heating	6.78 GJ	16.00 °C	0.89 GJ / HDD	2,081 HDD	1,852 GJ	0.71
A05-0069	Vancouver	GAS-0069	Install Date: 09/05/2006	414759	1178545	2005-09-01	2006-08-31	365	Consumption	8,905 GJ	8,869 GJ	Heating	7.48 GJ	18.00 °C	2.27 GJ / HDD	2,699 HDD	6,139 GJ	0.98
A05-0070	Vancouver	GAS-0070	Install Date: 09/05/2006	608173	1178545	2005-09-01	2006-08-31	365	Consumption	7,285 GJ	7,274 GJ	Heating	3.71 GJ	18.00 °C	2.19 GJ / HDD	2,699 HDD	5,921 GJ	0.99
A05-0072	Vancouver	GAS-0072	Install Date: 10/27/2006	248451	497887	2005-10-01	2006-09-30	365	Consumption	2,988 GJ	2,993 GJ	Heating	1.80 GJ	17.00 °C	0.99 GJ / HDD	2,364 HDD	2,338 GJ	0.99
A05-0077	Kamloops	GAS-0077	Install Date: 11/22/2006	64492	358232	2005-11-15	2006-11-14	365	Consumption	1,222 GJ	1,224 GJ	Heating	0.15 GJ	14.00 °C	0.52 GJ / HDD	2,236 HDD	1,168 GJ	0.99
A05-0079	Vancouver	GAS-0079	Install Date: 07/07/2006	606229	772955	2005-07-05	2006-06-30	361	Consumption	5,315 GJ	5,333 GJ	Heating	10.33 GJ	14.50 °C	0.95 GJ / HDD	1,685 HDD	1,606 GJ	0.97
A05-0080	Vancouver	GAS-0080	Install Date: 08/31/2006	256346	1121989	2005-08-26	2006-08-31	371	Consumption	2,986 GJ	3,060 GJ	Heating	2.81 GJ	16.50 °C	0.91 GJ / HDD	2,226 HDD	2,017 GJ	0.85
A05-0081	Vancouver	GAS-0081	Install Date: 09/13/2006	286361	1696560	2005-09-01	2006-08-31	365	Consumption	34,051 GJ	34,039 GJ	Heating	36.53 GJ	18.00 °C	7.67 GJ / HDD	2,699 HDD	20,708 GJ	0.98
A05-0082	Vancouver	GAS-0082	Install Date: 10/26/2006	285146	1696560	2005-10-01	2006-09-30	365	Consumption	8,599 GJ	8,589 GJ	Heating	11.33 GJ	17.00 °C	1.88 GJ / HDD	2,364 HDD	4,453 GJ	0.96
A05-0084	Vancouver	GAS-0084	Install Date: 10/18/2006	645039	772342	2005-09-16	2006-09-15	365	Consumption	730 GJ	747 GJ	Heating	0.05 GJ	15.00 °C	0.40 GJ / HDD	1,817 HDD	729 GJ	0.96
A05-0085	Vancouver	GAS-0085	Install Date: 07/05/2006	525780	647014	2005-07-08	2006-06-23	351	Consumption	2,988 GJ	2,972 GJ	Heating	1.39 GJ	18.00 °C	0.93 GJ / HDD	2,672 HDD	2,486 GJ	0.98
A05-0086	Penticton	GAS-0086	Install Date: 05/31/2007	191021	318777	2006-05-17	2007-05-17	366	Consumption	7,289 GJ	7,323 GJ	Heating	3.73 GJ	12.00 °C	3.39 GJ / HDD	1,758 HDD	5,956 GJ	1.00
A05-0087	Mission	GAS-0087	Install Date: 01/16/2007	779272	1179883	2006-01-01	2006-12-31	365	Consumption	5,748 GJ	5,755 GJ	Heating	7.08 GJ	16.00 °C	1.37 GJ / HDD	2,316 HDD	3,170 GJ	0.81
A05-0089	Williams Lake	GAS-0089	Install Date: 11/26/2006	45157	1701887	2005-11-19	2006-11-20	367	Consumption	1,554 GJ	1,582 GJ	Heating	0.00 GJ	11.50 °C	0.58 GJ / HDD	2,744 HDD	1,581 GJ	0.97
A05-0093	Vancouver	GAS-0093	Install Date: 11/01/2006	285521	623591	2005-10-28	2006-10-27	365	Consumption	4,199 GJ	4,140 GJ	Heating	4.03 GJ	17.50 °C	1.05 GJ / HDD	2,539 HDD	2,668 GJ	0.87
A05-0094	Vancouver	GAS-0094	Install Date: 09/01/2006	508110	1196426	2005-09-01	2006-08-31	365	Consumption	1,913 GJ	1,909 GJ	Heating	0.86 GJ	18.00 °C	0.59 GJ / HDD	2,699 HDD	1,594 GJ	0.95
A05-0095	Kelowna	GAS-0095	Install Date: 08/01/2007	160979	267929	2006-07-05	2007-07-05	366	Consumption	3,749 GJ	3,735 GJ	Heating	1.27 GJ	18.50 °C	0.84 GJ / HDD	3,878 HDD	3,269 GJ	0.93
A05-0096	Fort Nelson	GAS-0096	Install Date: 08/11/2006	51072	168568	2005-08-04	2006-08-02	364	Consumption	2,413 GJ	2,417 GJ	Heating	0.08 GJ	12.00 °C	0.53 GJ / HDD	4,518 HDD	2,389 GJ	0.99

Base Period Summary

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter				Base Period			Category			Analysis						
Name	Weather Station	Name	Description	Premise ID	Account Number	Start	End	Days	Category	Actual	Baseline	Type	Base Load	B.P.T	Weather Factor	Degree Days	Weather Component	R2
A05-0098	Mission	GAS-0098	Install Date: 12/16/2006	782766	1179918	2005-12-01	2006-11-30	365	Consumption	7,189 GJ	7,189 GJ	Heating	4.31 GJ	16.00 °C	2.43 GJ / HDD	2,310 HDD	5,614 GJ	0.92
A05-0099	Vancouver	GAS-0099	Install Date: 10/12/2006	652994	1179439	2005-10-01	2006-09-30	365	Consumption	8,128 GJ	8,122 GJ	Heating	4.16 GJ	17.50 °C	2.62 GJ / HDD	2,520 HDD	6,602 GJ	0.98
A05-0100	Mission	GAS-0100	Install Date: 12/07/2006	771423	950726	2005-12-09	2006-12-06	363	Consumption	1,612 GJ	1,656 GJ	Heating	1.78 GJ	16.50 °C	0.42 GJ / HDD	2,406 HDD	1,009 GJ	0.84
A05-0101	Vancouver	GAS-0101	Install Date: 12/07/2006	266117	1891403	2005-11-29	2006-11-27	364	Consumption	2,627 GJ	2,663 GJ	Heating	0.31 GJ	13.50 °C	1.77 GJ / HDD	1,439 HDD	2,550 GJ	0.98
A05-0102	Vancouver	GAS-0102	Install Date: 06/01/2007	702112	1179472	2006-06-01	2007-05-31	365	Consumption	38,602 GJ	38,607 GJ	Heating	40.54 GJ	15.50 °C	11.70 GJ / HDD	2,035 HDD	23,816 GJ	0.97
A05-0103	Vancouver	GAS-0103	Install Date: 05/24/2007	449169	647243	2006-05-04	2007-05-03	365	Consumption	1,909 GJ	1,910 GJ	Heating	2.81 GJ	17.00 °C	0.36 GJ / HDD	2,452 HDD	886 GJ	0.90
A05-0104	Vancouver	GAS-0104	Install Date: 04/19/2007	483716	1696560	2006-04-01	2007-03-31	365	Consumption	2,350 GJ	2,351 GJ	Heating	3.07 GJ	17.50 °C	0.47 GJ / HDD	2,597 HDD	1,229 GJ	0.90
A05-0105	Vancouver	GAS-0105	Install Date: 04/27/2007	266076	647243	2006-03-03	2007-03-01	364	Consumption	2,494 GJ	2,483 GJ	Heating	3.69 GJ	20.00 °C	0.33 GJ / HDD	3,464 HDD	1,141 GJ	0.92
A05-0106	Vancouver	GAS-0106	Install Date: 04/27/2007	265806	1696560	2006-04-01	2007-03-31	365	Consumption	3,067 GJ	3,068 GJ	Heating	5.16 GJ	17.50 °C	0.46 GJ / HDD	2,597 HDD	1,184 GJ	0.97
A05-0109	Vancouver	GAS-0109	Install Date: 11/03/2006	313159	656898	2005-10-08	2006-10-10	368	Consumption	2,637 GJ	2,606 GJ	Heating	3.00 GJ	17.00 °C	0.63 GJ / HDD	2,382 HDD	1,503 GJ	0.97
A05-0110	Vancouver	GAS-0110	Install Date: 10/12/2006	721346	1300786	2005-10-01	2006-09-30	365	Consumption	3,307 GJ	3,303 GJ	Heating	1.43 GJ	16.00 °C	1.34 GJ / HDD	2,071 HDD	2,781 GJ	0.98
A05-0112	Vancouver	GAS-0112	Install Date: 10/18/2006	505743	1178736	2005-10-01	2006-09-30	365	Consumption	5,481 GJ	5,476 GJ	Heating	3.29 GJ	17.50 °C	1.70 GJ / HDD	2,520 HDD	4,276 GJ	0.99
A05-0114	Vancouver	GAS-0114	Install Date: 01/29/2007	290590	1696560	2006-01-01	2006-12-31	365	Consumption	10,839 GJ	10,847 GJ	Heating	15.88 GJ	16.00 °C	2.40 GJ / HDD	2,102 HDD	5,051 GJ	0.97
A05-0115	Vancouver	GAS-0115	Install Date: 04/18/2007	257082	1696560	2006-04-01	2007-03-31	365	Consumption	6,129 GJ	6,132 GJ	Heating	10.43 GJ	17.50 °C	0.89 GJ / HDD	2,597 HDD	2,323 GJ	0.84
A05-0116	Abbotsford	GAS-0116	Install Date: 04/18/2007	737983	1240604	2006-04-08	2007-04-10	368	Consumption	2,594 GJ	2,585 GJ	Heating	2.22 GJ	17.00 °C	0.70 GJ / HDD	2,544 HDD	1,769 GJ	0.91
A05-0119	Vancouver	GAS-0119	Install Date: 06/28/2007	279229	1178600	2006-06-01	2007-05-31	365	Consumption	10,143 GJ	10,145 GJ	Heating	10.82 GJ	17.00 °C	2.52 GJ / HDD	2,463 HDD	6,198 GJ	0.99
A05-0120	Vancouver	GAS-0120	Install Date: 04/25/2007	480833	1037859	2006-04-11	2007-04-10	365	Consumption	5,782 GJ	5,495 GJ	Heating	5.69 GJ	17.00 °C	1.40 GJ / HDD	2,449 HDD	3,420 GJ	0.94
A05-0122	Vancouver	GAS-0122	Install Date: 12/01/2006	330288	711233	2005-12-01	2006-11-30	365	Consumption	4,901 GJ	4,913 GJ	Heating	7.88 GJ	17.00 °C	0.85 GJ / HDD	2,396 HDD	2,038 GJ	0.84
A05-0123	Vancouver	GAS-0123	Install Date: 10/01/2007	473191	734697	2006-08-09	2007-09-10	398	Consumption	2,528 GJ	2,570 GJ	Heating	2.49 GJ	16.00 °C	0.71 GJ / HDD	2,210 HDD	1,579 GJ	0.78
A05-0125	Vancouver	GAS-0125	Install Date: 08/05/2008	309195	623999	2007-06-29	2008-06-30	368	Consumption	2,677 GJ	2,676 GJ	Heating	2.38 GJ	16.50 °C	0.70 GJ / HDD	2,564 HDD	1,801 GJ	1.00
A05-0131	Vancouver	GAS-0131	Install Date: 05/01/2007	257372	1178474	2006-05-01	2007-04-30	365	Consumption	24,715 GJ	24,715 GJ	Heating	47.95 GJ	17.50 °C	2.77 GJ / HDD	2,608 HDD	7,213 GJ	0.89
A05-0132	Vancouver	GAS-0132	Install Date: 10/01/2008	688856	798495	2007-09-22	2008-09-19	364	Consumption	1,873 GJ	1,838 GJ	Heating	-0.01 GJ	16.50 °C	0.72 GJ / HDD	2,569 HDD	1,842 GJ	0.98
A05-0133	Vancouver	GAS-0133	Install Date: 09/01/2007	785675	1179701	2006-09-01	2007-08-31	365	Consumption	4,935 GJ	4,935 GJ	Heating	2.14 GJ	17.50 °C	1.57 GJ / HDD	2,650 HDD	4,154 GJ	0.98
A05-0134	Vancouver	GAS-0134	Install Date: 09/24/2007	541514	1178602	2006-09-01	2007-08-31	365	Consumption	5,064 GJ	5,065 GJ	Heating	2.63 GJ	18.00 °C	1.46 GJ / HDD	2,811 HDD	4,106 GJ	0.99
A05-0136	Vancouver	GAS-0136	Install Date: 10/01/2007	299702	1323619	2006-10-01	2007-09-30	365	Consumption	4,540 GJ	4,536 GJ	Heating	4.22 GJ	16.00 °C	1.34 GJ / HDD	2,231 HDD	2,995 GJ	0.95
A05-0137	Vancouver	GAS-0137	Install Date: 09/01/2007	478417	1323616	2006-09-01	2007-08-31	365	Consumption	5,503 GJ	5,504 GJ	Heating	5.81 GJ	15.50 °C	1.64 GJ / HDD	2,066 HDD	3,382 GJ	1.00
A05-0138	Vancouver	GAS-0138	Install Date: 09/01/2007	420870	1323620	2006-09-01	2007-08-31	365	Consumption	2,859 GJ	2,860 GJ	Heating	2.64 GJ	18.00 °C	0.68 GJ / HDD	2,811 HDD	1,897 GJ	0.98
A05-0140	Vancouver	GAS-0140	Install Date: 11/21/2007	365653	665969	2006-11-01	2007-10-31	365	Consumption	7,087 GJ	7,098 GJ	Heating	7.42 GJ	17.50 °C	1.63 GJ / HDD	2,697 HDD	4,391 GJ	0.93
A05-0144	Vancouver	GAS-0144	Install Date: 07/25/2007	496208	498924	2006-07-01	2007-07-03	368	Consumption	3,917 GJ	3,917 GJ	Non-Weather						
A05-0150	Vancouver	GAS-0150	Install Date: 08/01/2007	295067	623719	2006-06-29	2007-06-27	364	Consumption	3,860 GJ	3,860 GJ	Heating	3.49 GJ	17.00 °C	1.04 GJ / HDD	2,501 HDD	2,590 GJ	0.97
A05-0154	Vancouver	GAS-0154	Install Date: 04/07/2008	515881	1580407	2006-03-09	2007-03-07	364	Consumption	3,787 GJ	3,666 GJ	Heating	2.72 GJ	17.50 °C	1.03 GJ / HDD	2,610 HDD	2,676 GJ	0.88
A05-0155	Vancouver	GAS-0155	Install Date: 07/17/2007	536113	1178582	2006-07-01	2007-06-30	365	Consumption	6,219 GJ	6,217 GJ	Heating	7.28 GJ	14.50 °C	1.98 GJ / HDD	1,796 HDD	3,559 GJ	0.99
A05-0156	Vancouver	GAS-0156	Install Date: 04/05/2008	302558	1178576	2007-04-01	2008-03-31	366	Consumption	17,790 GJ	17,796 GJ	Heating	14.39 GJ	15.00 °C	6.05 GJ / HDD	2,072 HDD	12,528 GJ	0.99
A05-0159	Vancouver	GAS-0159	Install Date: 08/30/2007	423566	640106	2006-08-16	2007-08-15	365	Consumption	1,428 GJ	1,429 GJ	Heating	0.38 GJ	17.50 °C	0.49 GJ / HDD	2,653 HDD	1,291 GJ	0.97
A05-0163	Vancouver	GAS-0163	Install Date: 11/02/2007	605934	772334	2006-06-03	2007-06-01	364	Consumption	5,105 GJ	5,149 GJ	Heating	3.16 GJ	11.50 °C	3.72 GJ / HDD	1,076 HDD	4,001 GJ	0.71

Base Period Summary

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter				Base Period			Category			Analysis						
Name	Weather Station	Name	Description	Premise ID	Account Number	Start	End	Days	Category	Actual	Baseline	Type	Base Load	B.P.T	Weather Factor	Degree Days	Weather Component	R2
A05-0169	Mission	GAS-0169	Install Date: 04/03/2008	272939	1868083	2007-03-14	2008-03-11	364	Consumption	3,279 GJ	3,279 GJ	Non-Weather						
A05-0171	Warfield	GAS-0171	Install Date: 10/01/2008	197335	298535	2006-08-18	2007-08-17	365	Consumption	4,402 GJ	4,415 GJ	Heating	3.68 GJ	16.00 °C	0.97 GJ / HDD	3,158 HDD	3,071 GJ	0.92
A05-0173	Prince George	GAS-0173	Install Date: 09/01/2008	14291	127587	2007-08-22	2008-08-22	367	Consumption	1,556 GJ	1,548 GJ	Heating	0.04 GJ	13.50 °C	0.41 GJ / HDD	3,750 HDD	1,534 GJ	0.99
A05-0174	Prince George	GAS-0174	Install Date: 09/02/2008	10891	127587	2007-08-10	2008-08-13	370	Consumption	1,988 GJ	1,951 GJ	Heating	0.10 GJ	14.50 °C	0.47 GJ / HDD	4,077 HDD	1,913 GJ	0.99
A05-0176	Vancouver	GAS-0176	Install Date: 05/01/2009	510439	742126	2008-05-02	2009-04-30	364	Consumption	7,598 GJ	7,609 GJ	Heating	5.50 GJ	17.50 °C	1.94 GJ / HDD	2,885 HDD	5,609 GJ	0.97
A05-0177	Vancouver	GAS-0177	Install Date: 07/01/2009	307218	498155	2008-06-28	2009-06-26	364	Consumption	3,287 GJ	3,285 GJ	Heating	4.15 GJ	17.00 °C	0.67 GJ / HDD	2,652 HDD	1,776 GJ	0.97
A05-0178	Kelowna	GAS-0178	Install Date: 09/01/2009	161485	268955	2008-08-27	2009-08-25	364	Consumption	3,026 GJ	3,023 GJ	Heating	0.33 GJ	15.00 °C	0.90 GJ / HDD	3,238 HDD	2,904 GJ	0.99
A05-0180	Vancouver	GAS-0180	Install Date: 05/22/2009	304568	498108	2008-04-29	2009-04-28	365	Consumption	4,186 GJ	4,400 GJ	Heating	2.34 GJ	15.50 °C	1.55 GJ / HDD	2,288 HDD	3,548 GJ	0.70
A05-0181	Vancouver	GAS-0181	Install Date: 09/01/2009	490831	1126956	2008-09-03	2009-08-31	363	Consumption	3,455 GJ	3,447 GJ	Heating	0.25 GJ	18.50 °C	1.08 GJ / HDD	3,120 HDD	3,358 GJ	0.78
A05-0183	Vancouver	GAS-0183	Install Date: 06/01/2009	482862	736951	2008-05-10	2009-05-08	364	Consumption	830 GJ	832 GJ	Heating	0.04 GJ	14.50 °C	0.41 GJ / HDD	1,992 HDD	816 GJ	0.97
A05-0184	Vancouver	GAS-0184	Install Date: 11/04/2009	325339	692350	2008-09-20	2009-10-20	396	Consumption	1,083 GJ	1,071 GJ	Heating	0.07 GJ	13.50 °C	0.60 GJ / HDD	1,734 HDD	1,045 GJ	0.92
A05-0185	Vancouver	GAS-0185	Install Date: 11/02/2009	399907	1178545	2008-11-01	2009-10-31	365	Consumption	10,526 GJ	10,672 GJ	Heating	10.03 GJ	17.50 °C	2.53 GJ / HDD	2,771 HDD	7,010 GJ	0.96
A05-0188	Powell River	GAS-0188	Install Date: 09/01/2009	948964	1650898	2008-08-29	2009-08-27	364	Consumption	15,078 GJ	15,075 GJ	Heating	15.68 GJ	17.00 °C	3.17 GJ / HDD	2,956 HDD	9,365 GJ	0.96
A05-0189	Vancouver	GAS-0189	Install Date: 07/02/2009	562819	858120	2008-05-28	2009-05-26	364	Consumption	3,007 GJ	3,078 GJ	Heating	4.08 GJ	15.00 °C	0.74 GJ / HDD	2,142 HDD	1,591 GJ	0.98
A05-0190	Vancouver	GAS-0190	Install Date: 10/01/2009	462258	564349	2008-10-01	2009-09-30	365	Consumption	2,324 GJ	2,324 GJ	Heating	2.15 GJ	17.00 °C	0.59 GJ / HDD	2,622 HDD	1,538 GJ	0.98
A05-0192	Vancouver	GAS-0192	Install Date: 11/17/2009	267973	1862457	2008-10-31	2009-10-28	363	Consumption	1,902 GJ	1,915 GJ	Heating	1.35 GJ	17.50 °C	0.52 GJ / HDD	2,754 HDD	1,425 GJ	0.98
A05-0193	Vancouver	GAS-0193	Install Date: 06/29/2009	309516	655948	2008-05-07	2009-05-05	364	Consumption	2,592 GJ	2,648 GJ	Heating	2.86 GJ	16.00 °C	0.67 GJ / HDD	2,412 HDD	1,606 GJ	0.89
A05-0195	Vancouver	GAS-0195	Install Date: 09/23/2009	726355	1180024	2008-09-01	2009-08-31	365	Consumption	5,917 GJ	5,915 GJ	Heating	0.44 GJ	15.00 °C	2.76 GJ / HDD	2,087 HDD	5,754 GJ	0.98
A05-0196	Vancouver	GAS-0196	Install Date: 06/09/2009	325654	692347	2008-04-19	2009-04-20	367	Consumption	2,879 GJ	2,884 GJ	Heating	3.25 GJ	16.50 °C	0.65 GJ / HDD	2,619 HDD	1,691 GJ	0.77
A05-0197	Vancouver	GAS-0197	Install Date: 06/09/2009	326188	692347	2008-05-21	2009-05-19	364	Consumption	3,387 GJ	3,382 GJ	Heating	5.54 GJ	14.00 °C	0.73 GJ / HDD	1,869 HDD	1,365 GJ	0.96
A05-0206	Vancouver	GAS-0206	Install Date: 06/01/2009	345442	661463	2008-05-10	2009-05-07	363	Consumption	3,671 GJ	3,677 GJ	Heating	4.91 GJ	17.00 °C	0.70 GJ / HDD	2,711 HDD	1,895 GJ	0.62
A05-0210	Vancouver	GAS-0210	Install Date: 11/06/2009	541687	1178607	2008-11-01	2009-10-31	365	Consumption	9,470 GJ	9,525 GJ	Heating	11.12 GJ	14.00 °C	2.99 GJ / HDD	1,828 HDD	5,467 GJ	0.96
A05-0212	Vancouver	GAS-0212	Install Date: 12/03/2009	675822	1139860	2008-11-05	2009-11-03	364	Consumption	4,992 GJ	5,021 GJ	Heating	4.32 GJ	18.00 °C	1.18 GJ / HDD	2,929 HDD	3,446 GJ	0.99
A05-0213	Vancouver	GAS-0213	Install Date: 12/03/2009	675784	1139861	2008-12-05	2009-12-03	364	Consumption	5,318 GJ	5,318 GJ	Non-Weather						
A05-0214	Vancouver	GAS-0214	Install Date: 11/30/2009	676296	795104	2008-10-01	2009-10-28	393	Consumption	2,429 GJ	2,391 GJ	Heating	2.38 GJ	17.00 °C	0.52 GJ / HDD	2,811 HDD	1,455 GJ	0.99
A05-0217	Vancouver	GAS-0217	Install Date: 08/12/2009	67113	323616	2008-06-19	2009-06-17	364	Consumption	94 GJ	94 GJ	Heating	0.04 GJ	17.50 °C	0.03 GJ / HDD	2,811 HDD	79 GJ	0.99
A05-0219	Vancouver	GAS-0219	Install Date: 12/04/2009	288862	1777251	2007-10-31	2008-10-28	364	Consumption	1,728 GJ	1,626 GJ	Heating	0.04 GJ	11.00 °C	1.42 GJ / HDD	1,134 HDD	1,610 GJ	0.90
A05-0228	Vancouver	GAS-0228	Install Date: 11/01/2009	285568	623592	2008-10-29	2009-10-28	365	Consumption	2,762 GJ	2,762 GJ	Heating	2.30 GJ	17.00 °C	0.74 GJ / HDD	2,615 HDD	1,922 GJ	0.96
A10-0247	Vancouver	GAS-0247	Install Date: 10/06/2009	703441	1179124	2008-10-01	2009-09-30	365	Consumption	18,891 GJ	18,891 GJ	Heating	27.48 GJ	17.00 °C	3.38 GJ / HDD	2,622 HDD	8,859 GJ	0.99
A10-0251	Vancouver	GAS-0251	Install Date: 11/01/2009	306259	1037617	2008-10-30	2009-10-28	364	Consumption	3,559 GJ	3,539 GJ	Heating	3.74 GJ	16.00 °C	0.94 GJ / HDD	2,328 HDD	2,178 GJ	0.99
A10-0253	Kamloops	GAS-0253	Install Date: 12/15/2009	58610	1946680	2008-11-08	2009-11-06	364	Consumption	560 GJ	552 GJ	Heating	0.74 GJ	13.00 °C	0.11 GJ / HDD	2,534 HDD	281 GJ	0.96

APPENDIX B: Base Period Analysis

(Due to large file size, this Appendix is provided as a separate file)

APPENDIX C: Last Reading Dates

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site			Meter				Last Reading				
Name	Description	Code	Name	Description	Type	Account Number	Date	Days	Consumption	Cost	Days Since
A05-0003	Premise : 406662		GAS-0003	Install Date: 09/09/2005	Natural Gas	1178691	2011-02-28	28	499	0	93
A05-0004	Premise : 254236		GAS-0004	Install Date: 09/09/2005	Natural Gas	1178545	2011-02-28	28	339	0	93
A05-0005	Premise : 610023		GAS-0005	Install Date: 09/09/2005	Natural Gas	1178546	2011-02-28	28	251	0	93
A05-0006	Premise : 704208		GAS-0006	Install Date: 08/02/2005	Natural Gas	1179373	2011-02-28	28	1,023	0	93
A05-0007	Premise : 51073		GAS-0007	Install Date: 10/01/2006	Natural Gas	168567	2011-03-04	30	651	0	89
A05-0008	Premise : 280132		GAS-0008	Install Date: 11/01/2005	Natural Gas	1850990	2011-02-28	28	570	0	93
A05-0009	Premise : 36937		GAS-0009	Install Date: 12/12/2005	Natural Gas	367968	2007-05-02	6	0	0	1491
A05-0010	Premise : 266683		GAS-0010	Install Date: 09/01/2005	Natural Gas	1178913	2011-02-28	28	5,613	0	93
A05-0011	Premise : 468596		GAS-0011	Install Date: 04/02/2007	Natural Gas	1179742	2011-02-16	63	1,749	0	105
A05-0012	Premise : 387051		GAS-0012	Install Date: 09/20/2005	Natural Gas	500068	2011-03-14	31	331	0	79
A05-0015	Premise : 472188		GAS-0015	Install Date: 09/01/2008	Natural Gas	686646	2011-03-17	58	140	0	76
A05-0017	Premise : 684089		GAS-0017	Install Date: 09/01/2005	Natural Gas	772342	2011-02-25	30	218	0	96
A05-0019	Premise : 256597		GAS-0019	Install Date: 10/05/2005	Natural Gas	623020	2011-03-29	29	199	0	64
A05-0020	Premise : 413028		GAS-0020	Install Date: 10/05/2005	Natural Gas	1016484	2011-03-14	91	1,190	0	79
A05-0021	Premise : 399773		GAS-0021	Install Date: 10/24/2005	Natural Gas	498623	2011-02-14	63	360	0	107
A05-0022	Premise : 311848		GAS-0022	Install Date: 01/05/2006	Natural Gas	1696560	2011-02-28	28	295	0	93
A05-0023	Premise : 35729		GAS-0023	Install Date: 11/01/2005	Natural Gas	372654	2011-03-25	58	89	0	68
A05-0024	Premise : 705498		GAS-0024	Install Date: 11/03/2006	Natural Gas	1234106	2011-02-28	28	5,917	0	93
A05-0026	Premise : 423077		GAS-0026	Install Date: 12/07/2006	Natural Gas	639998	2011-02-14	62	265	0	107
A05-0027	Premise : 525328		GAS-0027	Install Date: 11/22/2005	Natural Gas	646949	2011-02-04	60	489	0	117
A05-0028	Premise : 545094		GAS-0028	Install Date: 06/29/2006	Natural Gas	565844	2011-01-28	29	406	0	124
A05-0029	Premise : 617167		GAS-0029	Install Date: 10/26/2006	Natural Gas	1025771	2011-03-14	28	211	0	79
A05-0030	Premise : 290739		GAS-0030	Install Date: 10/01/2006	Natural Gas	522035	2011-03-23	29	197	0	70
A05-0031	Premise : 318638		GAS-0031	Install Date: 12/23/2005	Natural Gas	481313	2011-03-08	60	276	0	85
A05-0032	Premise : 612048		GAS-0032	Install Date: 09/30/2006	Natural Gas	1179455	2011-02-28	28	1,631	0	93
A05-0033	Premise : 310861		GAS-0033	Install Date: 02/22/2006	Natural Gas	1696560	2011-02-28	28	475	0	93
A05-0034	Premise : 522033		GAS-0034	Install Date: 10/05/2006	Natural Gas	847135	2011-02-04	59	31	0	117
A05-0035	Premise : 236764		GAS-0035	Install Date: 01/04/2007	Natural Gas	151124	2011-03-07	27	180	0	86
A05-0037	Premise : 313476		GAS-0037	Install Date: 08/23/2006	Natural Gas	1307154	2011-03-23	30	194	0	70
A05-0040	Premise : 811250		GAS-0040	Install Date: 03/16/2006	Natural Gas	1639618	2011-02-28	28	2,302	0	93
A05-0041	Premise : 308349		GAS-0041	Install Date: 04/06/2006	Natural Gas	623991	2011-03-29	29	152	0	64
A05-0042	Premise : 308141		GAS-0042	Install Date: 04/06/2006	Natural Gas	623990	2011-03-29	29	133	0	64
A05-0043	Premise : 670431		GAS-0043	Install Date: 05/01/2007	Natural Gas	1696560	2011-02-28	28	605	0	93
A05-0044	Premise : 388193		GAS-0044	Install Date: 09/05/2006	Natural Gas	622935	2011-03-14	28	270	0	79
A05-0045	Premise : 317893		GAS-0045	Install Date: 08/11/2006	Natural Gas	1178526	2011-02-28	28	971	0	93

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site			Meter				Last Reading				
Name	Description	Code	Name	Description	Type	Account Number	Date	Days	Consumption	Cost	Days Since
A05-0046	Premise : 311883		GAS-0046	Install Date: 02/05/2007	Natural Gas	1179092	2011-02-28	28	892	0	93
A05-0048	Premise : 403864		GAS-0048	Install Date: 09/25/2006	Natural Gas	622935	2011-03-15	29	280	0	78
A05-0050	Premise : 360590		GAS-0050	Install Date: 06/12/2007	Natural Gas	498499	2011-02-09	63	358	0	112
A05-0051	Premise : 409296		GAS-0051	Install Date: 10/06/2006	Natural Gas	1247800	2011-02-14	31	706	0	107
A05-0052	Premise : 304098		GAS-0052	Install Date: 08/01/2006	Natural Gas	1317022	2011-03-28	31	376	0	65
A05-0053	Premise : 282017		GAS-0053	Install Date: 08/31/2006	Natural Gas	623537	2011-03-28	31	466	0	65
A05-0054	Premise : 332426		GAS-0054	Install Date: 06/20/2006	Natural Gas	803143	2011-02-16	29	530	0	105
A05-0055	Premise : 332435		GAS-0055	Install Date: 06/20/2006	Natural Gas	803143	2011-02-16	62	674	0	105
A05-0056	Premise : 332417		GAS-0056	Install Date: 06/20/2006	Natural Gas	803143	2011-01-18	62	325	0	134
A05-0057	Premise : 332425		GAS-0057	Install Date: 06/20/2006	Natural Gas	803143	2011-01-18	62	120	0	134
A05-0058	Premise : 332349		GAS-0058	Install Date: 06/20/2006	Natural Gas	803143	2011-02-16	29	224	0	105
A05-0059	Premise : 332382		GAS-0059	Install Date: 06/20/2006	Natural Gas	803143	2011-01-18	62	611	0	134
A05-0060	Premise : 332383		GAS-0060	Install Date: 06/20/2006	Natural Gas	803143	2011-01-18	62	567	0	134
A05-0061	Premise : 332384		GAS-0061	Install Date: 06/20/2006	Natural Gas	803143	2011-02-16	29	272	0	105
A05-0062	Premise : 522363		GAS-0062	Install Date: 10/14/2006	Natural Gas	1196428	2011-02-28	28	1,404	0	93
A05-0065	Premise : 275850		GAS-0065	Install Date: 12/18/2006	Natural Gas	509483	2011-03-28	31	539	0	65
A05-0066	Premise : 30724		GAS-0066	Install Date: 11/24/2006	Natural Gas	1178446	2011-03-04	29	379	0	89
A05-0068	Premise : 307235		GAS-0068	Install Date: 09/01/2006	Natural Gas	1298386	2011-02-28	28	575	0	93
A05-0069	Premise : 414759		GAS-0069	Install Date: 09/05/2006	Natural Gas	1178545	2011-02-28	28	1,207	0	93
A05-0070	Premise : 608173		GAS-0070	Install Date: 09/05/2006	Natural Gas	1178545	2011-02-28	28	759	0	93
A05-0072	Premise : 248451		GAS-0072	Install Date: 10/27/2006	Natural Gas	497887	2010-08-31	31	98	0	274
A05-0077	Premise : 64492		GAS-0077	Install Date: 11/22/2006	Natural Gas	358232	2011-02-10	29	184	0	111
A05-0079	Premise : 606229		GAS-0079	Install Date: 07/07/2006	Natural Gas	772955	2010-12-01	30	532	0	182
A05-0080	Premise : 256346		GAS-0080	Install Date: 08/31/2006	Natural Gas	1121989	2011-02-28	28	256	0	93
A05-0081	Premise : 286361		GAS-0081	Install Date: 09/13/2006	Natural Gas	1696560	2011-02-28	28	2,955	0	93
A05-0082	Premise : 285146		GAS-0082	Install Date: 10/26/2006	Natural Gas	1696560	2011-02-28	28	818	0	93
A05-0084	Premise : 645039		GAS-0084	Install Date: 10/18/2006	Natural Gas	772342	2011-03-16	29	84	0	77
A05-0085	Premise : 525780		GAS-0085	Install Date: 07/05/2006	Natural Gas	647014	2011-02-04	60	715	0	117
A05-0086	Premise : 191021		GAS-0086	Install Date: 05/31/2007	Natural Gas	318777	2011-03-16	29	1,193	0	77
A05-0087	Premise : 779272		GAS-0087	Install Date: 01/16/2007	Natural Gas	1179883	2011-02-28	28	538	0	93
A05-0089	Premise : 45157		GAS-0089	Install Date: 11/26/2006	Natural Gas	1701887	2011-03-17	29	223	0	76
A05-0093	Premise : 285521		GAS-0093	Install Date: 11/01/2006	Natural Gas	623591	2011-02-28	28	321	0	93
A05-0094	Premise : 508110		GAS-0094	Install Date: 09/01/2006	Natural Gas	1196426	2010-11-04	31	141	0	209
A05-0095	Premise : 160979		GAS-0095	Install Date: 08/01/2007	Natural Gas	267929	2011-03-03	29	418	0	90
A05-0096	Premise : 51072		GAS-0096	Install Date: 08/11/2006	Natural Gas	168568	2011-03-04	30	262	0	89

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site			Meter				Last Reading				
Name	Description	Code	Name	Description	Type	Account Number	Date	Days	Consumption	Cost	Days Since
A05-0098	Premise : 782766		GAS-0098	Install Date: 12/16/2006	Natural Gas	1179918	2011-03-28	28	677	0	65
A05-0099	Premise : 652994		GAS-0099	Install Date: 10/12/2006	Natural Gas	1179439	2011-02-28	28	872	0	93
A05-0100	Premise : 771423		GAS-0100	Install Date: 12/07/2006	Natural Gas	950726	2011-03-08	60	371	0	85
A05-0101	Premise : 266117		GAS-0101	Install Date: 12/07/2006	Natural Gas	1891403	2011-03-25	29	222	0	68
A05-0102	Premise : 702112		GAS-0102	Install Date: 06/01/2007	Natural Gas	1179472	2011-02-28	28	3,861	0	93
A05-0103	Premise : 449169		GAS-0103	Install Date: 05/24/2007	Natural Gas	647243	2011-03-03	29	217	0	90
A05-0104	Premise : 483716		GAS-0104	Install Date: 04/19/2007	Natural Gas	1696560	2011-02-28	28	229	0	93
A05-0105	Premise : 266076		GAS-0105	Install Date: 04/27/2007	Natural Gas	647243	2011-02-01	32	264	0	120
A05-0106	Premise : 265806		GAS-0106	Install Date: 04/27/2007	Natural Gas	1696560	2011-02-28	28	325	0	93
A05-0109	Premise : 313159		GAS-0109	Install Date: 11/03/2006	Natural Gas	656898	2011-03-08	60	264	0	85
A05-0110	Premise : 721346		GAS-0110	Install Date: 10/12/2006	Natural Gas	1300786	2011-02-28	28	330	0	93
A05-0112	Premise : 505743		GAS-0112	Install Date: 10/18/2006	Natural Gas	1178736	2011-02-28	28	509	0	93
A05-0114	Premise : 290590		GAS-0114	Install Date: 01/29/2007	Natural Gas	1696560	2011-02-28	28	979	0	93
A05-0115	Premise : 257082		GAS-0115	Install Date: 04/18/2007	Natural Gas	1696560	2011-02-28	28	600	0	93
A05-0116	Premise : 737983		GAS-0116	Install Date: 04/18/2007	Natural Gas	1240604	2011-03-09	29	383	0	84
A05-0119	Premise : 279229		GAS-0119	Install Date: 06/28/2007	Natural Gas	1178600	2011-02-28	28	984	0	93
A05-0120	Premise : 480833		GAS-0120	Install Date: 04/25/2007	Natural Gas	1037859	2011-03-09	29	711	0	84
A05-0122	Premise : 330288		GAS-0122	Install Date: 12/01/2006	Natural Gas	711233	2011-02-28	28	476	0	93
A05-0123	Premise : 473191		GAS-0123	Install Date: 10/01/2007	Natural Gas	734697	2011-02-07	62	467	0	114
A05-0125	Premise : 309195		GAS-0125	Install Date: 08/05/2008	Natural Gas	623999	2011-03-29	29	242	0	64
A05-0131	Premise : 257372		GAS-0131	Install Date: 05/01/2007	Natural Gas	1178474	2011-02-28	28	2,878	0	93
A05-0132	Premise : 688856		GAS-0132	Install Date: 10/01/2008	Natural Gas	798495	2011-03-22	29	231	0	71
A05-0133	Premise : 785675		GAS-0133	Install Date: 09/01/2007	Natural Gas	1179701	2011-02-28	28	426	0	93
A05-0134	Premise : 541514		GAS-0134	Install Date: 09/24/2007	Natural Gas	1178602	2011-02-28	28	557	0	93
A05-0136	Premise : 299702		GAS-0136	Install Date: 10/01/2007	Natural Gas	1323619	2011-02-28	28	561	0	93
A05-0137	Premise : 478417		GAS-0137	Install Date: 09/01/2007	Natural Gas	1323616	2011-02-28	28	648	0	93
A05-0138	Premise : 420870		GAS-0138	Install Date: 09/01/2007	Natural Gas	1323620	2011-02-28	28	254	0	93
A05-0140	Premise : 365653		GAS-0140	Install Date: 11/21/2007	Natural Gas	665969	2011-02-28	28	796	0	93
A05-0144	Premise : 496208		GAS-0144	Install Date: 07/25/2007	Natural Gas	498924	2011-03-02	28	308	0	91
A05-0150	Premise : 295067		GAS-0150	Install Date: 08/01/2007	Natural Gas	623719	2011-03-29	32	356	0	64
A05-0154	Premise : 515881		GAS-0154	Install Date: 04/07/2008	Natural Gas	1580407	2011-03-09	29	331	0	84
A05-0155	Premise : 536113		GAS-0155	Install Date: 07/17/2007	Natural Gas	1178582	2011-02-28	28	648	0	93
A05-0156	Premise : 302558		GAS-0156	Install Date: 04/05/2008	Natural Gas	1178576	2011-02-28	28	1,871	0	93
A05-0159	Premise : 423566		GAS-0159	Install Date: 08/30/2007	Natural Gas	640106	2011-02-14	62	408	0	107
A05-0163	Premise : 605934		GAS-0163	Install Date: 11/02/2007	Natural Gas	772334	2011-03-02	29	899	0	91

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site			Meter				Last Reading				
Name	Description	Code	Name	Description	Type	Account Number	Date	Days	Consumption	Cost	Days Since
A05-0169	Premise : 272939		GAS-0169	Install Date: 04/03/2008	Natural Gas	1868083	2011-02-28	28	793	0	93
A05-0171	Premise : 197335		GAS-0171	Install Date: 10/01/2008	Natural Gas	298535	2011-02-28	28	469	0	93
A05-0173	Premise : 14291		GAS-0173	Install Date: 09/01/2008	Natural Gas	127587	2011-02-18	30	203	0	103
A05-0174	Premise : 10891		GAS-0174	Install Date: 09/02/2008	Natural Gas	127587	2011-03-09	30	222	0	84
A05-0176	Premise : 510439		GAS-0176	Install Date: 05/01/2009	Natural Gas	742126	2010-12-31	30	643	0	152
A05-0177	Premise : 307218		GAS-0177	Install Date: 07/01/2009	Natural Gas	498155	2010-11-29	62	360	0	184
A05-0178	Premise : 161485		GAS-0178	Install Date: 09/01/2009	Natural Gas	268955	2011-03-02	5	81	0	91
A05-0180	Premise : 304568		GAS-0180	Install Date: 05/22/2009	Natural Gas	498108	2011-03-28	31	529	0	65
A05-0181	Premise : 490831		GAS-0181	Install Date: 09/01/2009	Natural Gas	1126956	2011-03-31	29	256	0	62
A05-0183	Premise : 482862		GAS-0183	Install Date: 06/01/2009	Natural Gas	736951	2011-03-10	29	93	0	83
A05-0184	Premise : 325339		GAS-0184	Install Date: 11/04/2009	Natural Gas	692350	2011-03-21	31	300	0	72
A05-0185	Premise : 399907		GAS-0185	Install Date: 11/02/2009	Natural Gas	1178545	2010-11-30	30	1,090	0	183
A05-0188	Premise : 948964		GAS-0188	Install Date: 09/01/2009	Natural Gas	1650898	2011-03-11	29	1,897	0	82
A05-0189	Premise : 562819		GAS-0189	Install Date: 07/02/2009	Natural Gas	858120	2011-03-25	58	496	0	68
A05-0190	Premise : 462258		GAS-0190	Install Date: 10/01/2009	Natural Gas	564349	2011-02-28	28	150	0	93
A05-0192	Premise : 267973		GAS-0192	Install Date: 11/17/2009	Natural Gas	1862457	2011-03-29	29	209	0	64
A05-0193	Premise : 309516		GAS-0193	Install Date: 06/29/2009	Natural Gas	655948	2011-03-07	60	554	0	86
A05-0195	Premise : 726355		GAS-0195	Install Date: 09/23/2009	Natural Gas	1180024	2011-02-28	28	503	0	93
A05-0196	Premise : 325654		GAS-0196	Install Date: 06/09/2009	Natural Gas	692347	2011-02-18	63	501	0	103
A05-0197	Premise : 326188		GAS-0197	Install Date: 06/09/2009	Natural Gas	692347	2011-02-18	63	525	0	103
A05-0206	Premise : 345442		GAS-0206	Install Date: 06/01/2009	Natural Gas	661463	2011-02-28	28	476	0	93
A05-0210	Premise : 541687		GAS-0210	Install Date: 11/06/2009	Natural Gas	1178607	2011-02-28	28	1,141	0	93
A05-0212	Premise : 675822		GAS-0212	Install Date: 12/03/2009	Natural Gas	1139860	2011-02-03	29	446	0	118
A05-0213	Premise : 675784		GAS-0213	Install Date: 12/03/2009	Natural Gas	1139861	2011-03-04	29	440	0	89
A05-0214	Premise : 676296		GAS-0214	Install Date: 11/30/2009	Natural Gas	795104	2010-11-29	32	118	0	184
A05-0217	Premise : 67113		GAS-0217	Install Date: 08/12/2009	Natural Gas	323616	2011-02-17	62	26	0	104
A05-0219	Premise : 288862		GAS-0219	Install Date: 12/04/2009	Natural Gas	1777251	2011-03-29	32	121	0	64
A05-0228	Premise : 285568		GAS-0228	Install Date: 11/01/2009	Natural Gas	623592	2011-03-28	31	277	0	65
A10-0247	Premise : 703441		GAS-0247	Install Date: 10/06/2009	Natural Gas	1179124	2011-02-28	28	1,908	0	93
A10-0251	Premise : 306259		GAS-0251	Install Date: 11/01/2009	Natural Gas	1037617	2010-11-30	33	402	0	183
A10-0253	Premise : 58610		GAS-0253	Install Date: 12/15/2009	Natural Gas	1946680	2011-03-09	28	278	0	84

APPENDIX D: Survey Questions

Q1. How many boilers did you have prior to the Efficient Boiler Retrofit Program?

NUMBER OF BOILERS: ________

Q2. How many of these boilers were replaced through the Efficient Boiler Retrofit Program?

NUMBER OF BOILERS: ________

Q3. What proportion of the overall load is served by the retrofitted heating plant? Please answer in "percent of floor area".

PERCENT OF FLOOR AREA: ______%

Q4. Which of the following are part of the facility where the new boiler was installed?

Pool
Gas-fired cooking
Radiant heating
Domestic hot water
Reheat coils
Air handling unit coils
Other (please specify): ____________

Q5. What elements of this building are not impacted by the retrofit? That is, they burn natural gas themselves, or they have a separate boiler or other source of heat.

Kitchen
Domestic hot water
Roof top unit (gas fired)
Other (please specify): ____________

Q6. Which of the following best describes your retrofit?

Boiler replacement only
Boiler replacement plus enhanced controls
Other plant upgrades such as piping and distribution update (please specify): ____________

Q7. Were any other energy management measures implemented at the same time as the boiler retrofit? READ LIST

Window replacement
Door replacement
Installing additional insulation
Redesign of HVAC system (fan coils, air handling units)
Zone isolation
Heat recovery
Direct digital control

Other (please specify): ____________

Q8. Have you noticed a change in maintenance requirements or expenditures following the retrofit?

Yes, increased
Yes, decreased
No change
DON'T KNOW

Q9. Finally, how would you rate your satisfaction or dissatisfaction with Efficient Boiler Retrofit program? Please think about your organization's experience with the process and the program overall.

Very satisfied
Somewhat satisfied
NEITHER (DO NOT READ)
Somewhat dissatisfied
Very dissatisfied

Q10. Why are you _______________?

OPEN END

Q11. Finally, please imagine that your organization had not been offered a financial incentive to participate in the Efficient Boiler Retrofit program. In that scenario, based on what you know about your organization, would you have completed the retrofit?

Yes
No

Q12. Why? What would have been the biggest incentive / barrier to completing the retrofit.

OPEN END

Q13. Terasen would like to attach your responses to these questions to your account in order more fully understand the impact of the retrofit to your overall usage. Your responses to these questions will be used only for this purpose and all your information including your answers to these questions will remain confidential. Do I have your permission to provide Terasen with your responses to my questions?

APPENDIX E: Survey Results

Survey Question	Results*		
1. How many boilers did you have prior to the Efficient Boiler Retrofit Program?		2	Average response
2. How many of these boilers were replaced through the Efficient Boiler Retrofit Program?		2	Average response
		79%	Replaced all of their boilers using the Efficient Boiler Retrofit Program.
3. What proportion of the overall load is served by the retrofitted heating plant?		88%	Average response
4. Which of the following are part of the facility where the new boiler was installed? **	4%	2	Pool
	4%	2	Gas-fired cooking
	12%	6	Other
	33%	16	Reheat coils
	39%	19	Air handling unit coils
	49%	24	Radiant heating
	82%	40	Domestic hot water
5. What elements of this building are not impacted by the retrofit?	10%	5	Other
	10%	5	Rooftop Unit (Gas fired)
	10%	5	Domestic Hot Water
	12%	6	Kitchen
	57%	28	No response
	100%	**49**	**Total**

* Percentages may not total 100% due to rounding.
** Percentages do not total 100%, because question asked for multiple responses.

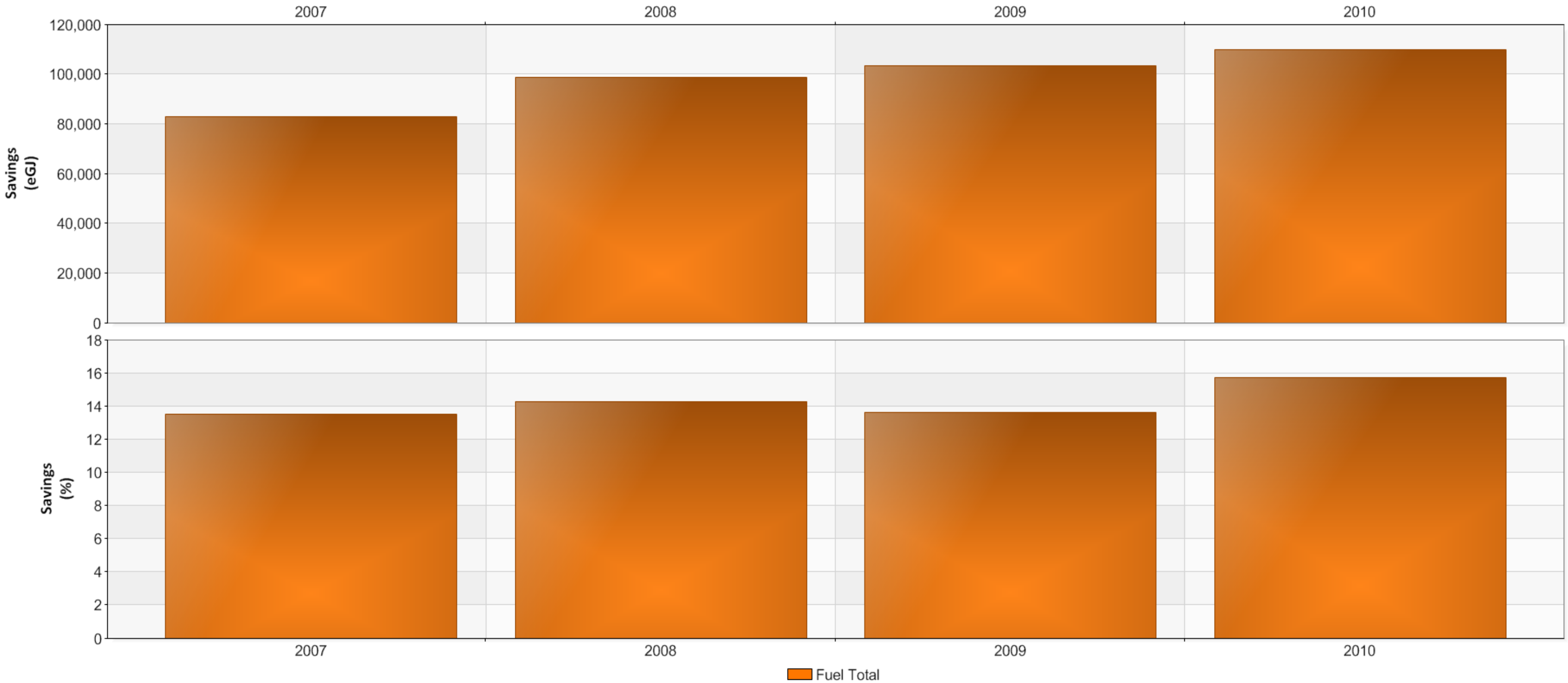
Survey Question	Results*		
	22%	10	Other Upgrades
	35%	17	Boiler Only
	45%	22	Boiler and Controls
	100%	**49**	**Total**
7. Were any other energy management measures implemented at the same time as the boiler retrofit? **			
	4%	2	Door replacement
	4%	2	Window replacement
	4%	2	Heat recovery
	6%	3	Installing additional insulation
	10%	5	Zone isolation
	12%	6	Other
	24%	12	Redesign of HVAC system
	37%	18	Direct digital control
	45%	22	No response
8. Have you noticed a change in maintenance requirements or expenditures following the retrofit?			
	2%	1	Yes, increased
	73%	33	Yes, decreased
	13%	6	No change
	11%	5	Don't know
	100%	**45**	**Total**
9. How would you rate your satisfaction or dissatisfaction with Efficient Boiler Retrofit program?			
	82%	40	Very satisfied
	16%	8	Somewhat satisfied
	2%	1	Very dissatisfied
	100%	**49**	**Total**

Survey Question	Results*		
10. Why?	· Easy application; process simple; quick; fast getting approval · Satisfied because of strong personalized support. · Process is quick and approval is fast · Very satisfied because the retrofit reduced operating costs and greenhouse emissions. · Easier if final payments could be predicted like with the small boiler incentive.		
11. If your organization had not been offered a financial incentive, would you have completed the retrofit?	69%	34	Yes
	31%	15	No
	100%	**49**	**Total**
12. Why? What would have been the biggest incentive / barrier to completing the retrofit.	Yes	· May have been delayed longer but $ and CO2 Savings primary driver. · Equipment needed to be replaced because it was too old. · Yes because of payback cost and its simplicity. No barriers to completing retrofit.	
	No	· Incentive persuaded them to do it, financial cost would have been a barrier. · They would have gone with a less expensive boiler.	

APPENDIX F: Annual Energy Savings

Annual Energy Savings: Project (2007 - 2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**



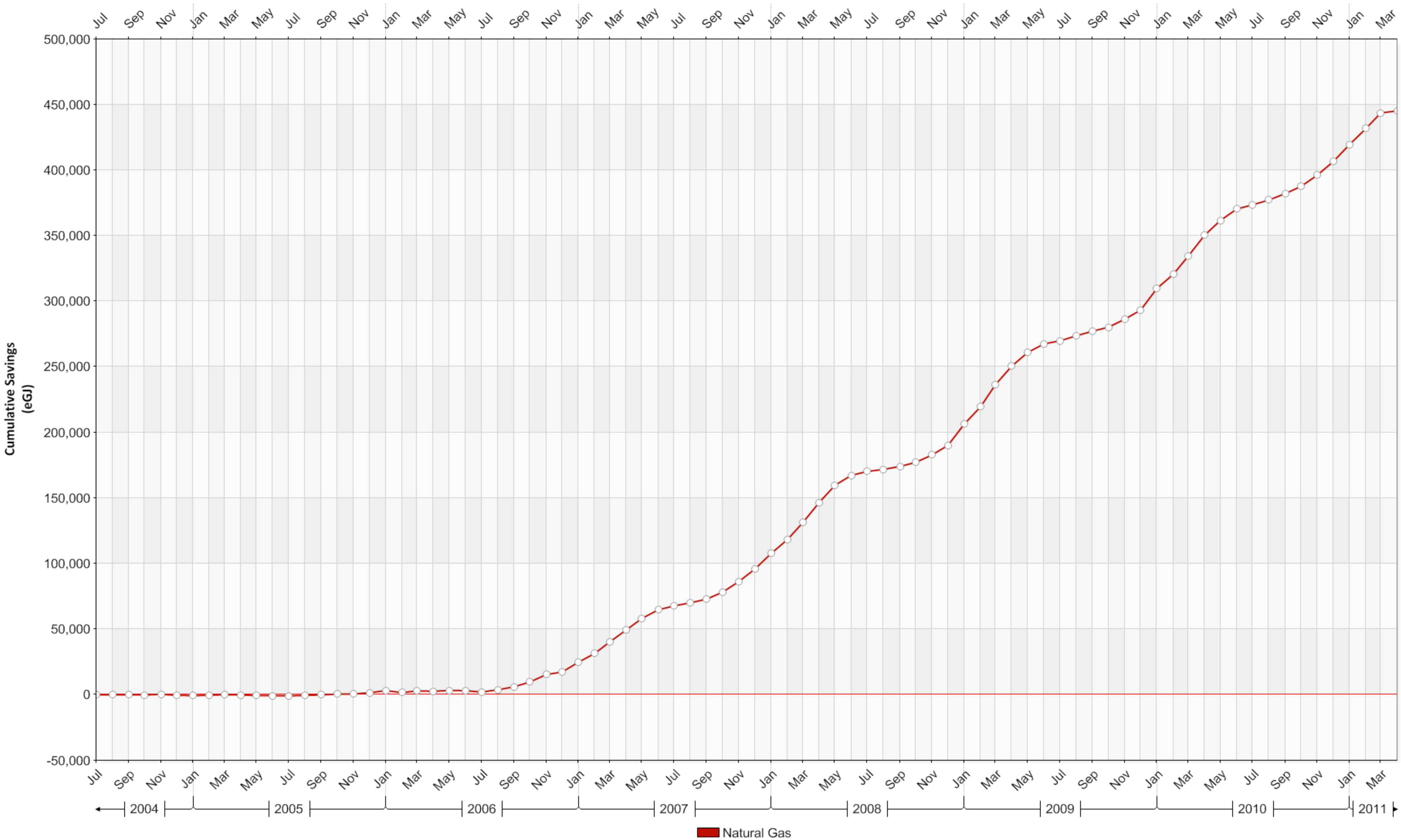
Year[1]	Fuel Total			
	Prorated Actual	Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2007	531,179	614,081	82,901	14
2008	591,415	690,093	98,678	14
2009	655,617	759,086	103,470	14
2010	588,922	698,693	109,771	16
Total:	**2,367,133**	**2,761,953**	**394,820**	**14**

[1] "Year" refers to fiscal year ending in December
Brown indicates missing data and Blue indicates prorated data.

APPENDIX G: CUSUM – Project

CUSUM: Project

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**



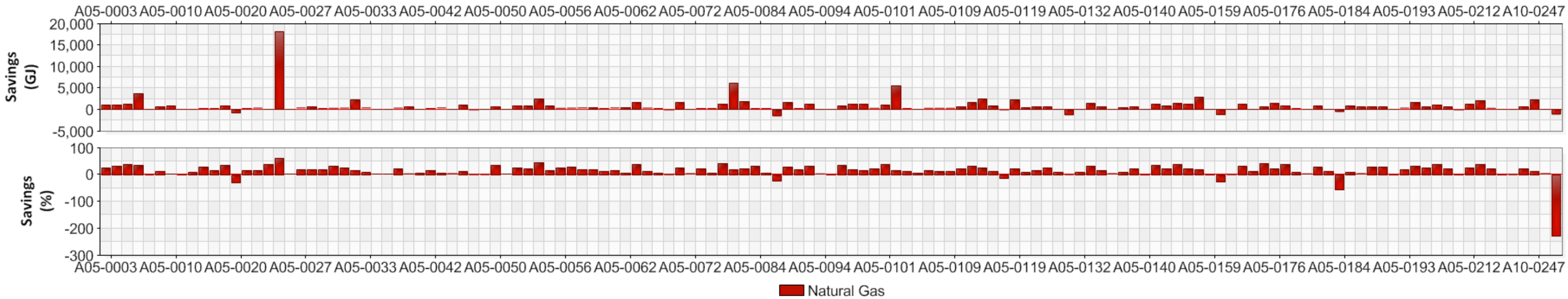
APPENDIX H: CUSUM – Site

(Due to large file size, this Appendix is provided as a separate file)

APPENDIX I: Savings By Year By Site

Savings By Year By Site (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Year: **2010**



Site		Natural Gas			
Name	Description	Prorated Actual GJ	Baseline GJ	Savings Abs. GJ	Savings %
A05-0003	Premise : 406662	3,687	4,839	1,152	24
A05-0004	Premise : 254236	2,534	3,640	1,106	30
A05-0005	Premise : 610023	1,967	3,188	1,221	38
A05-0006	Premise : 704208	7,444	11,203	3,760	34
A05-0007	Premise : 51073	5,307	5,170	-136	-3
A05-0008	Premise : 280132	4,758	5,432	675	12
A05-0010	Premise : 266683	39,283	40,216	933	2
A05-0011	Premise : 468596	5,656	5,631	-25	0
A05-0012	Premise : 387051	1,163	1,285	122	10
A05-0015	Premise : 472188	589	809	221	27
A05-0017	Premise : 684089	1,276	1,506	230	15
A05-0019	Premise : 256597	1,835	2,795	960	34
A05-0020	Premise : 413028	3,166	2,451	-715	-29
A05-0021	Premise : 399773	1,187	1,387	201	14
A05-0022	Premise : 311848	2,262	2,663	401	15
A05-0023	Premise : 35729	229	373	145	39
A05-0024	Premise : 705498	11,633	29,708	18,075	61
A05-0026	Premise : 423077	812	827	15	2
A05-0027	Premise : 525328	1,754	2,199	444	20

Brown indicates missing data and Blue indicates prorated data.

Savings By Year By Site (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Year: **2010**

Site		Natural Gas			
		Prorated Actual	Baseline	Savings	
Name	Description	GJ	GJ	Abs. GJ	%
A05-0028	Premise : 545094	2,984	3,679	695	19
A05-0029	Premise : 617167	1,453	1,754	301	17
A05-0030	Premise : 290739	777	1,125	347	31
A05-0031	Premise : 318638	1,245	1,682	437	26
A05-0032	Premise : 612048	12,664	15,004	2,340	16
A05-0033	Premise : 310861	3,961	4,421	460	10
A05-0034	Premise : 522033	106	109	2	2
A05-0035	Premise : 236764	1,723	1,780	57	3
A05-0037	Premise : 313476	1,519	1,923	403	21
A05-0040	Premise : 811250	17,500	18,118	619	3
A05-0041	Premise : 308349	1,155	1,226	71	6
A05-0042	Premise : 308141	1,126	1,320	194	15
A05-0043	Premise : 670431	7,192	7,676	484	6
A05-0044	Premise : 388193	1,208	1,264	56	4
A05-0045	Premise : 317893	7,669	8,701	1,032	12
A05-0046	Premise : 311883	7,398	7,054	-344	-5
A05-0048	Premise : 403864	1,680	1,604	-76	-5
A05-0050	Premise : 360590	1,197	1,862	666	36
A05-0051	Premise : 409296	5,254	5,382	128	2
A05-0052	Premise : 304098	2,900	3,873	973	25
A05-0053	Premise : 282017	3,239	4,073	834	20
A05-0054	Premise : 332426	3,126	5,622	2,495	44
A05-0055	Premise : 332435	4,941	5,802	861	15
A05-0056	Premise : 332417	1,115	1,464	349	24
A05-0057	Premise : 332425	1,004	1,406	402	29
A05-0058	Premise : 332349	1,908	2,365	456	19
A05-0059	Premise : 332382	2,150	2,680	530	20
A05-0060	Premise : 332383	2,042	2,366	324	14
A05-0061	Premise : 332384	2,421	2,892	472	16
A05-0062	Premise : 522363	8,195	8,777	582	7
A05-0065	Premise : 275850	2,904	4,634	1,730	37

Brown indicates missing data and Blue indicates prorated data.

Savings By Year By Site (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Year: **2010**

Site		Natural Gas			
		Prorated Actual	Baseline	Savings	
Name	Description	GJ	GJ	Abs. GJ	%
A05-0066	Premise : 30724	2,916	3,334	418	13
A05-0068	Premise : 307235	3,972	4,273	301	7
A05-0069	Premise : 414759	9,120	8,777	-343	-4
A05-0070	Premise : 608173	5,443	7,187	1,744	24
A05-0072	Premise : 248451	1,699	1,784	85	5
A05-0077	Premise : 64492	921	1,186	265	22
A05-0079	Premise : 606229	4,432	4,705	273	6
A05-0080	Premise : 256346	1,763	2,995	1,232	41
A05-0081	Premise : 286361	27,610	33,732	6,122	18
A05-0082	Premise : 285146	6,630	8,527	1,896	22
A05-0084	Premise : 645039	489	729	240	33
A05-0085	Premise : 525780	2,815	3,013	197	7
A05-0086	Premise : 191021	8,340	6,830	-1,510	-22
A05-0087	Premise : 779272	3,982	5,601	1,619	29
A05-0089	Premise : 45157	1,267	1,534	267	17
A05-0093	Premise : 285521	2,894	4,159	1,265	30
A05-0094	Premise : 508110	1,341	1,396	54	4
A05-0095	Premise : 160979	3,566	3,526	-40	-1
A05-0096	Premise : 51072	1,615	2,435	821	34
A05-0098	Premise : 782766	5,630	6,934	1,303	19
A05-0099	Premise : 652994	6,740	8,050	1,309	16
A05-0100	Premise : 771423	1,281	1,650	369	22
A05-0101	Premise : 266117	1,573	2,589	1,015	39
A05-0102	Premise : 702112	31,124	36,717	5,593	15
A05-0103	Premise : 449169	1,635	1,880	244	13
A05-0104	Premise : 483716	2,147	2,301	153	7
A05-0105	Premise : 266076	2,092	2,451	359	15
A05-0106	Premise : 265806	2,673	3,020	348	12
A05-0109	Premise : 313159	2,249	2,586	337	13
A05-0110	Premise : 721346	2,498	3,236	738	23
A05-0112	Premise : 505743	3,767	5,431	1,664	31

Brown indicates missing data and Blue indicates prorated data.

Savings By Year By Site (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Year: **2010**

Site		Natural Gas			
		Prorated Actual	Baseline	Savings	
Name	Description	GJ	GJ	Abs. GJ	%
A05-0114	Premise : 290590	8,115	10,651	2,537	24
A05-0115	Premise : 257082	5,242	6,037	794	13
A05-0116	Premise : 737983	2,821	2,489	-332	-13
A05-0119	Premise : 279229	7,507	9,817	2,310	24
A05-0120	Premise : 480833	4,899	5,389	490	9
A05-0122	Premise : 330288	4,111	4,859	748	15
A05-0123	Premise : 473191	1,774	2,373	599	25
A05-0125	Premise : 309195	2,258	2,437	179	7
A05-0131	Premise : 257372	25,637	24,396	-1,240	-5
A05-0132	Premise : 688856	1,466	1,581	116	7
A05-0133	Premise : 785675	3,189	4,688	1,499	32
A05-0134	Premise : 541514	4,124	4,843	719	15
A05-0136	Premise : 299702	4,078	4,253	175	4
A05-0137	Premise : 478417	4,695	5,187	492	9
A05-0138	Premise : 420870	2,131	2,758	627	23
A05-0140	Premise : 365653	6,740	6,766	26	0
A05-0144	Premise : 496208	2,559	3,912	1,353	35
A05-0150	Premise : 295067	2,864	3,682	818	22
A05-0154	Premise : 515881	2,184	3,592	1,408	39
A05-0155	Premise : 536113	4,507	5,824	1,317	23
A05-0156	Premise : 302558	12,775	15,728	2,954	19
A05-0159	Premise : 423566	1,388	1,362	-26	-2
A05-0163	Premise : 605934	5,652	4,489	-1,163	-26
A05-0169	Premise : 272939	3,472	3,284	-188	-6
A05-0171	Premise : 197335	2,954	4,315	1,360	32
A05-0173	Premise : 14291	1,262	1,428	166	12
A05-0174	Premise : 10891	1,058	1,809	751	42
A05-0176	Premise : 510439	5,292	6,854	1,562	23
A05-0177	Premise : 307218	1,697	2,683	986	37
A05-0178	Premise : 161485	2,160	2,395	234	10
A05-0180	Premise : 304568	3,623	3,749	126	3

Brown indicates missing data and Blue indicates prorated data.

Savings By Year By Site (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Year: **2010**

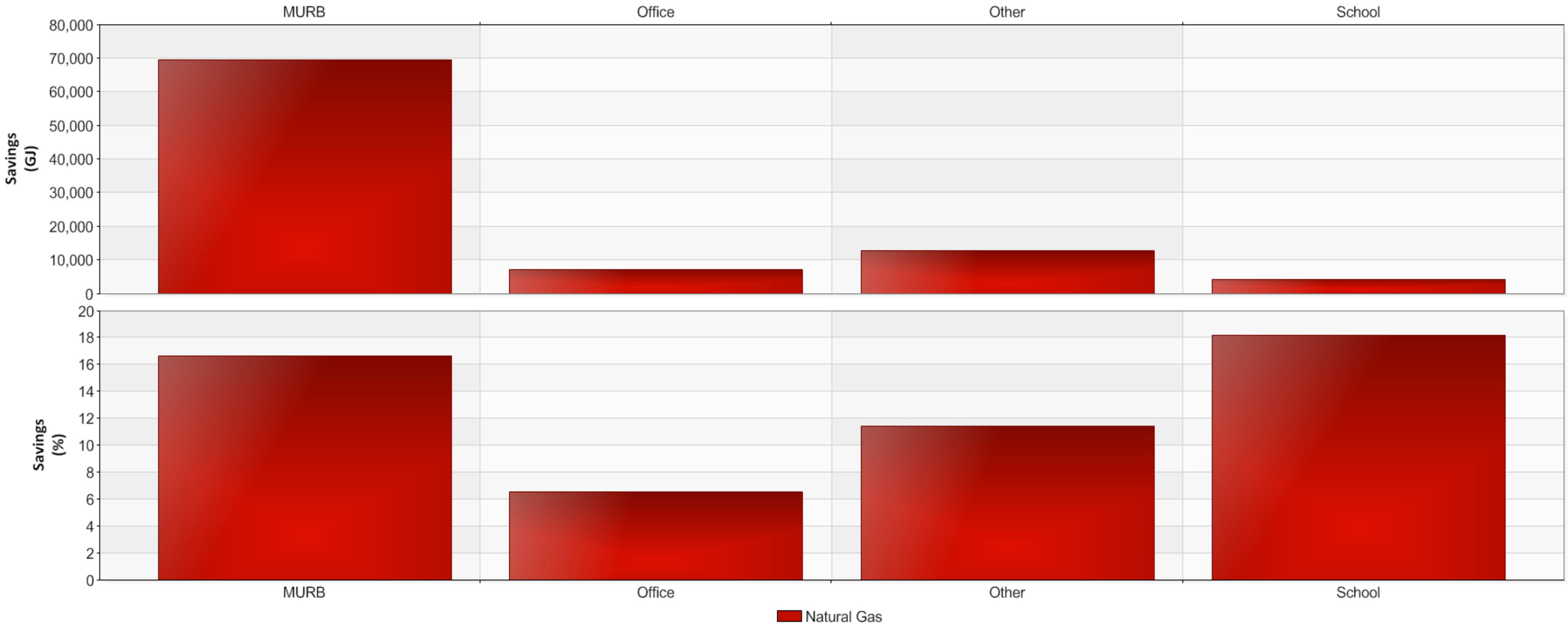
Site		Natural Gas			
		Prorated Actual	Baseline	Savings	
Name	Description	GJ	GJ	Abs. GJ	%
A05-0181	Premise : 490831	2,289	3,152	863	27
A05-0183	Premise : 482862	593	685	92	13
A05-0184	Premise : 325339	1,346	859	-487	-57
A05-0185	Premise : 399907	7,373	8,174	800	10
A05-0188	Premise : 948964	13,639	14,244	605	4
A05-0189	Premise : 562819	1,999	2,789	789	28
A05-0190	Premise : 462258	1,514	2,152	638	30
A05-0192	Premise : 267973	1,825	1,779	-46	-3
A05-0193	Premise : 309516	2,022	2,454	432	18
A05-0195	Premise : 726355	3,306	4,937	1,632	33
A05-0196	Premise : 325654	1,918	2,610	691	26
A05-0197	Premise : 326188	1,919	3,117	1,198	38
A05-0206	Premise : 345442	2,649	3,432	783	23
A05-0210	Premise : 541687	8,699	8,453	-246	-3
A05-0212	Premise : 675822	3,532	4,747	1,215	26
A05-0213	Premise : 675784	3,266	5,337	2,071	39
A05-0214	Premise : 676296	1,301	1,643	342	21
A05-0217	Premise : 67113	85	86	0	1
A05-0219	Premise : 288862	1,171	1,134	-37	-3
A05-0228	Premise : 285568	1,956	2,549	593	23
A10-0247	Premise : 703441	15,510	17,907	2,397	13
A10-0251	Premise : 306259	2,685	2,818	133	5
A10-0253	Premise : 58610	1,573	482	-1,091	-226
Total:		**588,922**	**698,693**	**109,771**	**16**

Brown indicates missing data and Blue indicates prorated data.

APPENDIX J: Savings By Year By Grouping 2010

Savings By Year By Grouping (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Year: **2010**



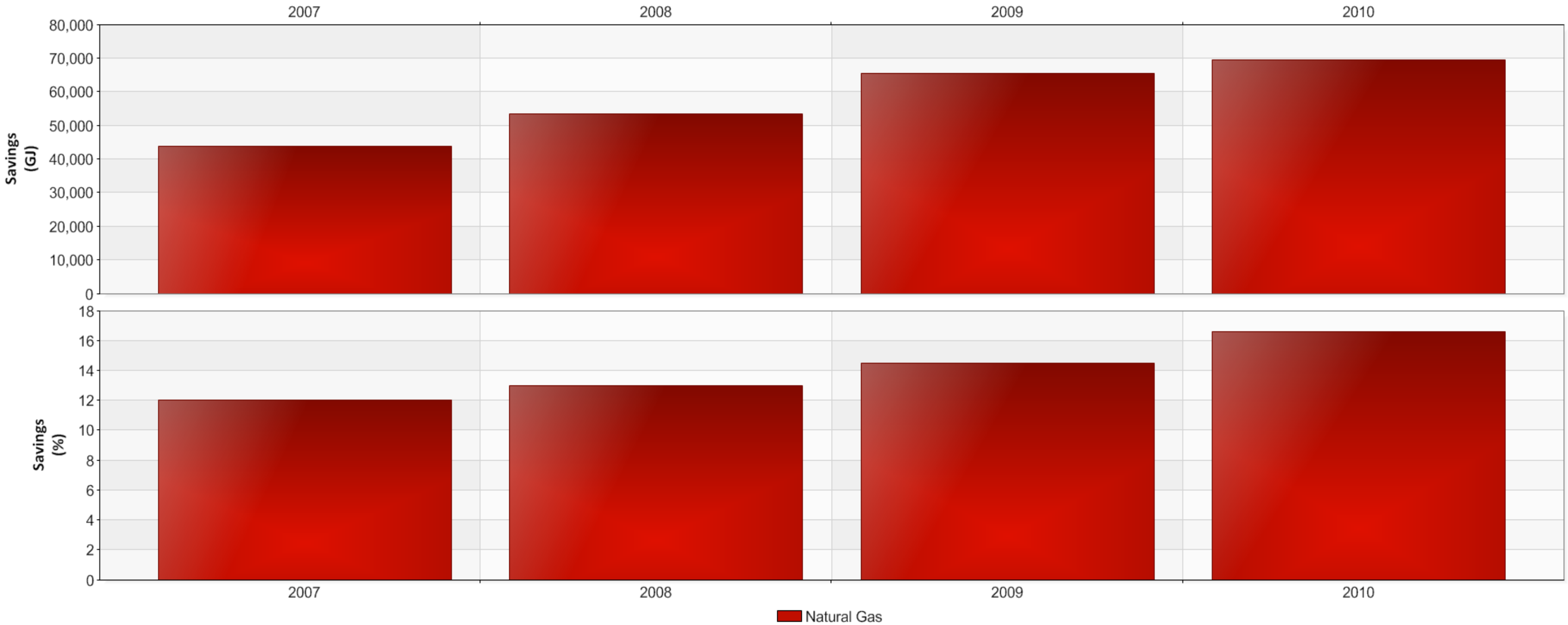
Grouping	Natural Gas Savings Abs. GJ	Natural Gas Savings %
MURB	69,582	17
Office	7,274	7
Other	12,774	11
School	4,359	18
Total:	**93,989**	**14**

Brown indicates missing data and Blue indicates prorated data.

APPENDIX K: Savings By Grouping By Year

Savings By Grouping By Year (2007 - 2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **MURB**

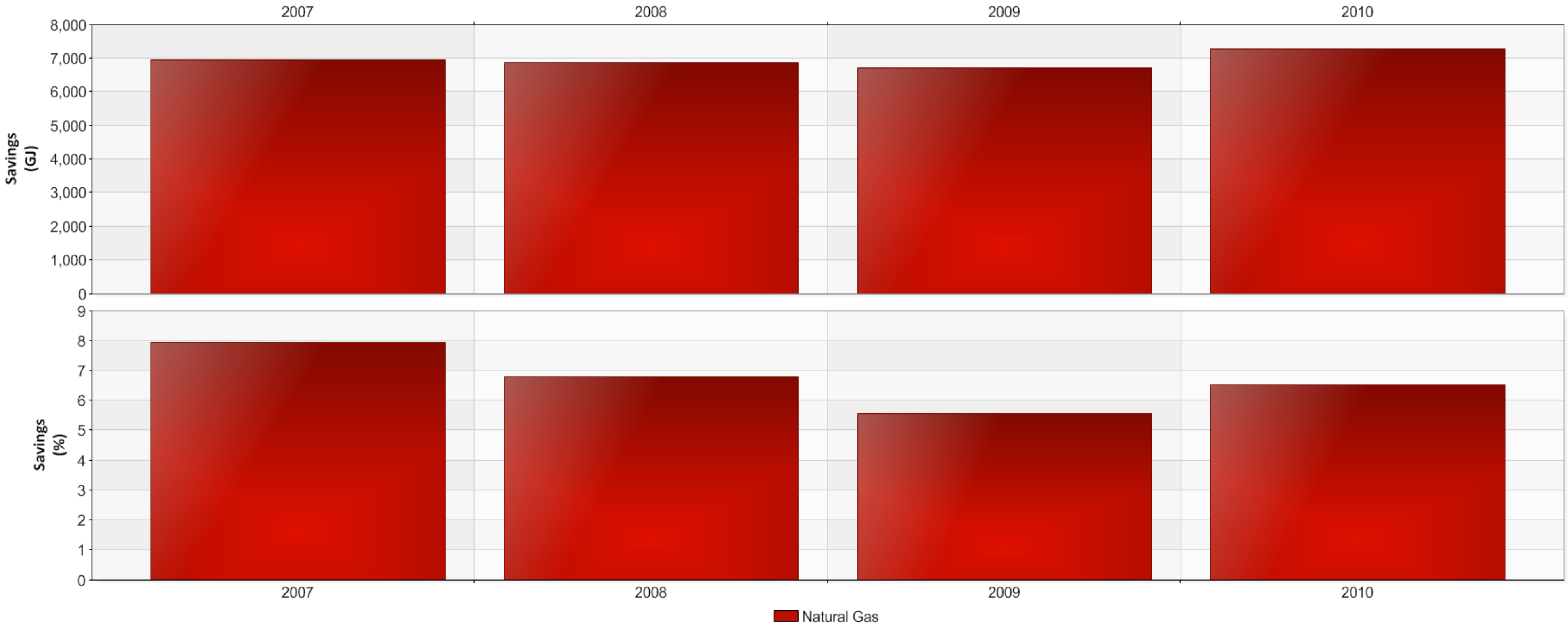


Year[1]	Natural Gas Savings Abs. GJ	Natural Gas Savings %
2007	43,989	12
2008	53,400	13
2009	65,604	15
2010	69,582	17
Total:	**232,575**	**14**

[1] "Year" refers to fiscal year ending in December
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year (2007 - 2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **Office**

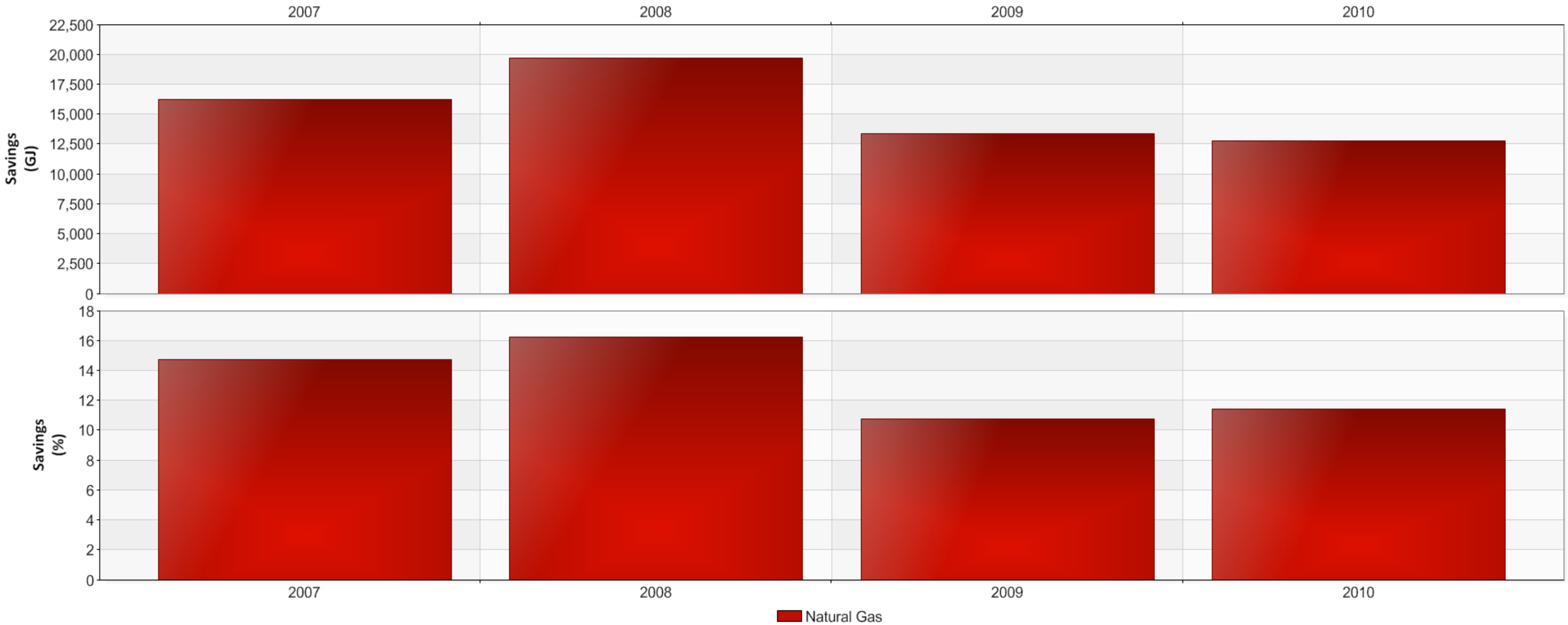


Year[1]	Natural Gas Savings Abs. GJ	Natural Gas Savings %
2007	6,948	8
2008	6,868	7
2009	6,717	6
2010	7,274	7
Total:	**27,807**	**7**

[1] "Year" refers to fiscal year ending in December
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year (2007 - 2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **Other**

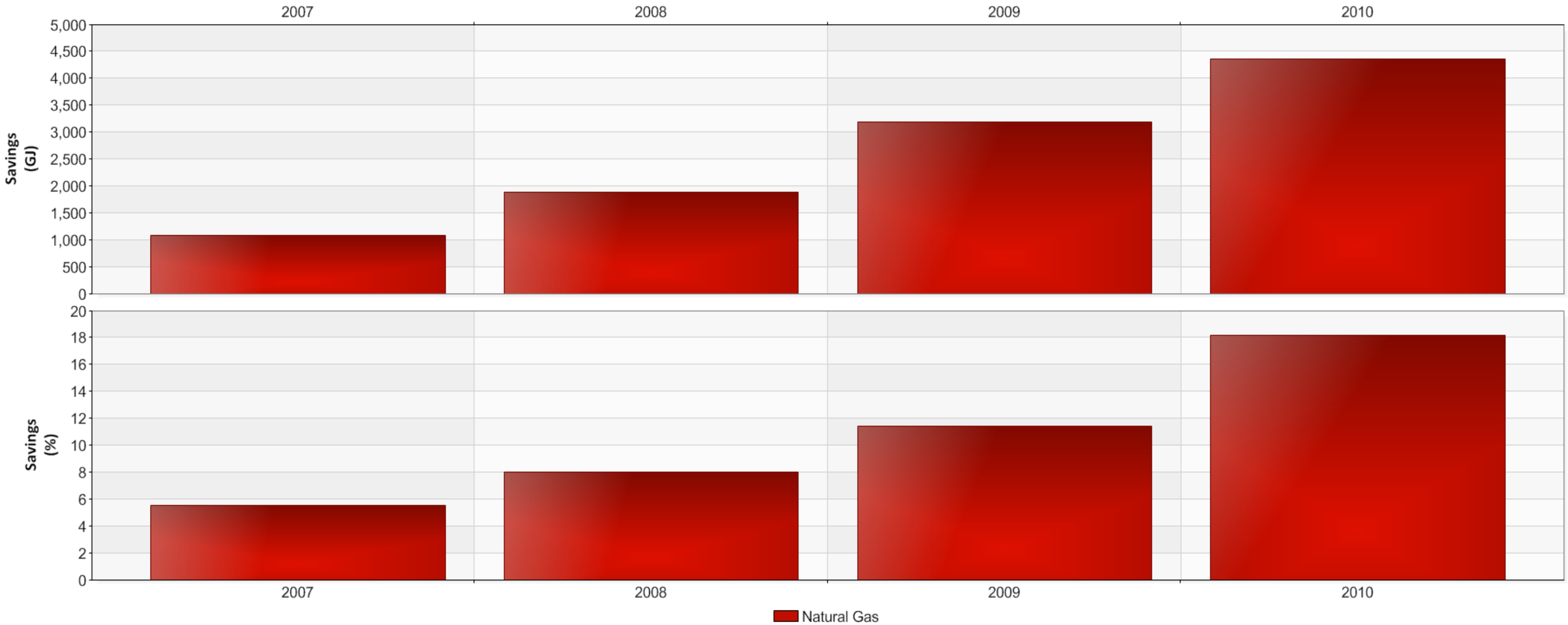


Year[1]	Natural Gas Savings Abs. GJ	Natural Gas Savings %
2007	16,282	15
2008	19,729	16
2009	13,363	11
2010	12,774	11
Total:	**62,148**	**13**

[1] "Year" refers to fiscal year ending in December
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year (2007 - 2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **School**



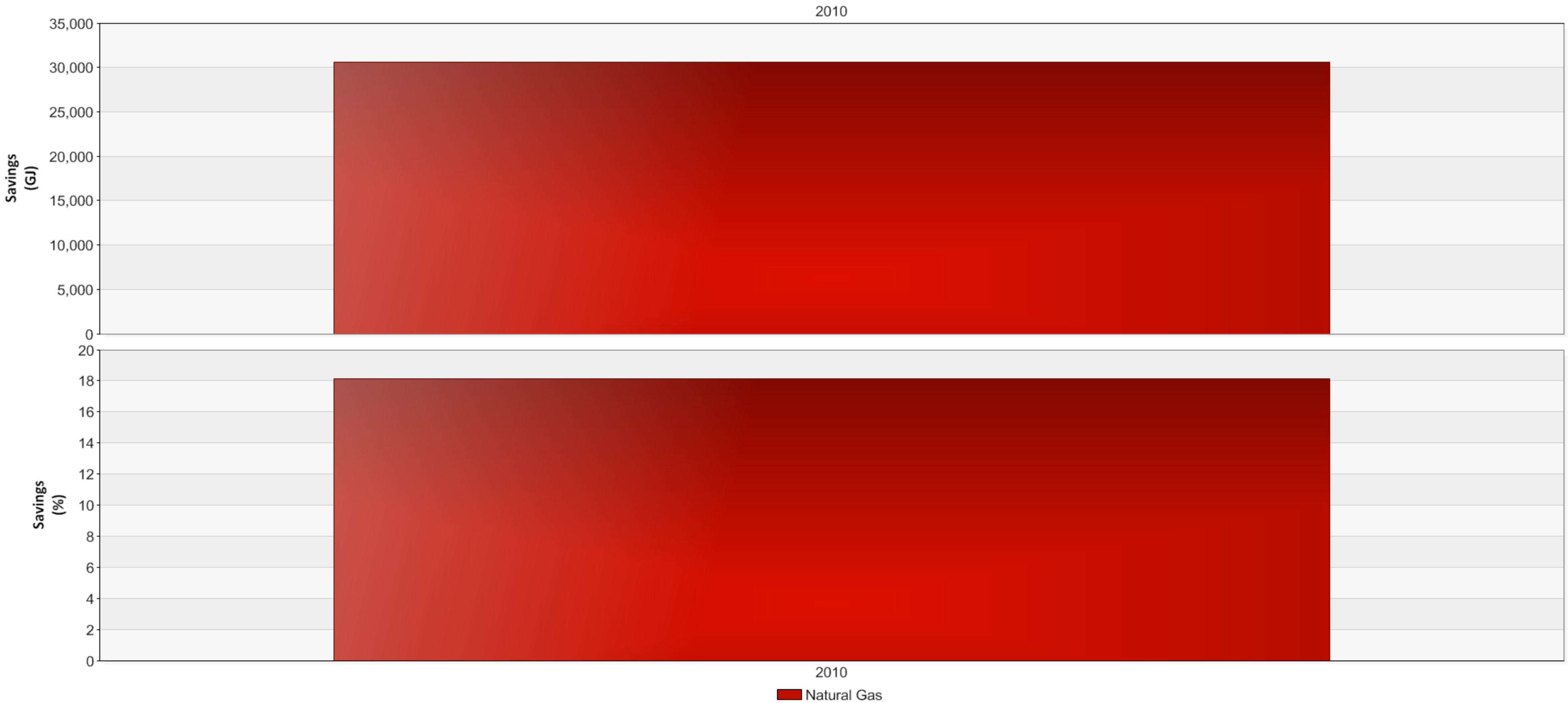
Year[1]	Natural Gas Savings Abs. GJ	Natural Gas Savings %
2007	1,082	6
2008	1,892	8
2009	3,198	11
2010	4,359	18
Total:	**10,531**	**11**

[1] "Year" refers to fiscal year ending in December
Brown indicates missing data and Blue indicates prorated data.

APPENDIX L: Savings By Boiler Efficiency Grouping By Year

Savings By Grouping By Year (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Boiler Efficiency**
Grouping: **High Efficiency**

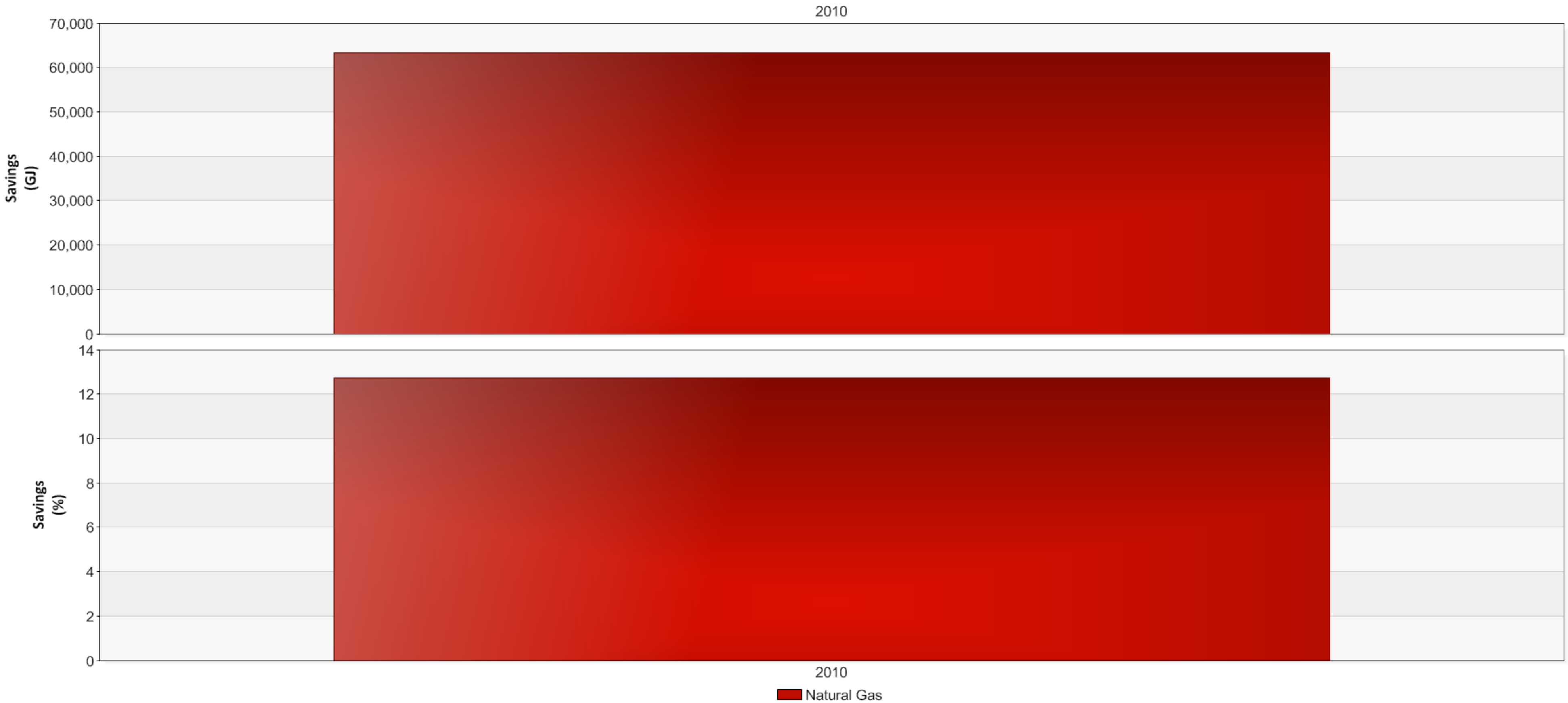


Year[1]	Natural Gas	
	Savings	
	Abs.	%
	GJ	
2010	30,657	18
Total:	**30,657**	**18**

[1] "Year" refers to fiscal year ending in December
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year (2010)

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Boiler Efficiency**
Grouping: **Mid Efficiency**



Year[1]	Natural Gas Savings Abs. GJ	%
2010	63,332	13
Total:	**63,332**	**13**

[1] "Year" refers to fiscal year ending in December
Brown indicates missing data and Blue indicates prorated data.

APPENDIX M: Statistical Analysis of Energy Savings by Building Type

Appendix: Statistical Analysis of Energy Savings by Building Type

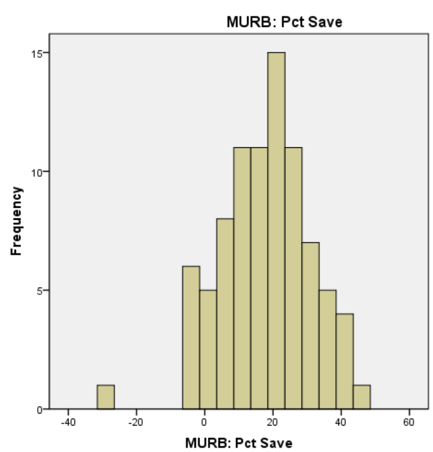
Prepared by Jonathan Berkowitz, Ph.D.
Berkowitz & Associates Consulting Inc.
4160 Staulo Crescent   Vancouver BC V6N 3S2
Tel: 604-263-1508   E-mail: jonathan.berkowitz@sauder.ubc.ca

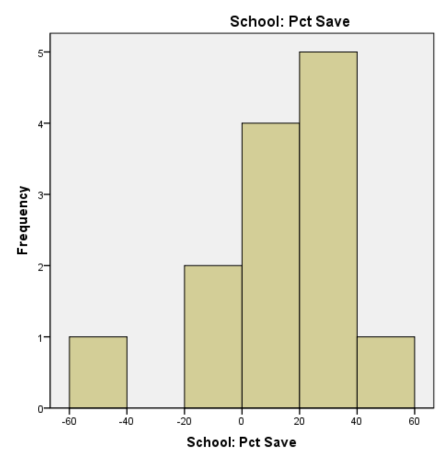
This appendix reports on detailed statistical analysis of the energy saving for each building type.

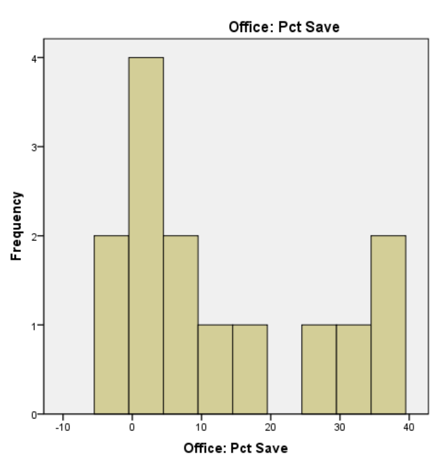
A. Graphical Displays of Distributions

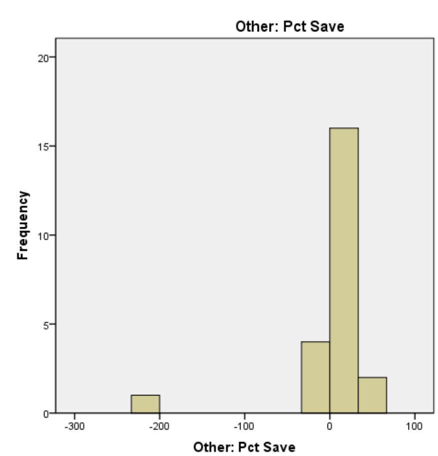
The following histograms provide a visual display of the distributions of energy saving (measured in percent) for each building type.

Since, sample sizes are very different across types -- 85 MURB buildings, 14 Office buildings, 13 Schools, and 23 Other buildings – so the histograms have somewhat different shapes.
The histograms for MURB, Schools, and Other, show gaps and hence statistical outliers. These will be investigated further, below.









B. Numerical Summaries

Typical or average levels of energy saving are provided by summary statistics of location, namely, the mean and the median:

- Mean = the "average" value; i.e. the centre of gravity of the distribution
- Median = the middle value; i.e. the value above which, and below which, 50% of values are located

Note that when the distribution is not symmetric, or when it includes outliers (i.e. extreme values), or both, then the mean and median made be substantially different. In fact, the mean is highly sensitive to the presence of extreme values.

Variability or spread in levels of energy saving are provided by summary statistics of dispersion, namely, the standard deviation and the interquartile range:

- Standard deviation (SD) = the typical or average distance from each value to the mean
- Interquartile Range (IQR) = the distance from the lower quartile (Q1), i.e. the 25th percentile, to the upper quartile (Q3), i.e. the 75th quartile. Hence IQR = Q3 – Q1

Note that since the standard deviation measures distance from the mean, it follows that the standard deviations will be highly sensitive to extreme values (just as the mean is). Specifically, the presence of extreme values will result in an inflated standard deviation.

The following table presents the numerical summaries, for each building type.

	MURB %Saving	*Office %Saving*	*School %Saving*	*Other %Saving*
Sample Size	85	14	13	23
Mean	17.6	12.8	14.3	1.0
Median	19.0	6.0	17.0	10.0
SD	13.0	14.1	26.5	52.9
Minimum	-29	-3	-57	-226
Maximum	44	37	42	61
Lower Quartile (Q1)	9.0	2.0	0.5	0.0
Upper Quartile (Q3)	25.5	28.0	33.5	23.0
IQR	16.5	26.0	33.0	23.0
Lower Inner Fence (Q1 – 1.5 x IQR)	-15.8	-37.0	-49.0	-34.5
Upper Inner Fence (Q3 + 1.5 x IQR)	50.2	67.0	83.0	57.5

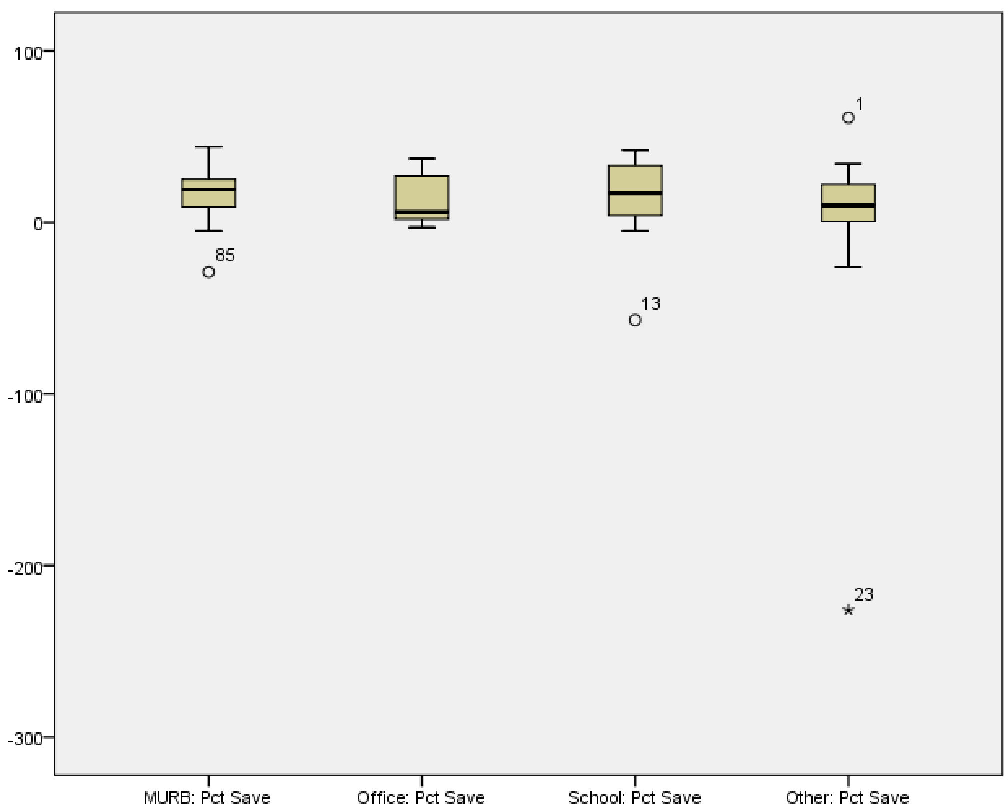
In the three small sample size building types, the difference between the mean and median is quite pronounced, especially for the "Other" type. And the inflated standard deviation is most evident for the School and Other types, where the minimum values are -57 and -226, respectively.

C. Outlier Identification and Boxplots

An objective method (developed by John Tukey) of identifying outliers is provided by the concept of "fences" which use quartiles and the interquartile range. Data values falling below (Q1 – 1.5 x IQR) or above (Q3 + 1.5 x IQR) are considered to be unusual values (i.e. outliers). Using this criterion, the outliers for each building type are:

- MURB: A05-0020 = -29% (Unusually Low)
- Office: None
- School: A05-0184 = -57% (Unusually Low)
- Other: A10-0253 = -226% (Unusually Low); A05-0024 = 61% (Unusually High)

A graphical device called a box plot provides a convenient visual display of a distribution along with identified outliers (using the fences criterion). The box shows the location of the lower quartile (the lower end of the box), median (the line segment in the interior of the box) and the upper quartile (the upper end of the box). The line segments below and above the box terminate at the minimum and maximum, unless there are outliers which are identified by hollow bullets and asterisks (asterisks indicate extreme outliers). In those cases, the line segments terminate at the lowest and highest data points falling within the fences.



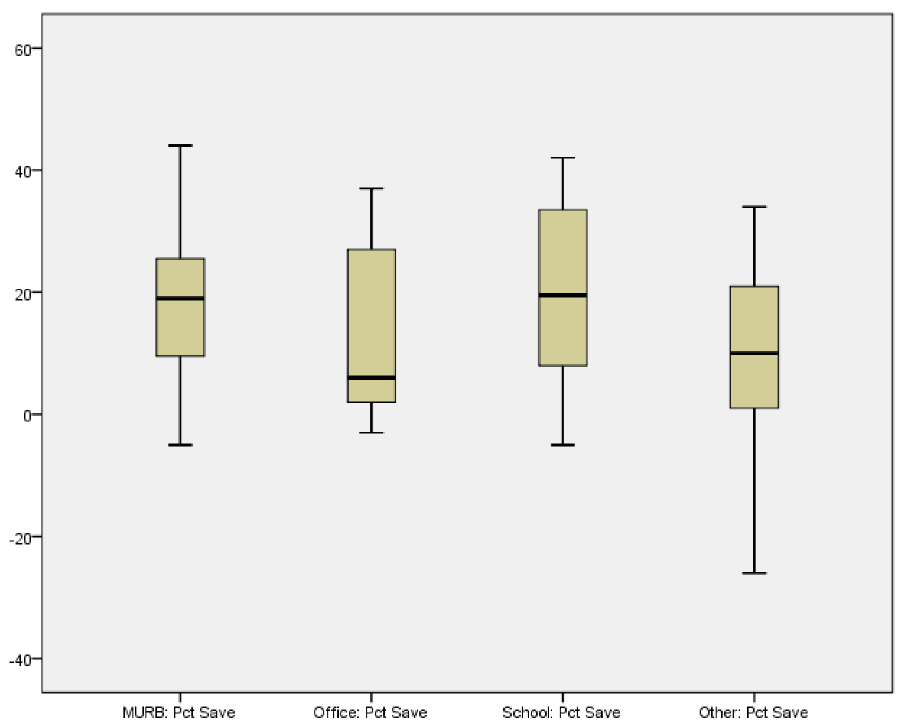
D. Numerical Summaries and Boxplots with Outliers Removed

The following table presents the numerical summaries, for each building type, now with the outliers removed.

	MURB %Saving	*Office %Saving*	*School %Saving*	*Other %Saving*
Sample Size	84	14	12	21
Mean	18.1	12.8	20.3	9.0
Median	19.0	6.0	19.5	10.0
SD	12.0	14.1	16.2	16.1
Minimum	-5	-3	-5	-26
Maximum	44	37	42	34
Lower Quartile	9.2	2.0	6.0	0.5
Upper Quartile	25.8	28.0	33.8	23.0
IQR	16.5	26.0	27.8	22.5

Note that with the outliers removed, the mean and median are much closer to one another and the standard deviations are reduced, and now similar across the four building types.

As in the previous boxplots, the line segments in the interior of the boxes indicate the medians, the lower and upper end of the boxes indicate the quartiles and the line segments stretch to the minimum and the maximum. The wider the box, the greater the dispersion. For all four building types the lower quartile is above zero, indicating that at least 75% of each building type has positive savings.



E. Confidence Intervals

The mean provides a single value estimate of average savings. To incorporate the dispersion in values, 95% confidence intervals (CI) are presented, first based on all data values and then with the four outliers (see Section C) removed. A confidence interval provides a range of plausible or likely values of the true mean, and as such, gives the best summary of the estimated energy saving. Since confidence intervals are based on means and standard deviations, they are also highly sensitive to outliers. Thus the second set of confidence intervals, in bold (with outliers removed), are the sounder estimates.

Building Type	*95% CI (all data)*	*95% CI (outliers removed)*
MURB %Saving	(14.8,20.4)	**(15.5,20.7)**
Office %Saving	(4.7,20.9)	**(4.7,20.9)**
School %Saving	(-1.7,30.3)	**(10.0,30.6)**
Other %Saving	(-21.9,23.9)	**(2.0,15.99)**

The first CI is much narrower than the other three because the sample size for MURBs is much larger. Since the lower limit of each confidence interval in the second set is positive, there is sufficient evidence to conclude that the mean energy saving for each building type is statistically significantly greater than zero. That is, it is fair to conclude that, on average, all four building types experience positive energy saving.

F. Frequency Tables

The distributions of energy savings can also be summarized by categorization, as showed in the table below. A total of 92% of MURBs, 86% of Offices, 77% of Schools and 78% of Others had positive saving. Overall, 87% (118 of 135) of buildings had positive savings; these appear in bold font in the table.

	MURB: % Savings		*Office: % Savings*		*School: % Savings*		*Other: % Savings*	
	Count	*Pct*	*Count*	*Pct*	*Count*	*Pct*	*Count*	*Pct*
Less than 0%	7	8%	2	14%	3	23%	5	23%
0% to 10%	17	**20%**	6	**43%**	1	**8%**	7	**30%**
11% to 20%	25	**29%**	2	**14%**	3	**23%**	4	**17%**
21% to 30%	24	**28%**	1	**7%**	1	**8%**	4	**17%**
Over 30%	12	**14%**	3	**21%**	5	**38%**	3	**13%**
Total	85	100%	14	100%	13	100%	23	100%

G. Conclusion

All four building types show, on average, positive energy savings, with MURBs having an average saving of 18% (CI: 16% to 21%), Offices at 13% (CI: 5% to 21%), Schools at 20% (CI: 10% to 31%) and Others at 9% (2% to 16%). The lower average for Others is likely due to the more heterogeneous make-up of the buildings in this group.

For the total set of buildings across all four types (with the four outliers removed), the mean and median energy saving are both 16%; the standard deviation is 14%. The 95% confidence interval is (14%, 19%).

*** END ***

UPDATE OF ENERGY SAVINGS ANALYSIS FROM FORTISBC EFFICIENT BOILER PROGRAM (EBP)

Project 2011008

Final Report - August 14, 2013

Limits of Liability

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

APPENDICES

1. EXECUTIVE SUMMARY

This report summarizes the results from a historical billing analysis that has been conducted to quantify the savings associated with FortisBC's Efficient Boiler Program (EBP) updated for 2012[1].

In total, 236 sites are included in the study with a majority being Multi-Unit Residential Buildings (MURB), followed by Office Buildings, and Schools. Thirty-seven additional buildings were aggregated into the group “Other” as the sample size for buildings in this category were quite small. The following figure provides a summary of the building types.

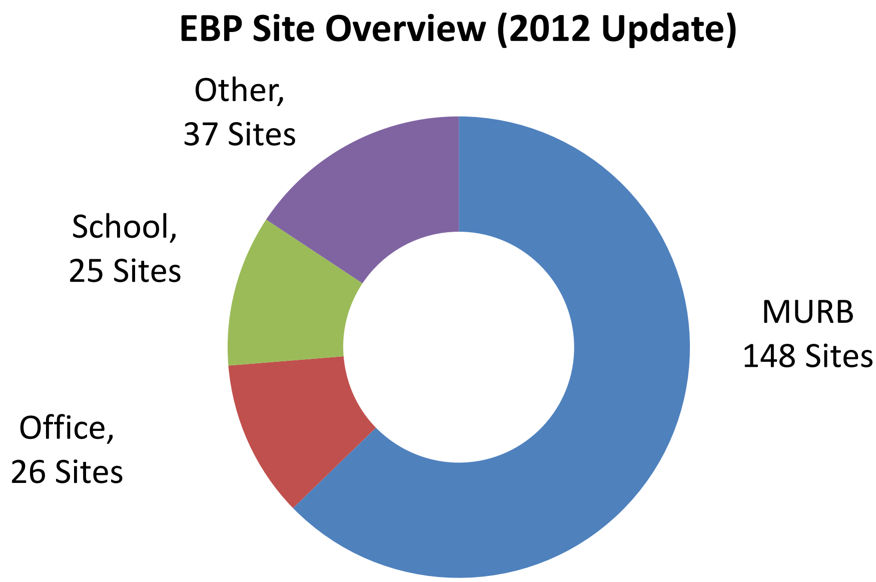


Figure 1: EBP Participant Breakdown by Building Type

The EBP estimates savings of 15% of pre-retrofit energy use and the results from the 2012 update of energy savings confirmed that this continues to be a reasonable savings projection. The 236 program participants which were included in this study show an average savings of 19.4%. Note that the average savings was derived from the performance of the complete post retrofit period for each of the sites.

In 2011/12, the total natural gas savings across all participants included in the study was nearly 200,000 GJ. Extrapolation of these results to all participants of the EBP program up to June 2012 shows savings of approximately 415,000 GJ/year.

[1] Includes data up to June 2012 for most sites

The detailed analysis revealed that savings vary between the four different building types and by retrofitted boiler efficiency as shown in Figure 2.

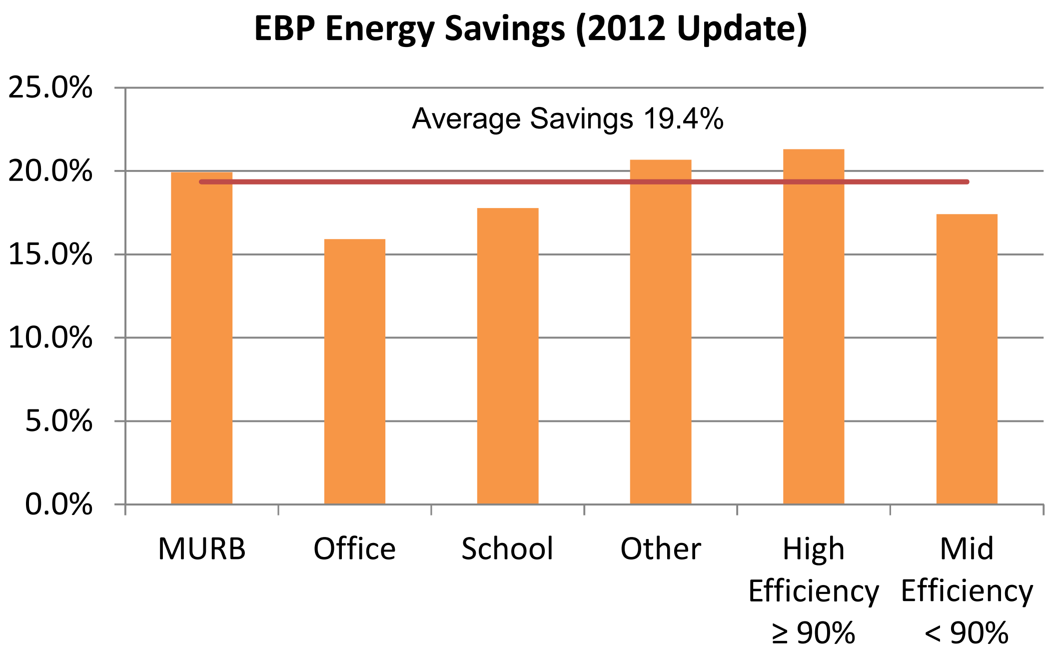


Figure 2: Average Savings By Building Type and By Boiler Efficiency (2012 Update)

Multi-Unit Residential Buildings was the building type with the highest average savings of 20%. School buildings and Offices had slightly lower savings of 18% and 16% respectively. Offices typically have a more complex heating system to allow for heating system redundancy. As a consequence of that the savings results may require more detailed analysis for a correct interpretation of the results.

The boiler efficiency of the retrofitted boiler has an impact on the achieved savings. Sites with high efficiency boilers (efficiency ≥ 90%) achieved savings above the average, whereas sites with mid efficiency boilers showed savings below the average. Similar to the savings analysis carried out by sector, the analysis by efficiency includes the entire post retrofit performance for each of the sites.

2. BACKGROUND

2.1 Introduction

Prism Engineering Ltd. has carried out an analysis to quantify the natural gas savings associated with FortisBC's Efficient Boiler Program (EBP). The evaluation included 236 boiler upgrade projects with the following breakdown:

- a savings analysis update was performed for the 135 participants studied in the 2011 analysis;
- 180 new participants were added to the 2012 analysis;
- 8 participants were identified as statistical outliers and as such excluded from the analysis;
- 71 participants had to be excluded for various reasons, typically insufficient data, as shown in APPENDIX E.

2.2 Scope

The scope of work for this project included the following:

1. evaluate the energy savings resulting from the EBP, including total energy saved in GJ, energy saved in GJ per site (along with the average savings in %), actual vs. projected savings,
2. review multi-year savings trends with analysis of persistency of savings;
3. carry out an analysis of the data segmented by boiler efficiency level such as mid vs. high efficiency;
4. carry out an analysis of the data segmented by building type (MURB, office, school and other);
5. review the boiler sizing (pre and post) to determine the percent oversized for both pre and post retrofit; and
6. where possible, carry out an assessment of the benefit of system changes (piping, pumping) that may have occurred at the same time as the boiler installation.
7. extrapolation of the results to "non-participants" to provide an estimate of the total savings from the program.

2.3 Limitations

The analysis has been carried out based on monthly utility data, information provided by FortisBC, and information collected through a phone survey of responsive participants. Site visits and detailed energy monitoring, both of which would increase the accuracy of the analysis, have not been included in this review.

3. METHODOLOGY

3.1 Overview

Prism used the following methodology to complete the savings analysis for this project:

1. collected and imported data for each natural gas meter premise provided by FortisBC;
2. removed sites with insufficient data from the analysis;
3. identified and selected the twelve month period PRIOR to the retrofit for the baseline;
4. determined the appropriate balance point temperature for each meter (not standard 18°C balance point);
5. set up a baseline model of pre retrofit energy use using single variable linear regression using heating degree days as the independent variable (APPENDIX A**:** for a summary of all models and APPENDIX B for the details of each model);
6. removed participants of the new construction program from the analysis;
7. calculated savings achieved annually post retrofit with weather adjustments: savings were calculated as the baseline adjusted for post retrofit period weather conditions less the post retrofit energy use;
8. removed statistically unusual annual savings figures which were more than two standard deviations from the mean for each group: for example, in the MURB sector, 19 observations (from 8 sites) were outside the limits and could be excluded from the analysis;
9. determined the average savings at each site by averaging the years of available data;
10. determined the average savings by sector and by boiler efficiency level by averaging the results of all sites within each of the grouping.
11. determined if other measures were implemented at the same time and extensiveness of plant upgrade based on a survey to participants and phone follow-up;
12. prepared Cumulative Sum (CUSUM) graphs to review the rate and seasonality of savings
13. evaluated actual vs. projected savings (projections are based on FortisBC program estimate of 15% of pre retrofit energy use);
14. carried out a statistical analysis of the savings results;
15. consolidated and summarized results by sector and boiler efficiency type.

3.2 MT&R Software - Prism Utility Monitoring and Analysis (PUMA)

Prism's PUMA software (www.pumautilitymonitoring.ca) was used for this analysis. Over 10,000 accounts are tracked using this software for Prism clients. FortisBC has been given online access to PUMA reports for this project for a period of six months and can view all accounts, groupings and the energy savings analysis carried out.

3.3 Data Provided by FortisBC

FortisBC has provided the following information:

1. monthly gas consumption with reading date and days with the last reading dates as shown in APPENDIX C.
2. building information (type, sector, heated floor area, physical location);
3. date of boiler installation and data of retrofit boiler (make, model, capacity, efficiency);
4. survey results (provided through a third party).

4. SURVEY

4.1 Survey results

The added participants to the EBP evaluation for this year were asked to complete a 15 question phone based survey conducted by Justason Market Intelligence, a BC-based opinion research firm. Sixty-one (61) participants or about 33% completed the survey. The survey questions are provided in APPENDIX D.

The purpose of the survey was to collect site information on existing mechanical systems and any changes in operating practises to gain a better understanding of the individual savings. The survey results are summarized in Table 1 and show that most customers implement other upgrades at the same time as the boiler replacement.

Table 1: Summary of Survey Results - Boiler Retrofit Scope

Only Boilers	boiler & controls	other plant upgrades
26%	33%	41%

Table 2 shows the breakdown of sites which performed other plant upgrades along with the boiler retrofit. The most common system improvement was an upgrade of the controls system.

Table 2: Summary Survey Results - Other Measures

DDC control	redesign HVAC	Zone isolation	adding of insulation / heat recovery
77%	31%	38%	46%

Table 3 shows the breakdown of sites operating gas consuming equipment on site which is not impacted by the boiler retrofit. These sites might show low savings if the gas consumption by the other gas equipment is significant compared to the overall gas usage of that particular site.

Table 3: Summary Survey Results - Other System Impacting Gas Usage

roof top unit	domestic hot water	kitchen	other
10%	3%	7%	4%

Follow up phone calls were performed for participants where:

- the savings result for the participant's site was significantly different from the averages and classified as outlier, or
- the site's CUSUM showed significant changes in slope indicating inconsistent savings.

The results of the follow up phone calls are included in Section 5.3 with each building type.

5. ANALYSIS

5.1 Overall Annual Energy Savings

For participants in the evaluation, the energy savings were evaluated by comparing the pre and post retrofit data for each site. A regression analysis was done on one year of data immediately prior to the boiler retrofit to establish the energy use model. This period is referred to as the “base period” and its consumption as “baseline”. Energy use after the base period was then compared to the predicted energy consumption using the baseline model for evaluating savings. The calculated savings for participants over the last four years is shown in the following figure:

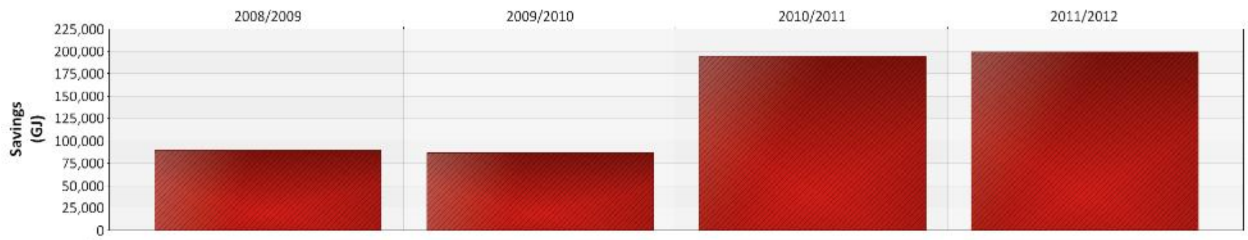


Figure 3: Four Year Summary of Energy Savings

In each of the last two years, the total saving for all studied sites was nearly 200,000 GJ.

5.2 Overall Energy Savings by Site

While some sites only have one year of post retrofit performance, others can have up to five years. All available post retrofit data for all of the sites was used for the 2012 update. Details of the results are provided in Table 4.

Table 4: Overall Project Summary (2012 Update)

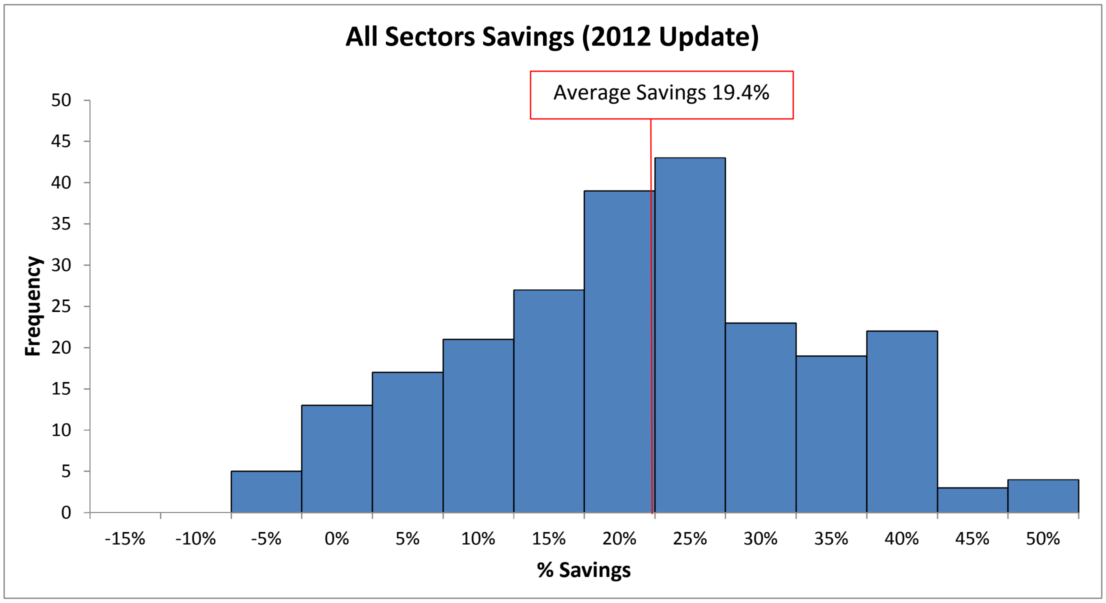
Number of Sites	236
Average Savings	19.4%
Standard deviation	12%
95% Confidence interval	17.8%, 20.9%

Note that statistic parameters such as the mean or average, standard deviation and confidence interval are highly sensitive to outliers. Therefore, outliers were determined and excluded prior to calculating any statistical parameter.

Based on the above, one can be 95% confident that the overall average savings of the sites falls between 17.8% and 20.9%.

Figure 4 shows a histogram of the savings of all sites demonstrating the following:

- a wide spread of annual savings have been determined ranging from 47% to -10%. Note that the statistical outliers were excluded prior to plotting this histogram; and
- the histogram suggests a symmetrical distribution with a mean at around 20%.



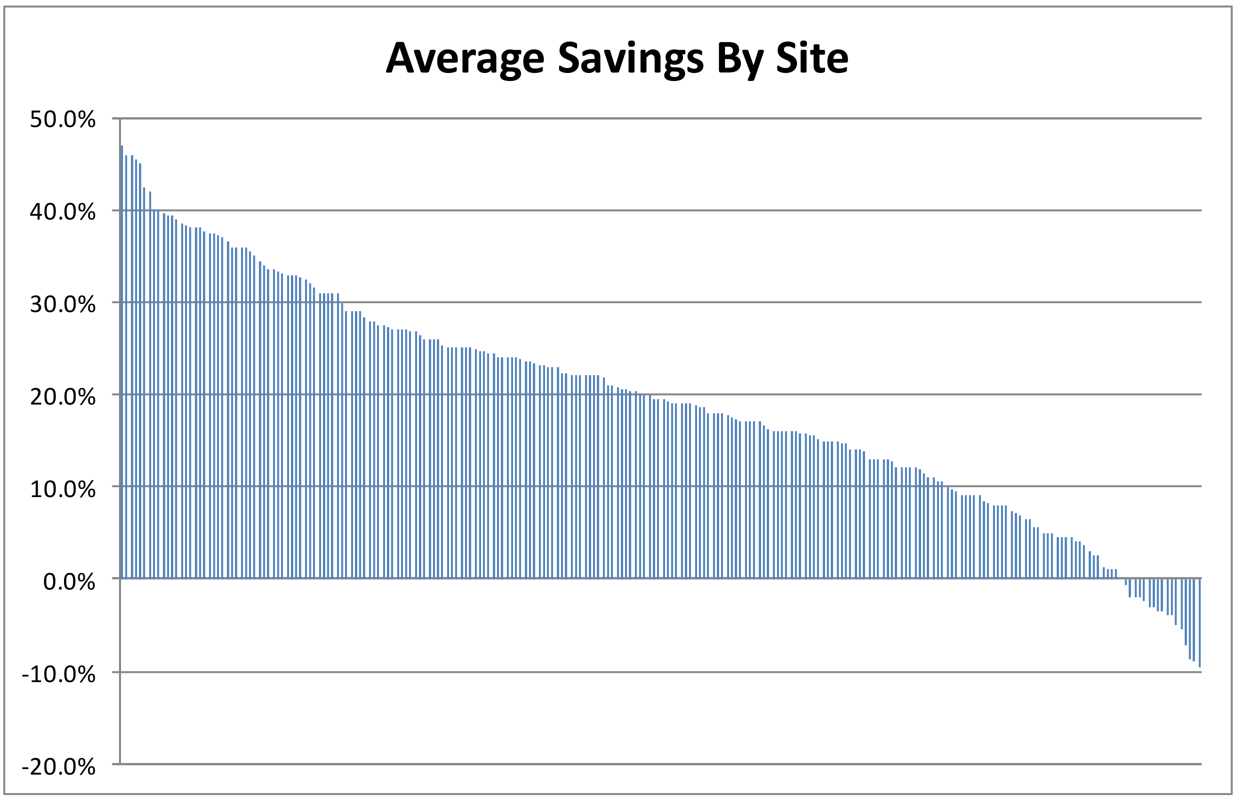


Figure 4: Histogram All Sites % Savings (Bin View and Site View)

Table 5 shows a breakdown of the savings results by building type utilizing all available post retrofit data for each of the sites. The details of the savings result by building type can be found in the respective sections of the report.

Table 5: Project Summary Energy Analysis By Sector

	MURB	Office	School	Other
Total Number of Sites	151	29	26	38
Number of Sites Included	148	26	25	37
Site Excluded	3	3	1	1
Average Savings	19.9%	15.9%	17.8%	20.7%

5.3 Cumulative Sum of Energy Savings

CUSUM (Cumulative Sum) is an analysis technique employed to visualize and quantify changes in energy usage and the trends in savings performance. The CUSUM is a summation or "running total" of the savings which are calculated as difference in energy use between baseline and actual.

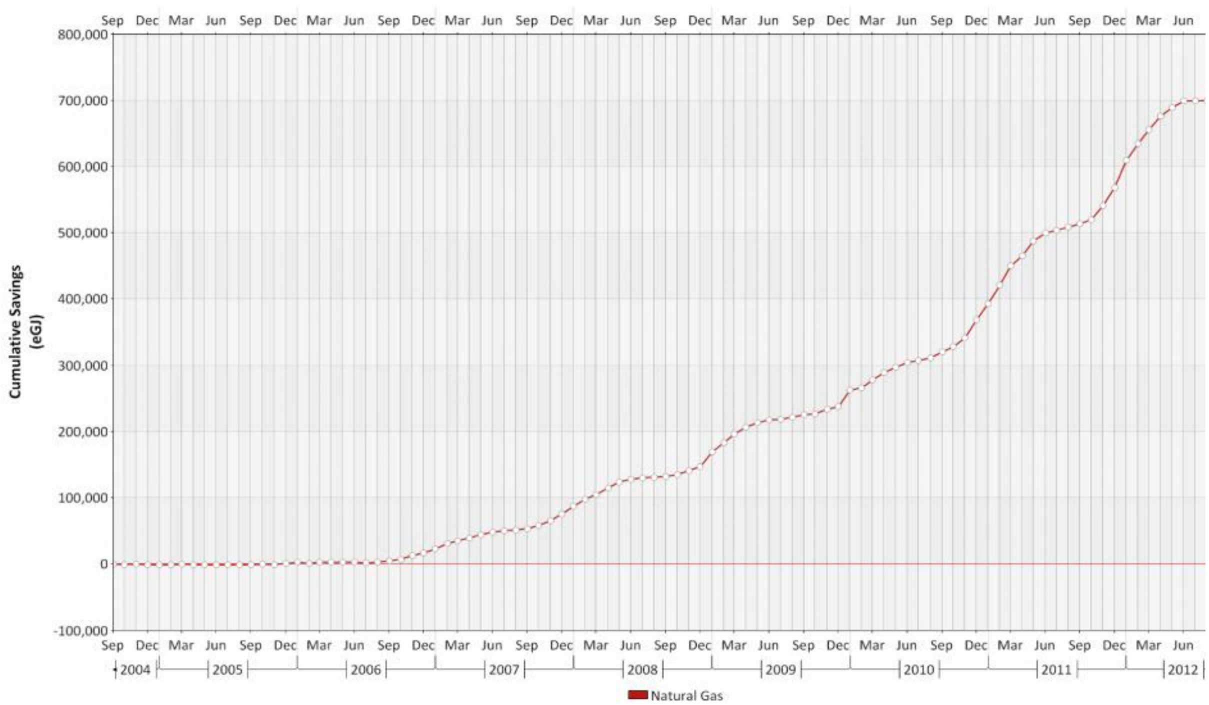


Figure 5: Combined CUSUM for All Studied Sites

The CUSUM over the entire project (including all studied applicants), as shown in Figure 5 and in APPENDIX G, demonstrates that significant savings were achieved from 2006 to 2012 from the EBP. Savings were achieved during heating and non heating periods with a greater rate of savings during the heating seasons (as shown by the steeper incline in the CUSUM). The CUSUMs for each site are shown in APPENDIX H (available as a separate attachment due to file size) and available online with PUMA access.

Cumulatively, nearly 700,000 GJ natural gas savings was achieved across the entire program by June 2012 for the sites included in the study. The slope of the combined CUSUM is the highest in the heating seasons of 2010/11 and 2011/12 where the rate of savings are the greatest. Note that the CUSUM graph does not exclude years removed due to unusual savings observations.

5.4 Energy Analysis by Building Type

To identify if energy savings was dependent on the type of building use, an energy use analysis by building type has been carried out. Groupings were established for Multi Unit Residential Buildings (MURB), Office and School Buildings. The remaining building types are very diverse and the sample sizes for the remaining building types would have been too small for any subgrouping. Therefore, we have aggregated the remaining sites into a combined group called "Other". The following sections discuss the results of each of these sectors and the detailed results can be found in APPENDIX J and APPENDIX K.

Multi Unit Residential Buildings

Table 6: MURB Summary Energy Analysis (2012 Update)

Number of Sites Analyzed	151
Median Savings (all years, all sites, including outliers)	20.6%
Mean Savings (all years, all sites, including outliers)	19.5%
Two Standard deviations	27.8%
Acceptable Range	-8.3%, 47.2%
# sites excluded as all values outside acceptable range	3
Number of Sites Included	148
Average Savings Per Site (excluding outliers)	**19.9%**

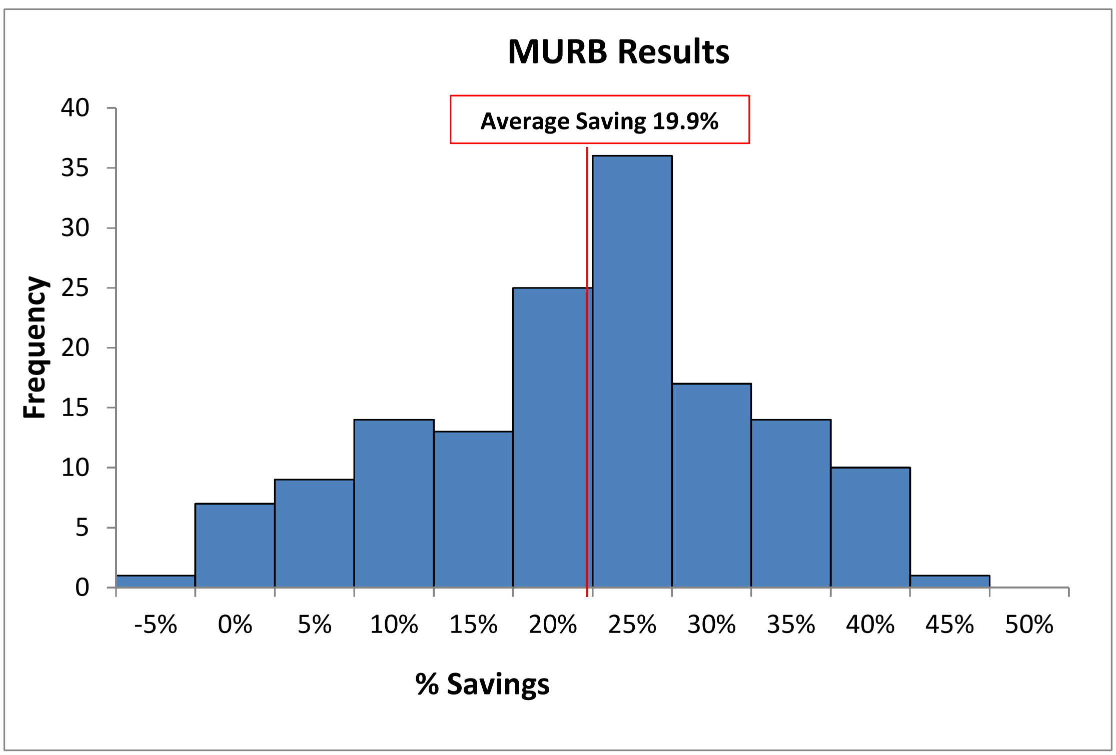


Figure 6: Histogram MURB % Savings (2012 Update)

The bulk part of the MURB sites fall within the category of 5% to 35% savings and

- 26 sites showed savings over 30%;
- 30 sites showed savings below 10%.

From the 11 sites with no or negative savings only one site A11-0462 with -2% savings responded to the survey. The heating plant for which the boiler retrofit was carried out is for heating purposes only and a control upgrade was implemented along with the boiler retrofit. The Load Factor of 0.53 (determined through the boiler sizing analysis) suggest that the retrofitted boiler could be oversized resulting into short cycling which could explain the poor performance of the retrofit.

Follow up phone call were initiated for sites where observed savings were at either extremes of the savings profile. The following summarizes the feedback received and actions taken:

- Site 05-0054: Savings of 70% were calculated in 2009/10 while other years were consistently between 25% and 29%. We were unable to make contact with this customer but expect that there was an erroneous reading for the 3/17/2010 reading of 182 days based on the billing profile. Savings from this one year was determined as an outlier and removed in the statistical analysis of the data.
- Site 05-0043: Savings of 60% were calculated in 2011/12 while other years were consistently between 3% and 23%. By contacting the customer, we were able to determine that the savings were due to fuel switching to an electric boiler that was operating more frequently than it was designed to. Savings from this one year was determined as an outlier and removed in the statistical analysis of the data.
- Site 05-0046: An increase in gas use of 16% was calculated in 2011/12 and other years had increases between 0% and 4%. After contacting the customer, we were not able to conclusively identify the reason for the higher use. The increase may be related to higher usage as the previous system had some capacity issues and the tenants are now more family oriented. Savings from this one year was determined as an outlier and removed in the statistical analysis of the data.
- Site 05-0041: An increase in gas use of 16% was calculated in 2011/12 and other years had increases of 10% (2010/11) and savings between 3% and 5%. After 3 attempts, we were unable to make contact with this customer. Savings from two years were determined as outliers and removed in the statistical analysis of the data.
- Site 10-0302: An increase in gas use of 19% was calculated in 2011/12, the only full year post retrofit. After contacting the customer, we were not able to conclusively identify the reason for the higher use. The customer was amenable to a follow up site visit. Savings from this one year was determined as an outlier and removed in the statistical analysis of the data.
- Site 10-0288: An increase in gas use of 27% was calculated in 2011/12, the only full year post retrofit. After contacting the customer and the installer (who sent a technician on site to follow up), we were not able to conclusively identify the reason for the higher use. The customer was amenable to a follow up site visit. Savings from this one year was determined as an outlier and removed in the statistical analysis of the data.

Offices Buildings

Number of Sites Analyzed	29
Median Savings (all years, all sites, including outliers)	12.0%
Mean Savings (all years, all sites, including outliers)	14.3%
Two Standard deviations	39.5%
Acceptable Range	-25.2%, 53.7%
# sites excluded as all values outside acceptable range	3
Number of Sites Included	26
Average Savings Per Site (excluding outliers)	**15.9%**

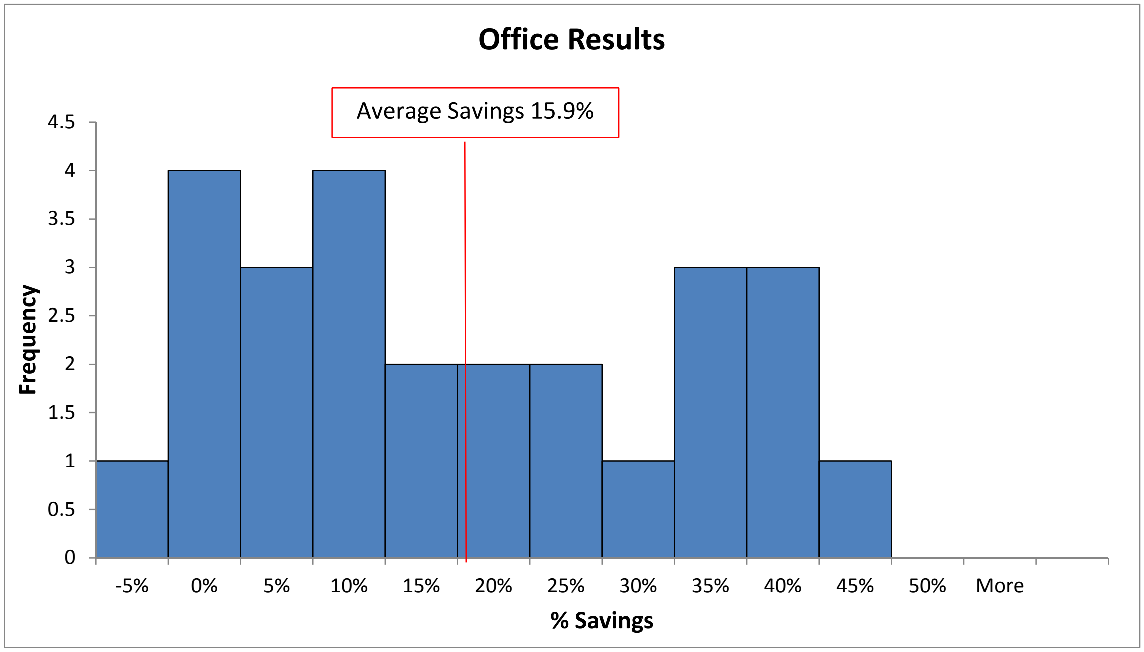


Figure 7: Histogram Office % Savings (2012 Update)

The office buildings showed a wide spread of achieved savings ranging from 45% to -5.5%. The bulk part of the sites achieved savings between 0% and 25% and

- 7 sites showed annual savings higher than 30%
- 7 sites showed savings below 5%.

School Buildings

Table 7: School Summary Energy Analysis (2012 Update)

Number of Sites Analyzed	26
Median Savings (all years, all sites, including outliers)	17.0%
Mean Savings (all years, all sites, including outliers)	16.7%

Two Standard deviations	42.6%
Acceptable Range	-25.9%, 59.4%
# sites excluded as all values outside acceptable range	1
Number of Sites Included	25
Average Savings Per Site (excluding outliers)	**17.8%**

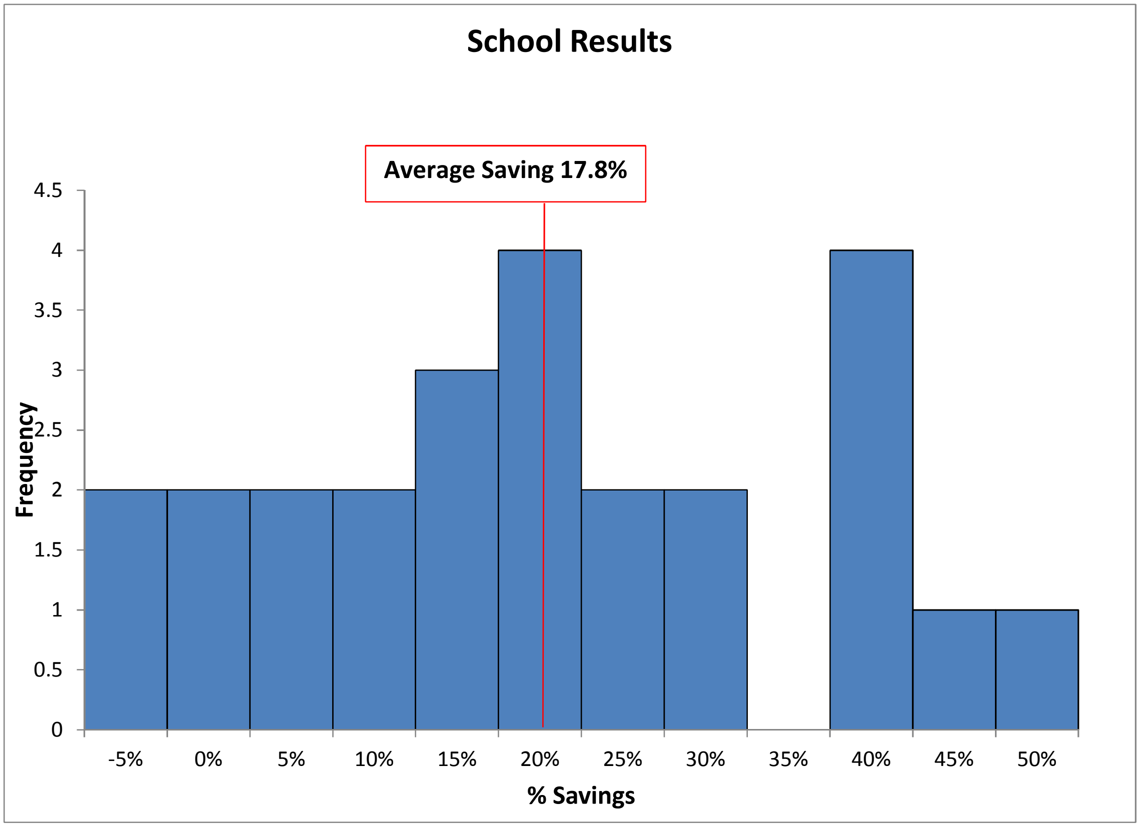


Figure 8: Histogram School % Savings (2012 Update)

The majority of the sites achieved savings between 10% and 30% and a review of the savings of the individual sites revealed the following:

- four sites show negative savings; and
- the six sites with annual savings significantly above average and > 30% consistently show above average for each year over a four year period. Only one site of these sites responded to the survey. Participant A10-0256 provided the information that the retrofit was carried out without any changes such as controls upgrades.

Follow up phone call were initiated for sites where observed savings were at either extremes of the savings profile. The following summarizes the feedback received and actions taken:

- Site 05-0084: An increase in gas use of 50% was calculated in 2011/12 and other years had savings between 11% and 31%. After contacting the customer, we were not able to conclusively identify the reason for the higher use. The increase may be related to a failed boiler (cracked heat exchanger) and lack of maintenance. Currently the school is vacant and no follow up is recommended. Savings from this one year was determined as an outlier and removed in the statistical analysis of the data.

- Site 10-0336: Increases in gas use of 58% and 60% were calculated in the two years post retrofit. After contacting the customer, we were not able to conclusively identify the reason for the higher use. Other projects, including the installation of a solar wall, occurred concurrently with the boiler retrofit. The customer was amenable to a follow up site visit. Savings from this site year were determined outliers and removed in the statistical analysis of the data.

Other Buildings

This "Other" category aggregates the results of the following building types: Other Housing, Care Homes, Churches, Culture Centres, Fire halls, Recreational Buildings, Hospitals, Hotels, Greenhouses, and Shopping Centres.

Table 8: Other Summary Energy Analysis (2012 Update)

Number of Sites Analyzed	38
Median Savings (all years, all sites, including outliers)	17.0%
Mean Savings (all years, all sites, including outliers)	17.7%
Two Standard deviations	31.9%
Acceptable Range	-14.2%, 49.7%
# sites excluded as all values outside acceptable range	1
Number of Sites Included	37
Average Savings Per Site (excluding outliers)	**20.7%**

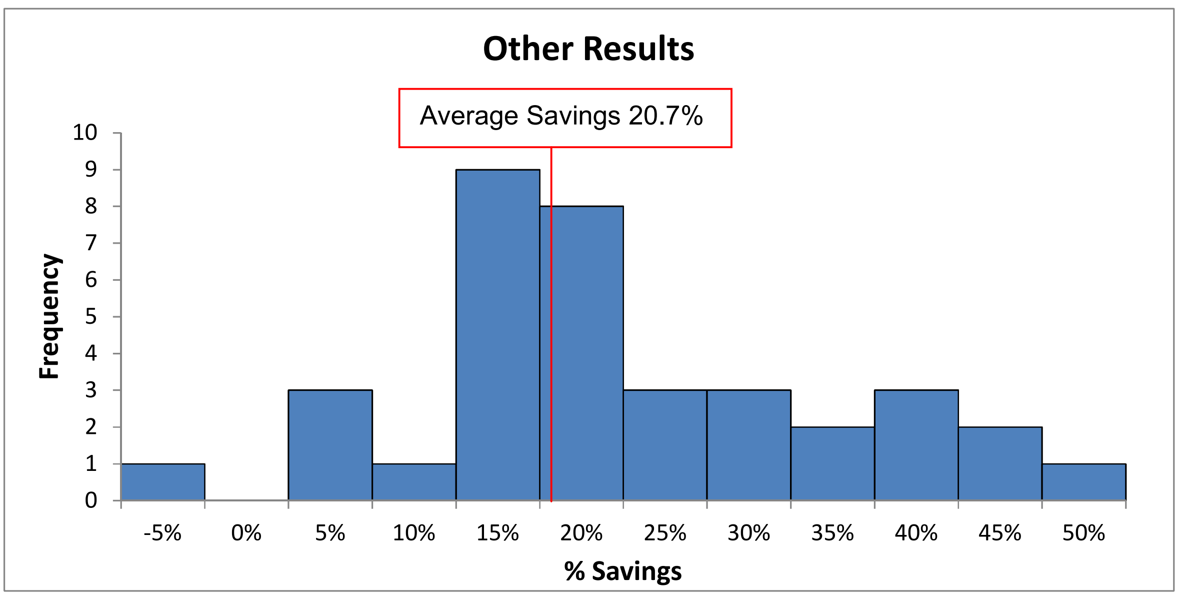


Figure 9: Histogram Other % Savings (2012 Update)

The majority of the sites achieved savings between 10% and 30% and three sites showed savings under 5% while nine sites had savings significantly above average (>30%).

Only one site (A05-0091) with negative savings responded to the survey providing the information that the boiler installation was carried out as a new construction project. The CUSUM shows a significant trend change starting February 2012 which suggest a change in load due to the new construction. As a result, new construction projects were removed from the analysis.

Follow up phone call were initiated for sites where observed savings were at either extremes of the savings profile. The following summarizes the feedback received and actions taken:

- Site A10-0334: Savings of 78% of 2011/12 were a result of a malfunctioning metering device at the site (the meter's battery needed to be changed so the actual consumption for the months reviewed were not captured). This site was excluded from the participants study.
- Site 10-0311: An increase in gas use of 30% was calculated in 2011/12, the only full year post retrofit. After contacting the customer, we were not able to conclusively identify the reason for the higher use. The customer was amenable to a follow up site visit. Savings from this one year was determined as an outlier and removed in the statistical analysis of the data.
- Site 05-0163: Increases in gas use between 7% and 40% were calculated in the four years post retrofit. After contacting the customer, we were not able to conclusively identify the reason for the higher use. We expect that the increase are due to major expansions at this large shopping mall and may not be related to the boiler performance. As a result, this site was excluded from the participants study.
- Site 05-0169: Increases in gas use between 19% and 34% were calculated in the four years post retrofit. After contacting the customer, we were able to determine that the increases were due to major expansion at this greenhouse (doubling in size) and not related to the boiler performance. As a result, this site was excluded from the participants study.
- Site 05-0206: Increases in gas use between 1% and 46% were calculated in the two years post retrofit. After contacting the customer, we were able to determine that the increases were most likely due to major changes in operations (increase in number of events and weddings) at this community centre and likely not related to the boiler performance. This was evident in a major change in base load, not weather sensitive load due to what is expected to be kitchen use. As a result, this site was excluded from the participants study.

5.5 Energy Analysis by Boiler Efficiency Levels

Analysis of the energy data segmented by boiler efficiency level was performed to identify the average savings by boiler efficiency. The annual savings for 2011/12 for all participants from Group 1 and Group 2 were included in this analysis. For a small number of participants the boiler efficiency was not provided and these sites were excluded in this analysis. The details of this analysis are provided in APPENDIX I.

Table 9: Energy Analysis by Boiler Efficiency Category

	High efficiency boiler (≥ 90%)	**Mid efficiency boiler (< 90%)**	**All studied sites excluding outliers**
Sample size	89(*)	109(*)	239(**)
Average Saving	23%	17%	19%

(*) outliers and participants without boiler efficiency data excluded

(**) outliers excluded

As shown in the Table 10 and Figure 1 it can be concluded that the sites that installed high efficiency boilers achieved above average savings and higher savings than sites that installed mid efficiency boilers. The result of this analysis suggests that sites with mid efficiency boilers achieved savings slightly below the overall average of all studied sites.

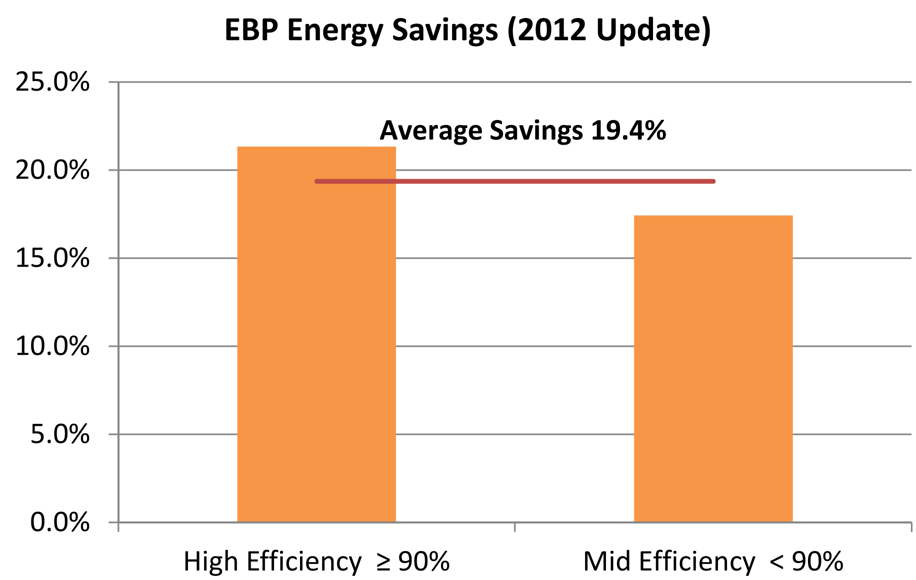


Figure 10: Average Savings By Boiler Efficiency (2012 Update)

5.6 Boiler Sizing Review

A review of boiler sizing was performed for post retrofit conditions using the installed boiler capacity for the retrofitted boiler. A pre retrofit analysis was not performed due to lack of data of the installed capacity prior to the retrofit. The goal for this analysis was to estimate the oversized percentage of the new boilers.

Methodology

1. The baseline period was chosen as the post retrofit condition. 2011/12 was set as baseline period for the analysis as the retrofit activities were completed for all studied sites prior to May 2011.
2. We determined the design heating load to ensure adequate sizing of the boiler based on an estimated occupancy load as shown in the table below.

Sector	hr per day occupied	days per week occupied	% occupied
Residential	24	7	100
Health Care	24	7	100
Education	9	5	27
Commercial	10	5	30
Retail	12	7	50
Government	10	5	30

3. A total of 84 participants from Group 2 were considered for this analysis.
4. We determined the load factor for each site. The load factor represents the design heating load to the installed boiler capacity.

The results are summarized in the following table:

Table 10: Boiler Sizing Results

Load Factor (ratio of design load to installed capacity)	Number of Sites
<0.5	21
>0.5 to 0.7	21
>0.7 to 1.3	31
>1.3	11

A load factor of < 0.5 indicates that the installed boiler capacity is much higher than (more than twice) the design heating load. 10 out of 21 sites with potentially oversized boilers were installed in residential buildings.

21 sites fall within the classification > 0.5 to 0.7. To determine if the installed boiler capacity is reasonable an analysis on a case by case basis would have to be performed. For instance some sites operate a boiler plant with more than one boiler to guarantee operation in case one of the boilers fails. The installed boiler capacity would have to be assessed based on requirements on the boiler plant and the site operation requirements.

A significant portion of the sites fall within the range > 0.7 and 1.3 which would suggest that the installed boiler capacity is reasonable. This judgement would have to be verified on a case by case basis for the same reasons as discussed earlier.

Sites which fall under the last category of > 1.3 indicate that, most probably, other gas consuming equipment are operating on site.

5.7 Overall Program Savings All Participants

FortisBC is interested in the annual rate of savings for the entire program in energy savings (GJ) per year. As of March 2013, the Efficient Boiler Program included a total of approximately 540 participants. To extrapolate the results of this study to the overall program, an analysis was conducted based on the energy savings in 2011/12 of participants in the study. The following methodology was applied:

- Rate of verified savings (GJ/MBH/year) was calculated from the participants based on their 2012 update savings results. This was done for each of the sectors; and
- Rate of verified savings was applied against retrofit boiler capacity of participants not included in study. Again, this was done for each of the sectors; and
- If the category was not identified (unknown), the savings applied was based on the overall program savings from all categories.

We also investigated the impact of regional heating degree days on the GJ per MBH but we did not find this relevant to the results. This may be due to the larger boiler plants in colder regions (thus similar GJ/MBH) as well as limited data from higher HDD regions.

The results shown in table below provide a breakdown of the overall program savings rate.

Table 11: Overall Program Rate of Savings (GJ/year) (2012 Update)

Rate of Savings (GJ/year)		MURB	Office	School	Other	unknown	Total	# of sites
EBP Study Participants	(2011/12 results)	120,868	17,323	12,382	45,209	0	**195,781**	227
Participants not included in EBP Study (retrofit only)	estimated	44,476	12,097	14,448	45,115	102,750	**218,887**	267
Total		**165,344**	**29,420**	**26,830**	**90,323**	**102,750**	**414,668**	494

The category “Participants not included in EBP study” includes 56 participants have been approved for the Efficient Boiler Program but had not yet completed the boiler retrofit (as of March 2013).

Not included in the overall program savings results are the following:

- Thirty-Three (33) EBP participants due to:
  - sites where 2011/12 data was determined to be outliers;
  - sites excluded from participants group due to major expansion or similar scenario due to follow up phone calls;
  - missing boiler ratings which prevented extrapoloation.
- New construction projects.

6. RECOMMENDATIONS

6.1 Measurement and Verification

M&V of the savings from boiler retrofits is difficult to carry out using utility bill analysis in the following scenarios

- Other energy savings measures implemented at the same time (resulting in claimed savings from the boiler retrofit in percent that are OVER estimated);
- The utility bill may include natural gas consumption from other loads that are not impacted by the boiler retrofit (resulting in claimed savings from the boiler retrofit in percent that are UNDER estimated).

It is recommended to establish a building questionnaire similar to the questions as asked during the survey. This would allow collecting site specific information such as operation profile, basic information of installed mechanical system and other gas consuming equipment on site.

This questionnaire should be a mandatory document which has to be filled out by the applicant along with the application for the Efficient Boiler Program. This guarantees 100% response rate and provides a broader database for correlating M&V results with actual site conditions. Furthermore the mandatory questionnaire would help in saving the expenditure for post retrofit survey.

A more accurate M&V protocol that would improve the accuracy of the results would be to submeter the boiler plant being retrofitted post installation.

6.2 Tracking Ongoing Savings

Now that all account baselines and grouping have been set up in PUMA and made available online, FortisBC may wish to continue to use MT&R with PUMA as a part of the EBP to track and verify savings on an ongoing basis. Sites with changes in performance can be follow up on.

6.3 Follow up on Non Performance

The outlier analysis identified 18 sites that have savings outside of the expected range of results. Further follow up with these sites would increase the confidence in the results.

In addition, the individual CUSUM results show sites that were included in the savings analysis but where further follow up with low savings (under 10%) may yield more information that could be used for the analysis.

APPENDIX A: Base Period Summary

Site Name	Account Number	Model Name	Start	End	Base Load	R2	CV(RMSE)	Offsets	Weights	Heating Slope	Heating Balance Point
A05-0003	1178691	Heating Analysis	2004-09-01	2005-08-31	5.09	.98	7%	No	No	1.12	18.00
A05-0004	1178545	Heating Analysis	2004-08-31	2005-08-31	2.94	.98	6%	No	Yes	.97	18.00
A05-0005	1178546	Heating Analysis	2004-09-01	2005-08-31	2.26	.97	10%	No	No	.89	18.00
A05-0006	1179373	Heating Analysis	2004-08-01	2005-07-31	11.82	.97	8%	No	No	2.59	18.00
A05-0007	168567	Heating Analysis	2005-10-04	2006-09-26	2.09	.99	6%	No	No	.79	15.50
A05-0008	1850990	Heating Analysis	2004-10-29	2005-10-27	7.26	.97	7%	No	No	1.28	16.50
A05-0009	367968	Heating Analysis	2004-11-30	2005-11-25	-.08	.90	23%	No	No	.34	15.00
A05-0010	1178913	Heating Analysis	2004-08-21	2005-08-31	42.44	.98	7%	No	No	9.92	17.50
A05-0011	1179742	Heating Analysis	2006-03-01	2007-03-15	6.72	.99	3%	No	No	2.12	14.00
A05-0012	500068	Heating Analysis	2004-09-15	2005-09-13	.13	.98	10%	No	No	.49	17.50
A05-0015	686646	Heating Analysis	2007-08-18	2008-08-19	1.14	.98	6%	No	No	.19	16.00
A05-0017	772342	Heating Analysis	2004-09-01	2005-08-31	.10	.95	18%	No	No	.73	16.00
A05-0019	623020	Heating Analysis	2004-09-28	2005-09-26	1.60	.95	18%	No	Yes	1.02	16.50
A05-0020	1016484	Heating Analysis	2004-09-16	2005-09-13	.78	.96	14%	No	No	.86	17.50
A05-0021	498623	Heating Analysis	2004-10-15	2005-10-13	1.18	.98	0%	No	No	.47	16.00
A05-0022	1696560	Heating Analysis	2005-01-01	2005-12-31	2.42	.98	8%	No	No	.76	17.00
A05-0023	372654	Heating Analysis	2004-09-25	2005-09-23	.13	.96	16%	No	No	.11	15.00
A05-0024	1234106	Non-Weather Related	2005-11-01	2006-10-31	81.39	.00	123%	Yes	No		
A05-0026	639998	Heating Analysis	2005-11-17	2006-11-16	.66	.86	19%	No	Yes	.23	17.50
A05-0027	646949	Heating Analysis	2004-11-06	2005-11-04	1.37	.95	0%	No	No	.77	16.50
A05-0028	565844	Non-Weather Related	2005-06-29	2006-06-27	10.10	.00	0%	Yes	No		
A05-0029	1025771	Heating Analysis	2005-10-14	2006-10-13	1.48	.98	10%	No	No	.96	13.00
A05-0030	522035	Heating Analysis	2005-06-23	2006-06-22	1.19	.97	24%	No	No	.60	12.50
A05-0031	481313	Heating Analysis	2004-12-10	2005-12-07	2.51	.98	5%	No	No	.28	18.00
A05-0032	1179455	Heating Analysis	2005-10-01	2006-09-30	22.13	.96	9%	No	No	3.70	15.50
A05-0033	1696560	Heating Analysis	2005-02-01	2006-01-31	6.26	.95	9%	No	No	.80	18.00
A05-0034	847135	Heating Analysis	2005-10-06	2006-10-05	.14	.99	0%	No	No	.04	13.50
A05-0035	151124	Heating Analysis	2005-12-07	2006-12-05	1.67	.90	18%	No	No	.25	17.00
A05-0037	1307154	Heating Analysis	2005-08-24	2006-07-24	2.99	.90	0%	No	No	.51	14.50
A05-0040	1639618	Heating Analysis	2005-03-01	2006-02-28	31.78	.96	6%	No	No	2.80	17.00
A05-0041	623991	Heating Analysis	2005-03-31	2006-03-29	.98	.88	19%	No	No	.33	18.00
A05-0042	623990	Heating Analysis	2005-03-31	2006-03-29	1.32	.92	15%	No	No	.32	18.00
A05-0043	1696560	Heating Analysis	2006-05-01	2007-04-30	8.24	.95	11%	No	No	1.87	17.50
A05-0044	622935	Heating Analysis	2005-08-13	2006-08-14	.09	.99	10%	No	No	.88	13.50
A05-0045	1178526	Heating Analysis	2005-08-01	2006-07-31	7.24	.97	9%	No	No	2.43	17.50
A05-0046	1179092	Heating Analysis	2006-02-01	2007-01-31	8.02	.99	5%	No	No	2.04	16.00
A05-0048	622935	Heating Analysis	2005-09-15	2006-09-14	.00	.99	0%	No	No	1.16	13.50
A05-0050	498499	Heating Analysis	2006-05-11	2007-05-09	2.69	.96	24%	No	No	.62	13.50
A05-0051	1247800	Heating Analysis	2005-09-14	2006-09-13	2.92	.98	10%	No	No	1.68	17.50
A05-0052	1317022	Heating Analysis	2005-07-29	2006-07-28	2.81	.95	0%	No	No	1.14	17.50
A05-0053	623537	Heating Analysis	2005-08-27	2006-08-29	2.01	.97	0%	No	No	1.00	20.00
A05-0054	803143	Heating Analysis	2004-06-01	2006-06-15	6.52	1.00	3%	No	No	1.51	16.50
A05-0055	803143	Heating Analysis	2005-06-16	2006-06-15	7.03	.97	0%	No	No	1.57	16.00
A05-0056	803143	Heating Analysis	2005-06-16	2006-06-15	1.79	.98	0%	No	No	.37	16.50
A05-0057	803143	Heating Analysis	2005-06-16	2006-06-15	1.72	.97	0%	No	No	.41	15.50
A05-0058	803143	Heating Analysis	2005-06-16	2006-06-15	4.10	.99	0%	No	No	.69	13.00
A05-0059	803143	Heating Analysis	2005-06-16	2006-06-15	1.73	.98	8%	No	No	.76	18.00

Site Name	Account Number	Model Name	Start	End	Base Load	R2	CV(RMSE)	Offsets	Weights	Heating Slope	Heating Balance Point
A05-0060	803143	Heating Analysis	2005-06-16	2006-06-15	2.18	.98	0%	No	No	.67	17.00
A05-0061	803143	Heating Analysis	2005-06-16	2006-06-15	2.83	.98	0%	No	No	.69	18.00
A05-0062	1196428	Heating Analysis	2005-10-01	2006-09-30	.64	.98	0%	No	No	4.56	15.50
A05-0065	509483	Heating Analysis	2005-10-28	2006-10-30	.58	.98	12%	No	No	2.32	15.50
A05-0066	1178446	Heating Analysis	2005-11-04	2006-11-03	2.38	.95	15%	No	No	.64	16.00
A05-0068	1298386	Heating Analysis	2005-08-30	2006-08-31	6.78	.71	0%	No	No	.89	16.00
A05-0069	1178545	Heating Analysis	2005-09-01	2006-08-31	7.48	.98	8%	No	No	2.27	18.00
A05-0070	1178545	Heating Analysis	2005-09-01	2006-08-31	3.71	.99	7%	No	No	2.19	18.00
A05-0072	497887	Heating Analysis	2005-10-01	2006-09-30	1.80	.99	7%	No	No	.99	17.00
A05-0077	358232	Heating Analysis	2005-11-15	2006-11-14	.15	.99	12%	No	No	.52	14.00
A05-0079	772955	Heating Analysis	2005-07-05	2006-06-30	10.33	.97	5%	No	No	.95	14.50
A05-0080	1121989	Heating Analysis	2005-08-26	2006-08-31	2.81	.85	22%	No	No	.91	16.50
A05-0081	1696560	Heating Analysis	2005-09-01	2006-08-31	36.53	.98	6%	No	No	7.67	18.00
A05-0082	1696560	Heating Analysis	2005-10-01	2006-09-30	11.33	.96	9%	No	No	1.88	17.00
A05-0084	772342	Heating Analysis	2005-09-16	2006-09-15	.05	.96	14%	No	No	.40	15.00
A05-0085	647014	Heating Analysis	2005-07-08	2006-06-23	1.39	.98	8%	No	No	.93	18.00
A05-0086	318777	Heating Analysis	2006-05-17	2007-05-17	3.73	1.00	4%	No	No	3.39	12.00
A05-0087	1179883	Heating Analysis	2006-01-01	2006-12-31	7.08	.81	22%	No	No	1.37	16.00
A05-0089	1701887	Heating Analysis	2005-11-19	2006-11-20	.00	.97	19%	No	No	.58	11.50
A05-0093	623591	Heating Analysis	2005-10-28	2006-10-27	4.03	.87	15%	No	No	1.05	17.50
A05-0094	1196426	Heating Analysis	2005-09-01	2006-08-31	.86	.95	13%	No	No	.59	18.00
A05-0095	267929	Heating Analysis	2006-07-05	2007-07-05	1.27	.93	19%	No	No	.84	18.50
A05-0096	168568	Heating Analysis	2005-08-04	2006-08-02	.08	.99	8%	No	No	.53	12.00
A05-0098	1179918	Heating Analysis	2005-12-01	2006-11-30	3.51	.91	21%	No	No	2.75	16.00
A05-0099	1179439	Heating Analysis	2005-10-01	2006-09-30	4.16	.98	10%	No	No	2.62	17.50
A05-0100	950726	Heating Analysis	2005-12-09	2006-12-06	1.78	.84	29%	No	No	.42	16.50
A05-0101	1891403	Heating Analysis	2005-11-29	2006-11-27	.31	.98	10%	No	No	1.77	13.50
A05-0102	1179472	Heating Analysis	2006-06-01	2007-05-31	40.54	.97	9%	No	No	11.70	15.50
A05-0103	647243	Heating Analysis	2006-05-04	2007-05-03	2.81	.90	11%	No	No	.36	17.00
A05-0104	1696560	Heating Analysis	2006-04-01	2007-03-31	3.07	.90	13%	No	No	.47	17.50
A05-0105	647243	Heating Analysis	2006-03-03	2007-03-01	3.69	.92	13%	No	No	.33	20.00
A05-0106	1696560	Heating Analysis	2006-04-01	2007-03-31	5.16	.97	5%	No	No	.46	17.50
A05-0109	656898	Heating Analysis	2005-10-08	2006-10-10	3.00	.97	9%	No	No	.63	17.00
A05-0110	1300786	Heating Analysis	2005-10-01	2006-09-30	1.43	.98	11%	No	No	1.34	16.00
A05-0112	1178736	Heating Analysis	2005-10-01	2006-09-30	3.29	.99	6%	No	No	1.70	17.50
A05-0114	1696560	Heating Analysis	2006-01-01	2006-12-31	15.88	.97	6%	No	No	2.40	16.00
A05-0115	1696560	Heating Analysis	2006-04-01	2007-03-31	10.43	.84	13%	No	No	.89	17.50
A05-0116	1240604	Heating Analysis	2006-04-08	2007-04-10	2.22	.91	17%	No	No	.70	17.00
A05-0119	1178600	Heating Analysis	2006-06-01	2007-05-31	10.82	.99	5%	No	No	2.52	17.00
A05-0120	1037859	Heating Analysis	2006-04-11	2007-04-10	5.69	.94	23%	No	No	1.40	17.00
A05-0122	711233	Heating Analysis	2005-12-01	2006-11-30	7.88	.84	14%	No	No	.85	17.00
A05-0123	734697	Heating Analysis	2006-08-09	2007-09-10	2.49	.78	34%	No	No	.71	16.00
A05-0125	623999	Heating Analysis	2007-06-29	2008-06-30	2.38	1.00	3%	No	No	.70	16.50
A05-0131	1178474	Heating Analysis	2006-05-01	2007-04-30	47.95	.89	8%	No	No	2.77	17.50
A05-0132	798495	Heating Analysis	2007-09-22	2008-09-19	-.01	.98	11%	No	No	.72	16.50
A05-0133	1179701	Heating Analysis	2006-09-01	2007-08-31	2.14	.98	9%	No	No	1.57	17.50
A05-0134	1178602	Heating Analysis	2006-09-01	2007-08-31	2.63	.99	6%	No	No	1.46	18.00

Site Name	Account Number	Model Name	Start	End	Base Load	R2	CV(RMSE)	Offsets	Weights	Heating Slope	Heating Balance Point
A05-0136	1323619	Heating Analysis	2006-10-01	2007-09-30	4.22	.95	13%	No	No	1.34	16.00
A05-0137	1323616	Heating Analysis	2006-09-01	2007-08-31	5.81	1.00	4%	No	No	1.64	15.50
A05-0138	1323620	Heating Analysis	2006-09-01	2007-08-31	2.64	.98	7%	No	No	.68	18.00
A05-0140	665969	Heating Analysis	2006-11-01	2007-10-31	7.42	.93	12%	No	No	1.63	17.50
A05-0144	498924	Non-Weather Related	2006-07-01	2007-07-03	10.64	.00	0%	Yes	No		
A05-0150	623719	Heating Analysis	2006-06-29	2007-06-27	3.49	.97	15%	No	No	1.04	17.00
A05-0154	1580407	Heating Analysis	2006-03-09	2007-03-07	2.72	.88	46%	No	No	1.03	17.50
A05-0155	1178582	Heating Analysis	2006-07-01	2007-06-30	7.28	.99	5%	No	No	1.98	14.50
A05-0156	1178576	Heating Analysis	2007-04-01	2008-03-31	14.39	.99	6%	No	No	6.05	15.00
A05-0159	640106	Heating Analysis	2006-08-16	2007-08-15	.38	.97	11%	No	No	.49	17.50
A05-0163	772334	Heating Analysis	2006-06-03	2007-06-01	3.16	.71	56%	No	No	3.72	11.50
A05-0169	1868083	Non-Weather Related	2007-03-14	2008-03-11	9.01	.00	0%	Yes	No		
A05-0171	298535	Heating Analysis	2006-08-18	2007-08-17	3.68	.92	18%	No	No	.97	16.00
A05-0173	127587	Heating Analysis	2007-08-22	2008-08-22	.04	.99	6%	No	No	.41	13.50
A05-0174	127587	Heating Analysis	2007-08-10	2008-08-13	.10	.99	8%	No	No	.47	14.50
A05-0176	742126	Heating Analysis	2008-05-02	2009-04-30	5.50	.97	10%	No	No	1.94	17.50
A05-0177	498155	Heating Analysis	2008-06-28	2009-06-26	4.15	.97	7%	No	No	.67	17.00
A05-0178	268955	Heating Analysis	2008-08-27	2009-08-25	.33	.99	6%	No	No	.90	15.00
A05-0180	498108	Heating Analysis	2008-04-29	2009-04-28	2.34	.70	49%	No	No	1.55	15.50
A05-0181	1126956	Heating Analysis	2008-09-03	2009-08-31	.25	.78	37%	No	No	1.08	18.50
A05-0183	736951	Heating Analysis	2008-05-10	2009-05-08	.04	.97	14%	No	No	.41	14.50
A05-0184	692350	Heating Analysis	2008-09-20	2009-10-20	.07	.92	32%	No	No	.60	13.50
A05-0188	1650898	Heating Analysis	2008-08-29	2009-08-27	15.68	.96	10%	No	No	3.17	17.00
A05-0189	858120	Heating Analysis	2008-05-28	2009-05-26	4.08	.98	9%	No	No	.74	15.00
A05-0190	564349	Heating Analysis	2008-10-01	2009-09-30	2.15	.98	8%	No	No	.59	17.00
A05-0192	1862457	Heating Analysis	2008-10-31	2009-10-28	1.35	.98	9%	No	No	.52	17.50
A05-0193	655948	Heating Analysis	2008-05-07	2009-05-05	2.86	.89	17%	No	No	.67	16.00
A05-0195	1180024	Heating Analysis	2008-09-01	2009-08-31	.44	.98	13%	No	No	2.76	15.00
A05-0196	692347	Heating Analysis	2008-04-19	2009-04-20	3.25	.77	25%	No	No	.65	16.50
A05-0197	692347	Heating Analysis	2008-05-21	2009-05-19	5.54	.96	8%	No	No	.73	14.00
A05-0206	661463	Heating Analysis	2008-05-10	2009-05-07	4.91	.62	31%	No	No	.70	17.00
A05-0210	1178607	Heating Analysis	2008-11-01	2009-10-31	11.12	.96	11%	No	No	2.99	14.00
A05-0212	1139860	Heating Analysis	2008-11-05	2009-11-03	4.32	.99	6%	No	No	1.18	18.00
A05-0213	1139861	Non-Weather Related	2008-12-05	2009-12-03	14.61	.00	0%	Yes	No		
A05-0217	323616	Heating Analysis	2008-06-19	2009-06-17	.04	.99	6%	No	No	.03	17.50
A05-0219	1777251	Heating Analysis	2007-10-31	2008-10-28	.04	.90	26%	No	No	1.42	11.00
A05-0228	623592	Heating Analysis	2008-10-29	2009-10-28	2.30	.96	12%	No	No	.74	17.00
A10-0247	1179124	Heating Analysis	2008-10-01	2009-09-30	27.48	.99	4%	No	No	3.38	17.00
A10-0251	1037617	Heating Analysis	2008-10-30	2009-10-28	3.74	.99	7%	No	No	.94	16.00
A10-0253	1946680	Heating Analysis	2008-11-08	2009-11-06	.74	.96	41%	No	No	.11	13.00
A05-0185	1178545	Heating Analysis	2008-11-01	2009-10-31	10.03	.96	10%	No	No	2.53	17.50
A05-0214	795104	Heating Analysis	2008-10-01	2009-10-28	2.65	.81	26%	No	Yes	.63	15.00
A10-0254	564907	Heating Analysis	2009-04-04	2011-03-07	13.23	.45	26%	No	No	.90	18.00
A10-0256	1780993	Automatic Heating Analysis	2009-04-18	2010-04-15	.04	.97	12%	No	Yes	.47	18.00
A10-0257	644890	Automatic Heating Analysis	2009-09-04	2010-09-07	.83	.91	17%	No	Yes	.64	18.50
A10-0258	1858605	Automatic Heating Analysis	2009-10-07	2010-10-06	.35	.96	18%	No	Yes	1.94	15.50
A10-0260	1178698	Automatic Heating Analysis	2009-06-01	2010-05-31	25.31	.92	5%	No	Yes	1.25	14.50

Site Name	Account Number	Model Name	Start	End	Base Load	R2	CV(RMSE)	Offsets	Weights	Heating Slope	Heating Balance Point
A10-0261	852111	Automatic Heating Analysis	2009-08-27	2010-08-26	.52	.85	22%	No	Yes	.16	16.00
A10-0262	623825	Heating Analysis	2009-07-28	2010-07-28	.01	.85	38%	No	No	.28	14.50
A10-0263	1667356	Automatic Heating Analysis	2009-10-01	2010-09-30	2.72	.98	8%	No	Yes	1.75	18.50
A10-0264	1180363	Automatic Heating Analysis	2009-10-01	2010-09-30	3.12	.98	7%	No	Yes	1.22	17.00
A10-0265	1180070	Automatic Heating Analysis	2009-10-01	2010-09-30	.88	.96	11%	No	Yes	.70	18.50
A10-0267	645265	Heating Analysis	2007-12-07	2008-12-05	6.07	.77	23%	No	No	1.25	12.00
A10-0268	1696560	Automatic Heating Analysis	2009-07-01	2010-06-30	3.33	.94	9%	No	Yes	.53	18.50
A10-0269	1696560	Automatic Heating Analysis	2009-09-01	2010-08-31	3.29	.97	8%	No	Yes	1.15	18.50
A10-0270	1696560	Automatic Heating Analysis	2009-09-01	2010-08-31	5.76	.96	9%	No	Yes	1.84	18.50
A10-0274	1331884	Automatic Heating Analysis	2009-09-03	2010-09-03	1.50	.95	12%	No	Yes	.52	17.50
A10-0275	498158	Automatic Heating Analysis	2009-06-27	2010-06-28	1.69	.91	15%	No	Yes	.61	18.50
A10-0276	738915	Heating Analysis	2009-06-10	2010-06-09	1.11	.95	12%	No	No	.39	17.00
A10-0279	644610	Automatic Heating Analysis	2009-10-02	2010-10-01	.13	.96	20%	No	Yes	.52	11.50
A10-0280	1277453	Automatic Heating Analysis	2009-10-01	2010-09-30	7.26	.95	10%	No	Yes	1.83	17.00
A10-0281	647250	Automatic Heating Analysis	2009-04-15	2010-04-13	.49	.97	11%	No	Yes	.40	16.00
A10-0282	734519	Heating Analysis	2009-09-09	2010-09-08	3.09	.69	33%	No	Yes	1.02	17.00
A10-0284	1420211	Automatic Heating Analysis	2009-11-28	2010-11-30	14.22	.94	6%	No	Yes	1.26	18.50
A10-0285	656160	Automatic Heating Analysis	2009-08-06	2010-08-05	2.32	.97	8%	No	Yes	1.07	16.00
A10-0286	717594	Automatic Heating Analysis	2010-03-26	2011-03-28	.06	.92	21%	No	Yes	.32	17.00
A10-0287	624058	Automatic Heating Analysis	2009-07-29	2010-07-28	.34	.98	9%	No	Yes	.19	17.50
A10-0288	624142	Automatic Heating Analysis	2009-08-28	2010-08-27	.56	.99	5%	No	Yes	.35	15.50
A10-0289	1178715	Automatic Heating Analysis	2009-11-01	2010-10-31	1.98	.99	9%	No	Yes	4.03	14.00
A10-0290	1436783	Automatic Heating Analysis	2009-01-10	2010-01-08	1.35	.93	15%	No	Yes	.51	16.50
A10-0291	1696560	Automatic Heating Analysis	2009-12-01	2010-11-30	13.02	.91	13%	No	Yes	2.37	18.50
A10-0292	1696560	Automatic Heating Analysis	2009-12-01	2010-11-30	7.22	.98	5%	No	Yes	1.52	18.50
A10-0295	497941	Automatic Heating Analysis	2009-09-09	2010-09-08	.49	.88	20%	No	Yes	.35	18.50
A10-0298	1046943	Automatic Heating Analysis	2009-08-05	2010-08-04	.56	.96	11%	No	Yes	.31	18.00
A10-0299	719547	Automatic Heating Analysis	2009-08-26	2010-08-25	.01	.97	13%	No	Yes	.36	17.00
A10-0300	1178047	Automatic Heating Analysis	2010-02-01	2011-01-31	21.49	.83	15%	No	Yes	1.70	18.50
A10-0301	498268	Automatic Heating Analysis	2009-11-28	2010-11-29	1.26	.96	12%	No	Yes	.68	16.50
A10-0302	623523	Automatic Heating Analysis	2009-11-25	2010-11-24	.14	.95	14%	No	Yes	.05	12.50
A10-0303	468790	Automatic Heating Analysis	2009-09-26	2010-09-27	3.70	.90	16%	No	Yes	1.88	18.50
A10-0304	623538	Automatic Heating Analysis	2009-11-27	2010-11-29	1.20	.86	18%	No	Yes	.40	18.50
A10-0305	1872665	Automatic Heating Analysis	2010-08-01	2011-07-31	1.52	.99	5%	No	Yes	1.06	18.50
A10-0309	519152	Automatic Heating Analysis	2009-08-06	2010-08-05	1.07	.99	5%	No	Yes	.33	15.50
A10-0311	1465255	Heating Analysis	2009-11-28	2010-12-01	.58	.75	36%	No	Yes	.23	11.50
A10-0312	623706	Automatic Heating Analysis	2009-03-27	2010-03-26	2.70	.97	9%	No	Yes	.70	16.00
A10-0315	1178593	Automatic Heating Analysis	2009-10-01	2010-09-30	9.56	.86	14%	No	Yes	1.55	18.50
A10-0316	1701887	Automatic Heating Analysis	2009-08-22	2010-08-20	.25	.91	25%	No	Yes	1.87	15.00
A10-0319	916818	Automatic Heating Analysis	2010-05-04	2011-05-03	2.11	.98	7%	No	Yes	.55	16.50
A10-0321	1425751	Automatic Heating Analysis	2010-04-14	2011-04-12	2.36	.75	17%	No	Yes	.30	18.50
A10-0322	623099	Automatic Heating Analysis	2009-10-27	2010-10-27	.06	.93	28%	No	Yes	.60	12.00
A10-0323	977053	Automatic Heating Analysis	2009-11-05	2010-11-04	2.27	.97	9%	No	Yes	.57	17.50
A10-0324	525599	Heating Analysis	2009-08-27	2010-08-26	3.96	.85	17%	No	Yes	.65	15.00
A10-0325	623528	Automatic Heating Analysis	2009-08-27	2010-08-26	1.11	.89	18%	No	Yes	.60	18.50
A10-0326	1101735	Heating Analysis	2010-10-01	2011-09-30	2.45	.94	10%	No	Yes	.29	17.00
A10-0327	852133	Automatic Heating Analysis	2009-08-27	2010-08-26	.41	.98	7%	No	Yes	.17	18.50

Site Name	Account Number	Model Name	Start	End	Base Load	R2	CV(RMSE)	Offsets	Weights	Heating Slope	Heating Balance Point
A10-0329	803163	Automatic Heating Analysis	2009-10-24	2010-10-26	.09	.91	23%	No	Yes	.43	16.50
A10-0330	1179659	Automatic Heating Analysis	2008-09-01	2009-08-31	1.35	.99	9%	No	Yes	2.26	16.50
A10-0331	803163	Automatic Heating Analysis	2008-09-30	2009-09-28	.06	.77	35%	No	Yes	.02	10.50
A10-0332	623588	Automatic Heating Analysis	2009-10-29	2010-10-27	.36	.82	28%	No	Yes	1.07	18.50
A10-0333	1485766	Heating Analysis	2009-08-28	2010-09-10	3.77	.97	8%	No	No	1.03	15.00
A10-0334	818040	Heating Analysis	2010-02-12	2011-01-13	.62	.87	39%	No	No	2.70	13.50
A10-0336	1402506	Automatic Heating Analysis	2009-09-23	2010-09-22	.04	.93	25%	No	Yes	1.42	11.50
A10-0337	1402506	Automatic Heating Analysis	2009-10-17	2010-10-15	.04	.93	25%	No	Yes	.86	13.00
A10-0340	319511	Automatic Heating Analysis	2009-12-09	2010-12-08	.84	.80	32%	No	Yes	.34	18.50
A10-0342	890137	Automatic Heating Analysis	2009-11-17	2010-11-15	2.40	.97	12%	No	Yes	1.06	11.50
A10-0343	641336	Automatic Heating Analysis	2010-06-03	2011-06-02	1.47	.89	23%	No	Yes	.68	12.00
A10-0344	1341670	Automatic Heating Analysis	2010-05-05	2011-05-03	1.23	.75	25%	No	Yes	.24	16.50
A10-0345	499404	Automatic Heating Analysis	2010-05-05	2011-05-03	1.43	.88	19%	No	Yes	.40	16.50
A10-0346	817761	Automatic Heating Analysis	2010-08-20	2011-08-19	.18	.99	6%	No	Yes	.59	14.50
A10-0347	1822951	Automatic Heating Analysis	2010-01-05	2011-01-04	.86	.99	7%	No	Yes	.46	16.50
A10-0348	1581034	Automatic Heating Analysis	2010-04-08	2011-04-06	6.58	.93	16%	No	Yes	1.12	18.50
A10-0349	645343	Automatic Heating Analysis	2009-07-07	2010-07-06	1.12	.85	21%	No	Yes	.34	16.00
A10-0352	302036	Automatic Heating Analysis	2008-10-11	2009-10-09	.05	.98	14%	No	Yes	1.72	14.50
A10-0354	1179024	Automatic Heating Analysis	2010-03-01	2011-02-28	4.53	.99	5%	No	Yes	1.96	18.50
A10-0356	480216	Automatic Heating Analysis	2009-09-02	2010-08-31	6.67	.95	11%	No	Yes	1.97	17.00
A10-0357	498358	Automatic Heating Analysis	2009-02-05	2010-02-04	5.03	.96	6%	No	Yes	.46	18.50
A11-0362	1595082	Automatic Heating Analysis	2009-11-06	2010-11-05	.01	.95	27%	No	Yes	.32	14.00
A11-0365	314644	Heating Analysis	2009-07-11	2011-07-12	10.17	.42	24%	No	No	.51	12.00
A11-0367	1014621	Automatic Heating Analysis	2009-09-05	2010-09-07	.40	.99	9%	No	Yes	1.15	14.00
A11-0369	1178128	Automatic Heating Analysis	2010-01-01	2010-12-31	4.32	.96	14%	No	Yes	1.34	16.00
A11-0373	1481561	Automatic Heating Analysis	2009-10-20	2010-10-19	.05	.96	18%	No	Yes	1.22	14.50
A11-0374	1195341	Heating Analysis	2009-12-01	2010-11-30	45.26	.92	9%	No	No	5.18	18.00
A11-0379	1401703	Heating Analysis	2008-07-22	2010-07-20	.41	.39	14%	No	No	.01	15.00
A11-0380	1792540	Automatic Heating Analysis	2010-07-07	2011-07-06	.45	.95	15%	No	Yes	.26	16.00
A11-0382	1406994	Automatic Heating Analysis	2010-09-29	2011-09-28	44.52	.80	18%	No	Yes	4.90	17.50
A11-0396	154889	Heating Analysis	2009-12-30	2010-12-29	.38	.98	10%	No	No	.19	15.50
A11-0406	1734532	Automatic Heating Analysis	2010-04-02	2011-04-01	.69	.92	16%	No	Yes	.37	18.50
A11-0413	645620	Automatic Heating Analysis	2010-05-07	2011-05-09	.39	.96	14%	No	Yes	.25	14.50
A11-0415	319019	Heating Analysis	2010-09-09	2011-08-09	2.21	.94	10%	No	Yes	.24	18.00
A11-0435	656019	Automatic Heating Analysis	2010-07-07	2011-07-06	2.80	.98	8%	No	Yes	.74	16.00
A11-0436	1890734	Automatic Heating Analysis	2010-08-07	2011-08-05	.43	.89	21%	No	Yes	.33	17.50
A11-0440	524403	Automatic Heating Analysis	2010-09-29	2011-09-28	1.25	.92	15%	No	Yes	.46	18.50
A11-0441	623974	Automatic Heating Analysis	2010-06-29	2011-06-28	2.07	.85	20%	No	Yes	.47	14.00
A11-0447	1441423	Automatic Heating Analysis	2010-08-13	2011-08-12	.06	.98	10%	No	Yes	.39	16.00
A11-0455	1733186	Automatic Heating Analysis	2010-08-12	2011-08-11	2.44	.99	5%	No	Yes	.56	16.00
A11-0457	645621	Automatic Heating Analysis	2010-08-10	2011-08-09	.52	.99	6%	No	Yes	.27	15.50
A11-0462	498664	Automatic Heating Analysis	2010-08-14	2011-08-15	1.35	.90	16%	No	Yes	.69	18.50
A11-0467	646028	Automatic Heating Analysis	2010-01-09	2011-01-07	.01	.97	12%	No	Yes	.31	18.50
A05-0001	701618	Automatic Heating Analysis	2005-02-23	2006-02-28	6.35	.94	13%	No	Yes	2.34	18.00
A05-0002	1579894	Automatic Heating Analysis	2004-05-13	2005-05-10	.02	.90	19%	No	Yes	.02	16.50
A05-0038	1178597	Automatic Heating Analysis	2005-10-01	2006-09-30	22.58	.97	6%	No	Yes	3.04	18.50
A05-0047	817996	Automatic Non-Weather Analysis	2008-03-13	2010-02-10	9.91	.06	33%	No	No	.18	16.00

Site Name	Account Number	Model Name	Start	End	Base Load	R2	CV(RMSE)	Offsets	Weights	Heating Slope	Heating Balance Point
A05-0064	647003	Automatic Heating Analysis	2005-10-07	2006-10-05	.25	.97	14%	No	Yes	.67	14.00
A05-0075	850285	Automatic Heating Analysis	2007-06-15	2008-06-15	.39	.99	7%	No	Yes	.48	15.50
A05-0090	1178795	Automatic Heating Analysis	2010-08-01	2011-07-31	28.91	.99	5%	No	Yes	6.51	14.50
A05-0091	1695358	Automatic Heating Analysis	2010-03-11	2011-03-09	.82	.97	12%	No	Yes	.41	14.50
A05-0092	622935	Automatic Heating Analysis	2007-01-03	2008-01-02	.53	.98	12%	No	Yes	.98	14.50
A05-0162	1686583	Weather Analysis	2009-02-04	2010-02-03	5.11	.97	8%	No	Yes	.71	11.50
A05-0170	333816	Automatic Heating Analysis	2006-02-04	2007-05-17	-.08	.97	12%	No	No	.80	17.50
A05-0182	735747	Automatic Heating Analysis	2009-05-07	2010-05-06	2.58	.86	13%	No	Yes	.29	18.00
A05-0191	623582	Heating Analysis	2007-09-28	2008-09-26	1.63	.99	5%	No	No	.41	15.50
A05-0198	1686583	Automatic Heating Analysis	2009-03-03	2010-03-02	6.23	.91	15%	No	Yes	1.36	16.50
A05-0199	859459	Automatic Heating Analysis	2008-09-27	2009-09-25	3.28	.99	6%	No	Yes	.94	15.00
A05-0201	1196416	Automatic Heating Analysis	2007-10-01	2008-09-30	1.22	.92	22%	No	Yes	1.73	14.50
A05-0204	656452	Automatic Heating Analysis	2008-10-08	2009-10-05	2.36	.98	10%	No	Yes	1.31	17.50
A05-0209	1178128	Automatic Heating Analysis	2008-07-09	2009-07-06	.56	.92	20%	No	Yes	.15	17.50
A05-0211	1696560	Automatic Heating Analysis	2009-02-01	2010-01-31	8.28	.98	6%	No	Yes	1.27	18.50
A05-0216	1179211	Automatic Heating Analysis	2009-08-01	2010-07-31	6.72	.88	18%	No	Yes	2.21	17.50
A05-0218	125067	Automatic Heating Analysis	2009-09-10	2010-09-09	.00	.96	18%	No	Yes	.15	14.50
A05-0220	1696560	Automatic Heating Analysis	2008-12-01	2009-11-30	4.57	.98	8%	No	Yes	1.77	18.50
A05-0221	1696560	Automatic Heating Analysis	2009-01-01	2009-12-31	13.97	1.00	2%	No	Yes	2.63	18.50
A05-0222	1696560	Automatic Heating Analysis	2009-01-01	2009-12-31	23.07	.96	8%	No	Yes	3.45	18.00
A05-0223	1696560	Automatic Heating Analysis	2009-01-01	2009-12-31	4.35	.99	4%	No	Yes	.58	18.50
A05-0224	1696560	Automatic Heating Analysis	2009-01-01	2009-12-31	4.01	.98	8%	No	Yes	1.13	18.50
A05-0225	1178808	Automatic Heating Analysis	2009-02-01	2010-01-31	1.95	.94	23%	No	Yes	6.52	13.50
A05-0227	890126	Automatic Heating Analysis	2009-12-15	2010-12-13	1.72	.90	20%	No	Yes	1.52	17.50
A05-0229	4988826	Automatic Heating Analysis	2009-02-13	2010-02-15	7.30	.94	12%	No	Yes	2.34	18.50
A05-0230	1180355	Automatic Heating Analysis	2009-09-01	2010-08-31	121.48	.99	3%	No	Yes	27.68	18.50
A05-0235	583015	Automatic Heating Analysis	2008-11-18	2009-11-16	.03	.94	24%	No	Yes	.57	14.50
A05-0237	316544	Automatic Heating Analysis	2009-01-09	2010-01-08	.18	1.00	7%	No	Yes	.77	14.00
A05-0238	1179626	Automatic Heating Analysis	2009-02-01	2010-01-31	.30	.99	7%	No	Yes	.64	17.50

APPENDIX B: Base Period Analysis

Due to large file size, this Appendix is provided as a separate file

APPENDIX C: Last Reading Dates

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A05-0001		Gas-0001	Install Date: 03/01/2006	Natural Gas	701618	290710	2012-05-31	31	1,055	0	210
A05-0002		Gas-0002	Install Date: 05/01/2005	Natural Gas	1579894	706561	2012-06-08	31	5	0	202
A05-0003		GAS-0003	Install Date: 09/09/2005	Natural Gas	1178691	406662	2012-05-31	31	225	0	210
A05-0004		GAS-0004	Install Date: 09/09/2005	Natural Gas	1178545	254236	2012-05-31	31	178	0	210
A05-0005		GAS-0005	Install Date: 09/09/2005	Natural Gas	1178546	610023	2012-05-31	31	163	0	210
A05-0006		GAS-0006	Install Date: 08/02/2005	Natural Gas	1179373	704208	2012-05-31	31	382	0	210
A05-0007		GAS-0007	Install Date: 10/01/2006	Natural Gas	168567	51073	2012-05-31	29	192	0	210
A05-0008		GAS-0008	Install Date: 11/01/2005	Natural Gas	1850990	280132	2012-05-31	31	337	0	210
A05-0009		GAS-0009	Install Date: 12/12/2005	Natural Gas	367968	36937	2007-05-02	6	0	0	2066
A05-0010		GAS-0010	Install Date: 09/01/2005	Natural Gas	1178913	266683	2012-05-31	31	2,605	0	210
A05-0011		GAS-0011	Install Date: 04/02/2007	Natural Gas	1179742	468596	2012-06-13	29	287	0	197
A05-0012		GAS-0012	Install Date: 09/20/2005	Natural Gas	500068	387051	2012-06-11	33	58	0	199
A05-0015		GAS-0015	Install Date: 09/01/2008	Natural Gas	686646	472188	2012-06-14	30	52	0	196
A05-0017		GAS-0017	Install Date: 09/01/2005	Natural Gas	772342	684089	2012-06-22	28	37	0	188
A05-0019		GAS-0019	Install Date: 10/05/2005	Natural Gas	623020	256597	2012-06-26	29	68	0	184
A05-0020		GAS-0020	Install Date: 10/05/2005	Natural Gas	1016484	413028	2012-06-11	32	163	0	199
A05-0021		GAS-0021	Install Date: 10/24/2005	Natural Gas	498623	399773	2012-06-11	32	73	0	199
A05-0022		GAS-0022	Install Date: 01/05/2006	Natural Gas	1696560	311848	2012-05-31	31	159	0	210
A05-0023		GAS-0023	Install Date: 11/01/2005	Natural Gas	372654	35729	2012-06-21	29	10	0	189
A05-0024		GAS-0024	Install Date: 11/03/2006	Natural Gas	1234106	705498	2012-05-31	31	668	0	210
A05-0025		Gas-0025	Install Date: 12/23/2005	Natural Gas	1304924	839250	2012-05-31	31	172	0	210
A05-0026		GAS-0026	Install Date: 12/07/2006	Natural Gas	639998	423077	2012-06-12	32	43	0	198
A05-0027		GAS-0027	Install Date: 11/22/2005	Natural Gas	646949	525328	2012-06-04	32	124	0	206
A05-0028		GAS-0028	Install Date: 06/29/2006	Natural Gas	565844	545094	2012-06-25	28	132	0	185
A05-0029		GAS-0029	Install Date: 10/26/2006	Natural Gas	1025771	617167	2012-06-12	32	21	0	198
A05-0030		GAS-0030	Install Date: 10/01/2006	Natural Gas	522035	290739	2012-06-20	29	29	0	190
A05-0031		GAS-0031	Install Date: 12/23/2005	Natural Gas	481313	318638	2012-06-05	32	118	0	205
A05-0032		GAS-0032	Install Date: 09/30/2006	Natural Gas	1179455	612048	2012-05-31	31	882	0	210
A05-0033		GAS-0033	Install Date: 02/22/2006	Natural Gas	1696560	310861	2012-05-31	31	238	0	210
A05-0034		GAS-0034	Install Date: 10/05/2006	Natural Gas	847135	522033	2012-06-04	32	6	0	206
A05-0035		GAS-0035	Install Date: 01/04/2007	Natural Gas	151124	236764	2012-06-04	32	119	0	206
A05-0037		GAS-0037	Install Date: 08/23/2006	Natural Gas	1307154	313476	2012-06-19	28	85	0	191
A05-0038		Gas-0038	Install Date: 09/20/2006	Natural Gas	1178597	539038	2012-05-31	31	807	0	210
A05-0040		GAS-0040	Install Date: 03/16/2006	Natural Gas	1639618	811250	2012-05-31	31	1,045	0	210
A05-0041		GAS-0041	Install Date: 04/06/2006	Natural Gas	623991	308349	2012-06-26	29	92	0	184

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A05-0042		GAS-0042	Install Date: 04/06/2006	Natural Gas	623990	308141	2012-06-26	29	69	0	184
A05-0043		GAS-0043	Install Date: 05/01/2007	Natural Gas	1696560	670431	2012-05-31	31	166	0	210
A05-0044		GAS-0044	Install Date: 09/05/2006	Natural Gas	622935	388193	2012-05-11	28	96	0	230
A05-0045		GAS-0045	Install Date: 08/11/2006	Natural Gas	1178526	317893	2012-05-31	31	682	0	210
A05-0046		GAS-0046	Install Date: 02/05/2007	Natural Gas	1179092	311883	2012-05-31	31	750	0	210
A05-0047		Gas-0047	Install Date: 03/09/2010	Natural Gas	817996	390048	2012-06-11	33	338	0	199
A05-0048		GAS-0048	Install Date: 09/25/2006	Natural Gas	622935	403864	2012-05-11	28	113	0	230
A05-0050		GAS-0050	Install Date: 06/12/2007	Natural Gas	498499	360590	2012-06-06	29	108	0	204
A05-0051		GAS-0051	Install Date: 10/06/2006	Natural Gas	1247800	409296	2012-06-11	32	328	0	199
A05-0052		GAS-0052	Install Date: 08/01/2006	Natural Gas	1317022	304098	2012-06-25	31	175	0	185
A05-0053		GAS-0053	Install Date: 08/31/2006	Natural Gas	623537	282017	2012-06-25	31	229	0	185
A05-0054		GAS-0054	Install Date: 06/20/2006	Natural Gas	803143	332426	2012-05-15	28	293	0	226
A05-0055		GAS-0055	Install Date: 06/20/2006	Natural Gas	803143	332435	2012-05-15	28	318	0	226
A05-0056		GAS-0056	Install Date: 06/20/2006	Natural Gas	803143	332417	2012-05-15	28	89	0	226
A05-0057		GAS-0057	Install Date: 06/20/2006	Natural Gas	803143	332425	2012-05-15	28	80	0	226
A05-0058		GAS-0058	Install Date: 06/20/2006	Natural Gas	803143	332349	2012-05-15	28	128	0	226
A05-0059		GAS-0059	Install Date: 06/20/2006	Natural Gas	803143	332382	2012-05-15	28	155	0	226
A05-0060		GAS-0060	Install Date: 06/20/2006	Natural Gas	803143	332383	2012-05-15	28	139	0	226
A05-0061		GAS-0061	Install Date: 06/20/2006	Natural Gas	803143	332384	2012-05-15	28	157	0	226
A05-0062		GAS-0062	Install Date: 10/14/2006	Natural Gas	1196428	522363	2012-05-31	31	402	0	210
A05-0064		Gas-0064	Install Date: 10/01/2006	Natural Gas	647003	525699	2012-06-04	32	74	0	206
A05-0065		GAS-0065	Install Date: 12/18/2006	Natural Gas	509483	275850	2012-06-25	31	148	0	185
A05-0066		GAS-0066	Install Date: 11/24/2006	Natural Gas	1178446	30724	2012-06-01	30	167	0	209
A05-0068		GAS-0068	Install Date: 09/01/2006	Natural Gas	1298386	307235	2012-05-31	31	256	0	210
A05-0069		GAS-0069	Install Date: 09/05/2006	Natural Gas	1178545	414759	2012-05-31	31	639	0	210
A05-0070		GAS-0070	Install Date: 09/05/2006	Natural Gas	1178545	608173	2012-05-31	31	399	0	210
A05-0072		GAS-0072	Install Date: 10/27/2006	Natural Gas	497887	278451	2012-05-31	31	203	0	210
A05-0075		Gas-0075	Install Date: 06/06/2008	Natural Gas	850285	644376	2012-05-14	28	79	0	227
A05-0077		GAS-0077	Install Date: 11/22/2006	Natural Gas	358232	64492	2012-06-08	30	14	0	202
A05-0079		GAS-0079	Install Date: 07/07/2006	Natural Gas	772955	606229	2012-05-31	31	355	0	210
A05-0080		GAS-0080	Install Date: 08/31/2006	Natural Gas	1121989	256346	2012-05-31	31	130	0	210
A05-0081		GAS-0081	Install Date: 09/13/2006	Natural Gas	1696560	286361	2012-05-31	31	1,439	0	210
A05-0082		GAS-0082	Install Date: 10/26/2006	Natural Gas	1696560	285146	2012-05-31	31	506	0	210
A05-0084		GAS-0084	Install Date: 10/18/2006	Natural Gas	772342	645039	2012-06-13	29	62	0	197
A05-0085		GAS-0085	Install Date: 07/05/2006	Natural Gas	647014	525780	2012-06-04	32	177	0	206

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A05-0086		GAS-0086	Install Date: 05/31/2007	Natural Gas	318777	191021	2012-06-13	30	128	0	197
A05-0087		GAS-0087	Install Date: 01/16/2007	Natural Gas	1179883	779272	2012-05-31	31	268	0	210
A05-0089		GAS-0089	Install Date: 11/26/2006	Natural Gas	1701887	45157	2012-05-15	28	0	0	226
A05-0090		Gas-0090	Install Date: 07/26/2011	Natural Gas	1178795	508368	2012-05-31	31	1,311	0	210
A05-0091		Gas-0091	Install Date: 03/09/2011	Natural Gas	1695358	984590	2012-06-06	30	61	0	204
A05-0092		Gas-0092	Install Date: 01/01/2008	Natural Gas	622935	497490	2012-04-30	32	238	0	241
A05-0093		GAS-0093	Install Date: 11/01/2006	Natural Gas	623591	285521	2012-05-31	31	194	0	210
A05-0094		GAS-0094	Install Date: 09/01/2006	Natural Gas	1196426	508110	2012-06-01	30	102	0	209
A05-0095		GAS-0095	Install Date: 08/01/2007	Natural Gas	267929	160979	2012-05-31	30	167	0	210
A05-0096		GAS-0096	Install Date: 08/11/2006	Natural Gas	168568	51072	2012-05-31	29	66	0	210
A05-0097		Gas-0097	Install Date: 08/01/2007	Natural Gas	772342	973983	2012-06-20	28	24	0	190
A05-0098		GAS-0098	Install Date: 12/16/2006	Natural Gas	1179918	782766	2012-06-25	28	311	0	185
A05-0099		GAS-0099	Install Date: 10/12/2006	Natural Gas	1179439	652994	2012-05-31	31	525	0	210
A05-0100		GAS-0100	Install Date: 12/07/2006	Natural Gas	950726	771423	2012-06-05	29	63	0	205
A05-0101		GAS-0101	Install Date: 12/07/2006	Natural Gas	1891403	266117	2012-06-22	29	82	0	188
A05-0102		GAS-0102	Install Date: 06/01/2007	Natural Gas	1179472	702112	2012-05-31	31	2,340	0	210
A05-0103		GAS-0103	Install Date: 05/24/2007	Natural Gas	647243	449169	2012-05-31	30	139	0	210
A05-0104		GAS-0104	Install Date: 04/19/2007	Natural Gas	1696560	483716	2012-05-31	31	139	0	210
A05-0105		GAS-0105	Install Date: 04/27/2007	Natural Gas	647243	266076	2012-05-30	30	156	0	211
A05-0106		GAS-0106	Install Date: 04/27/2007	Natural Gas	1696560	265806	2012-05-31	31	189	0	210
A05-0109		GAS-0109	Install Date: 11/03/2006	Natural Gas	656898	313159	2012-06-05	32	229	0	205
A05-0110		GAS-0110	Install Date: 10/12/2006	Natural Gas	1300786	721346	2012-05-31	31	139	0	210
A05-0112		GAS-0112	Install Date: 10/18/2006	Natural Gas	1178736	505743	2012-05-31	31	251	0	210
A05-0114		GAS-0114	Install Date: 01/29/2007	Natural Gas	1696560	290590	2012-05-31	31	614	0	210
A05-0115		GAS-0115	Install Date: 04/18/2007	Natural Gas	1696560	257082	2012-05-31	31	396	0	210
A05-0116		GAS-0116	Install Date: 04/18/2007	Natural Gas	1240604	737983	2012-06-06	30	169	0	204
A05-0118		Gas-0118	Install Date: 12/12/2006	Natural Gas	1275638	963080	2012-06-21	29	122	0	189
A05-0119		GAS-0119	Install Date: 06/28/2007	Natural Gas	1178600	279229	2012-05-31	31	498	0	210
A05-0120		GAS-0120	Install Date: 04/25/2007	Natural Gas	1037859	480833	2012-05-31	31	323	0	210
A05-0122		GAS-0122	Install Date: 12/01/2006	Natural Gas	711233	330288	2012-05-31	31	312	0	210
A05-0123		GAS-0123	Install Date: 10/01/2007	Natural Gas	734697	473191	2012-06-05	32	113	0	205
A05-0125		GAS-0125	Install Date: 08/05/2008	Natural Gas	623999	309195	2012-06-26	29	143	0	184
A05-0131		GAS-0131	Install Date: 05/01/2007	Natural Gas	1178474	257372	2012-05-31	31	2,016	0	210
A05-0132		GAS-0132	Install Date: 10/01/2008	Natural Gas	798495	688856	2012-06-18	32	76	0	192
A05-0133		GAS-0133	Install Date: 09/01/2007	Natural Gas	1179701	785675	2012-05-31	31	215	0	210

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A05-0134		GAS-0134	Install Date: 09/24/2007	Natural Gas	1178602	541514	2012-05-31	31	292	0	210
A05-0136		GAS-0136	Install Date: 10/01/2007	Natural Gas	1323619	299702	2012-05-31	31	257	0	210
A05-0137		GAS-0137	Install Date: 09/01/2007	Natural Gas	1323616	478417	2012-05-31	31	305	0	210
A05-0138		GAS-0138	Install Date: 09/01/2007	Natural Gas	1323620	420870	2012-05-31	31	131	0	210
A05-0139		Gas-0139	Install Date: 02/01/2008	Natural Gas	1540344	970083	2012-06-06	30	97	0	204
A05-0140		GAS-0140	Install Date: 11/21/2007	Natural Gas	665969	365653	2012-05-31	31	547	0	210
A05-0141		Gas-0141	Install Date: 07/01/2008	Natural Gas	1783297	977045	2012-06-22	28	166	0	188
A05-0142		Gas-0142	Install Date: 10/26/2007	Natural Gas	772342	955786	2012-06-25	31	33	0	185
A05-0143		Gas-0143	Install Date: 12/01/2008	Natural Gas	1179495	677790	2008-05-31	31	237	0	1671
A05-0144		GAS-0144	Install Date: 07/25/2007	Natural Gas	498924	496208	2012-06-28	29	145	0	182
A05-0150		GAS-0150	Install Date: 08/01/2007	Natural Gas	623719	295067	2012-06-25	31	188	0	185
A05-0154		GAS-0154	Install Date: 04/07/2008	Natural Gas	1580407	515881	2012-05-31	31	164	0	210
A05-0155		GAS-0155	Install Date: 07/17/2007	Natural Gas	1178582	536113	2012-05-31	31	284	0	210
A05-0156		GAS-0156	Install Date: 04/05/2008	Natural Gas	1178576	302558	2012-05-31	31	872	0	210
A05-0158		Gas-0158	Install Date: 11/19/2009	Natural Gas	772342	1012592	2012-06-18	32	29	0	192
A05-0159		GAS-0159	Install Date: 08/30/2007	Natural Gas	640106	423566	2012-06-12	32	85	0	198
A05-0162		Gas-0162	Install Date: 04/09/2010	Natural Gas	1686583	986989	2012-06-01	30	185	0	209
A05-0163		GAS-0163	Install Date: 11/02/2007	Natural Gas	772334	605934	2012-05-30	29	411	0	211
A05-0166		Gas-0166	Install Date: 05/01/2009	Natural Gas	1627947	992547	2012-05-31	31	510	0	210
A05-0167		Gas-0167	Install Date: 03/01/2008	Natural Gas	1627947	988286	2012-05-31	31	264	0	210
A05-0169		GAS-0169	Install Date: 04/03/2008	Natural Gas	1868083	272939	2012-05-31	31	299	0	210
A05-0170		Gas-0170	Install Date: 06/22/2007	Natural Gas	333816	82262	2012-05-31	30	171	0	210
A05-0171		GAS-0171	Install Date: 10/01/2008	Natural Gas	298535	197335	2012-05-31	31	130	0	210
A05-0173		GAS-0173	Install Date: 09/01/2008	Natural Gas	127587	14291	2012-05-17	28	57	0	224
A05-0174		GAS-0174	Install Date: 09/02/2008	Natural Gas	127587	10891	2012-06-05	29	34	0	205
A05-0175		Gas-0175	Install Date: 01/15/2009	Natural Gas	1686583	297027	2012-11-01	30	59	0	56
A05-0176		GAS-0176	Install Date: 05/01/2009	Natural Gas	742126	510439	2012-05-30	30	407	0	211
A05-0177		GAS-0177	Install Date: 07/01/2009	Natural Gas	498155	307218	2012-06-26	29	133	0	184
A05-0178		GAS-0178	Install Date: 09/01/2009	Natural Gas	268955	161485	2012-05-24	29	103	0	217
A05-0180		GAS-0180	Install Date: 05/22/2009	Natural Gas	498108	304568	2012-06-25	31	228	0	185
A05-0181		GAS-0181	Install Date: 09/01/2009	Natural Gas	1126956	490831	2012-06-28	29	136	0	182
A05-0182		Gas-0182	Install Date: 05/09/2010	Natural Gas	735747	478440	2012-06-05	32	96	0	205
A05-0183		GAS-0183	Install Date: 06/01/2009	Natural Gas	736951	482862	2012-06-07	30	15	0	203
A05-0184		GAS-0184	Install Date: 11/04/2009	Natural Gas	692350	325339	2012-06-15	30	54	0	195
A05-0185		GAS-0185	Install Date: 11/02/2009	Natural Gas	1178545	399907	2012-05-31	31	706	0	210

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A05-0188		GAS-0188	Install Date: 09/01/2009	Natural Gas	1650898	948964	2012-06-08	30	813	0	202
A05-0189		GAS-0189	Install Date: 07/02/2009	Natural Gas	858120	562819	2012-06-22	28	118	0	188
A05-0190		GAS-0190	Install Date: 10/01/2009	Natural Gas	564349	462258	2012-06-13	29	96	0	197
A05-0191		Gas-0191	Install Date: 09/01/2012	Natural Gas	623582	285143	2012-06-25	31	56	0	185
A05-0192		GAS-0192	Install Date: 11/17/2009	Natural Gas	1862457	267973	2012-06-26	28	105	0	184
A05-0193		GAS-0193	Install Date: 06/29/2009	Natural Gas	655948	309516	2012-06-04	32	183	0	206
A05-0195		GAS-0195	Install Date: 09/23/2009	Natural Gas	1180024	726355	2012-05-31	31	167	0	210
A05-0196		GAS-0196	Install Date: 06/09/2009	Natural Gas	692347	325654	2012-06-15	30	122	0	195
A05-0197		GAS-0197	Install Date: 06/09/2009	Natural Gas	692347	326188	2012-06-15	30	172	0	195
A05-0198		Gas-0198	Install Date: 02/28/2010	Natural Gas	1686583	467934	2012-06-28	29	202	0	182
A05-0199		Gas-0199	Install Date: 09/30/2009	Natural Gas	859459	565898	2012-06-22	28	130	0	188
A05-0201		Gas-0201	Install Date: 10/14/2008	Natural Gas	1196416	464925	2012-05-31	31	119	0	210
A05-0204		Gas-0204	Install Date: 10/02/2009	Natural Gas	656452	311832	2012-06-04	32	283	0	206
A05-0206		GAS-0206	Install Date: 06/01/2009	Natural Gas	661463	345442	2012-05-31	31	452	0	210
A05-0208		Gas-0208	Install Date: 08/08/2012	Natural Gas	1178491	313066	2012-05-31	31	552	0	210
A05-0209		Gas-0209	Install Date: 1 in yr 2009/2010/2011	Natural Gas	1178128	308815	2012-06-04	32	53	0	206
A05-0210		GAS-0210	Install Date: 11/06/2009	Natural Gas	1178607	541687	2012-05-31	31	636	0	210
A05-0211		Gas-0211	Install Date: 02/02/2010	Natural Gas	1696560	295211	2012-05-31	31	383	0	210
A05-0212		GAS-0212	Install Date: 12/03/2009	Natural Gas	1139860	675822	2012-06-01	30	229	0	209
A05-0213		GAS-0213	Install Date: 12/03/2009	Natural Gas	1139861	675784	2012-06-01	30	227	0	209
A05-0214		GAS-0214	Install Date: 11/30/2009	Natural Gas	795104	676296	2012-06-26	28	100	0	184
A05-0216		Gas-0216	Install Date: 08/10/2010	Natural Gas	1179211	428189	2012-05-31	31	452	0	210
A05-0217		GAS-0217	Install Date: 08/12/2009	Natural Gas	323616	67113	2012-06-15	30	2	0	195
A05-0218		Gas-0218	Install Date: 08/31/2010	Natural Gas	125067	11827	2012-06-07	29	12	0	203
A05-0219		GAS-0219	Install Date: 12/04/2009	Natural Gas	1777251	288862	2012-06-25	31	5	0	185
A05-0220		Gas-0220	Install Date: 12/14/2009	Natural Gas	1696560	257203	2012-05-31	31	435	0	210
A05-0221		Gas-0221	Install Date: 12/28/2009	Natural Gas	1696560	460627	2012-05-31	31	478	0	210
A05-0222		Gas-0222	Install Date: 12/21/2009	Natural Gas	1696560	264610	2012-05-31	31	1,358	0	210
A05-0223		Gas-0223	Install Date: 12/28/2009	Natural Gas	1696560	288395	2012-05-31	31	151	0	210
A05-0224		Gas-0224	Install Date: 12/28/2009	Natural Gas	1696560	675957	2012-05-31	31	233	0	210
A05-0225		Gas-0225	Install Date: 01/19/2010	Natural Gas	1178808	321898	2012-05-31	31	467	0	210
A05-0227		Gas-0227	Install Date: 12/09/2010	Natural Gas	890126	645733	2012-06-12	32	381	0	198
A05-0228		GAS-0228	Install Date: 11/01/2009	Natural Gas	623592	285568	2012-06-25	31	145	0	185
A05-0229		Gas-0229	Install Date: 02/17/2010	Natural Gas	4988826	414476	2012-06-12	32	749	0	198
A05-0230		Gas-0230	Install Date: 09/10/2010	Natural Gas	1180355	331194	2012-05-31	31	11,330	0	210

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A05-0233		Gas-0233	Install Date: 05/14/2010	Natural Gas	1833456	1016695	2012-06-08	31	37	0	202
A05-0235		Gas-0235	Install Date: 11/12/2009	Natural Gas	583015	787691	2012-05-14	28	51	0	227
A05-0237		Gas-0237	Install Date: 12/24/2009	Natural Gas	316544	177505	2012-06-06	30	35	0	204
A05-0238		Gas-0238	Install Date: 01/28/2010	Natural Gas	1179626	458982	2012-05-29	29	100	0	212
A10-0247		GAS-0247	Install Date: 10/06/2009	Natural Gas	1179124	703441	2012-05-31	31	988	0	210
A10-0251		GAS-0251	Install Date: 11/01/2009	Natural Gas	1037617	306259	2012-06-26	29	202	0	184
A10-0253		GAS-0253	Install Date: 12/15/2009	Natural Gas	1946680	58610	2012-06-06	30	56	0	204
A10-0254		Gas-0254	Install Date: 03/08/2011	Natural Gas	564907	523253	2012-06-05	32	364	0	205
A10-0256		Gas-0256	Install Date: 04/28/2010	Natural Gas	1780993	466700	2012-06-13	29	46	0	197
A10-0257		Gas-0257	Install Date: 09/08/2010	Natural Gas	644890	502998	2012-06-05	33	89	0	205
A10-0258		Gas-0258	Install Date: 10/07/2010	Natural Gas	1858605	316423	2012-06-05	29	88	0	205
A10-0260		Gas-0260	Install Date: 05/25/2010	Natural Gas	1178698	496391	2012-05-31	31	672	0	210
A10-0261		Gas-0261	Install Date: 09/10/2010	Natural Gas	852111	543472	2012-06-25	28	21	0	185
A10-0262		Gas-0262	Install Date: 09/08/2010	Natural Gas	623825	298670	2012-06-25	28	16	0	185
A10-0263		Gas-0263	Install Date: 10/12/2010	Natural Gas	1667356	276519	2012-05-31	31	408	0	210
A10-0264		Gas-0264	Install Date: 10/12/2010	Natural Gas	1180363	306576	2012-05-31	31	230	0	210
A10-0265		Gas-0265	Install Date: 10/12/2010	Natural Gas	1180070	306231	2012-05-31	31	136	0	210
A10-0266		Gas-0266	Install Date: 10/10/2012	Natural Gas	659656	336383	2012-06-06	29	24	0	204
A10-0267		Gas-0267	Install Date: 02/15/2010	Natural Gas	645265	505806	2012-05-31	31	247	0	210
A10-0268		Gas-0268	Install Date: 07/04/2010	Natural Gas	1696560	768886	2012-05-31	31	128	0	210
A10-0269		Gas-0269	Install Date: 08/31/2010	Natural Gas	1696560	481798	2012-05-31	31	219	0	210
A10-0270		Gas-0270	Install Date: 08/26/2010	Natural Gas	1696560	285146	2012-05-31	31	506	0	210
A10-0274		Gas-0274	Install Date: 08/30/2010	Natural Gas	1331884	303042	2012-06-01	30	112	0	209
A10-0275		Gas-0275	Install Date: 07/04/2010	Natural Gas	498158	311850	2012-06-26	29	163	0	184
A10-0276		Gas-0276	Install Date: 07/04/2010	Natural Gas	738915	490345	2012-06-07	30	68	0	203
A10-0278		Gas-0278	Install Date: 07/29/2010	Natural Gas	491506	1025108	2012-06-11	32	65	0	199
A10-0279		Gas-0279	Install Date: 10/13/2010	Natural Gas	644610	498769	2012-05-31	30	17	0	210
A10-0280		Gas-0280	Install Date: 10/14/2010	Natural Gas	1277453	323282	2012-05-31	31	263	0	210
A10-0281		Gas-0281	Install Date: 04/10/2010	Natural Gas	647250	403254	2012-06-11	32	36	0	199
A10-0282		Gas-0282	Install Date: 09/14/2010	Natural Gas	734519	472226	2012-06-06	30	156	0	204
A10-0283		Gas-0283	Install Date: 09/09/2011	Natural Gas	1964809	1040485	2012-05-31	31	516	0	210
A10-0284		Gas-0284	Install Date: 11/17/2010	Natural Gas	1420211	948068	2012-06-27	30	537	0	183
A10-0285		Gas-0285	Install Date: 09/10/2010	Natural Gas	656160	310542	2012-06-04	32	152	0	206
A10-0286		Gas-0286	Install Date: 03/17/2011	Natural Gas	717594	366396	2012-06-22	28	26	0	188
A10-0287		Gas-0287	Install Date: 08/13/2010	Natural Gas	624058	312777	2012-06-26	29	25	0	184

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	**Code**	**Name**	**Description**	**Type**	**Account Number**	**Premise ID**	**Date**	**Days**	**Consumption**	**Cost**	**Days Since**
A10-0288		Gas-0288	Install Date: 08/26/2010	Natural Gas	624142	317120	2012-06-26	29	54	0	184
A10-0289		Gas-0289	Install Date: 10/31/2010	Natural Gas	1178715	778507	2012-05-31	31	306	0	210
A10-0290		Gas-0290	Install Date: 01/01/2010	Natural Gas	1436783	891332	2012-06-06	30	43	0	204
A10-0291		Gas-0291	Install Date: 11/23/2010	Natural Gas	1696560	670678	2012-05-31	31	634	0	210
A10-0292		Gas-0292	Install Date: 12/13/2010	Natural Gas	1696560	372456	2012-05-31	31	360	0	210
A10-0295		Gas-0295	Install Date: 09/10/2010	Natural Gas	497941	472257	2012-06-06	30	49	0	204
A10-0297		Gas-0297	Install Date: 09/16/2011	Natural Gas	497860	259589	2012-05-31	31	269	0	210
A10-0298		Gas-0298	Install Date: 08/01/2010	Natural Gas	1046943	462683	2012-05-31	29	70	0	210
A10-0299		Gas-0299	Install Date: 09/10/2010	Natural Gas	719547	383693	2012-06-22	30	19	0	188
A10-0300		Gas-0300	Install Date: 02/02/2011	Natural Gas	1178047	12121	2012-05-31	31	1,312	0	210
A10-0301		Gas-0301	Install Date: 12/08/2010	Natural Gas	498268	307203	2012-06-26	29	111	0	184
A10-0302		Gas-0302	Install Date: 12/08/2010	Natural Gas	623523	280658	2012-06-21	29	9	0	189
A10-0303		Gas-0303	Install Date: 10/07/2010	Natural Gas	468790	282373	2012-06-25	31	425	0	185
A10-0304		Gas-0304	Install Date: 12/07/2010	Natural Gas	623538	282312	2012-05-25	29	97	0	216
A10-0305		Gas-0305	Install Date: 08/09/2011	Natural Gas	1872665	424701	2012-09-30	30	145	0	88
A10-0307		Gas-0307	Install Date: 09/23/2011	Natural Gas	812018	351056	2012-06-14	30	17	0	196
A10-0309		Gas-0309	Install Date: 08/01/2010	Natural Gas	519152	781658	2012-06-04	31	42	0	206
A10-0311		Gas-0311	Install Date: 11/30/2010	Natural Gas	1465255	948177	2012-05-31	31	43	0	210
A10-0312		Gas-0312	Install Date: 04/07/2010	Natural Gas	623706	293421	2012-06-25	31	129	0	185
A10-0315		Gas-0315	Install Date: 10/15/2010	Natural Gas	1178593	537091	2012-05-31	31	745	0	210
A10-0316		Gas-0316	Install Date: 08/30/2010	Natural Gas	1701887	33345	2012-05-18	28	0	0	223
A10-0317		Gas-0317	Install Date: 06/28/2011	Natural Gas	1701887	89226	2012-10-03	29	8	0	85
A10-0319		Gas-0319	Install Date: 05/02/2011	Natural Gas	916818	719214	2012-05-31	29	222	0	210
A10-0321		Gas-0321	Install Date: 04/18/2011	Natural Gas	1425751	907989	2012-06-11	32	96	0	199
A10-0322		Gas-0322	Install Date: 10/12/2010	Natural Gas	623099	258537	2012-06-25	32	8	0	185
A10-0323		Gas-0323	Install Date: 11/20/2010	Natural Gas	977053	614380	2012-06-04	32	160	0	206
A10-0324		Gas-0324	Install Date: 09/09/2010	Natural Gas	525599	649083	2012-05-31	31	141	0	210
A10-0325		Gas-0325	Install Date: 09/10/2010	Natural Gas	623528	281329	2012-06-25	28	147	0	185
A10-0326		Gas-0326	Install Date: 10/01/2011	Natural Gas	1101735	272779	2012-10-30	32	13	0	58
A10-0327		Gas-0327	Install Date: 09/10/2010	Natural Gas	852133	543518	2012-06-25	28	25	0	185
A10-0329		Gas-0329	Install Date: 10/21/2010	Natural Gas	803163	443214	2012-05-24	30	43	0	217
A10-0330		Gas-0330	Install Date: 09/03/2009	Natural Gas	1179659	340878	2012-05-31	31	273	0	210
A10-0331		Gas-0331	Install Date: 10/08/2009	Natural Gas	803163	450163	2012-06-26	29	2	0	184
A10-0332		Gas-0332	Install Date: 10/26/2010	Natural Gas	623588	285366	2012-06-25	31	153	0	185
A10-0333		Gas-0333	Install Date: 09/01/2010	Natural Gas	1485766	948947	2012-06-08	30	208	0	202

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A10-0334		Gas-0334	Install Date: 01/01/2011	Natural Gas	818040	390765	2012-06-11	32	0	0	199
A10-0335		Gas-0335	Install Date: 11/17/2011	Natural Gas	1751620	447402	2012-05-30	30	0	0	211
A10-0336		Gas-0336	Install Date: 10/07/2010	Natural Gas	1402506	882533	2012-06-20	29	12	0	190
A10-0337		Gas-0337	Install Date: 10/12/2010	Natural Gas	1402506	866575	2012-06-13	29	0	0	197
A10-0340		Gas-0340	Install Date: 12/02/2010	Natural Gas	319511	194397	2012-06-06	29	38	0	204
A10-0342		Gas-0342	Install Date: 11/19/2010	Natural Gas	890137	645817	2012-06-13	30	58	0	197
A10-0343		Gas-0343	Install Date: 05/29/2011	Natural Gas	641336	448614	2012-05-31	30	66	0	210
A10-0344		Gas-0344	Install Date: 05/19/2011	Natural Gas	1341670	452253	2012-05-31	30	59	0	210
A10-0345		Gas-0345	Install Date: 04/19/2011	Natural Gas	499404	448960	2012-05-31	30	71	0	210
A10-0346		Gas-0346	Install Date: 08/18/2011	Natural Gas	817761	387760	2012-10-18	29	30	0	70
A10-0347		Gas-0347	Install Date: 01/13/2011	Natural Gas	1822951	449668	2012-03-05	3	12	0	297
A10-0348		Gas-0348	Install Date: 03/31/2011	Natural Gas	1581034	969052	2012-06-05	32	197	0	205
A10-0349		Gas-0349	Install Date: 07/12/2010	Natural Gas	645343	506780	2012-06-04	32	85	0	206
A10-0352		Gas-0352	Install Date: 10/06/2009	Natural Gas	302036	207530	2012-06-08	30	136	0	202
A10-0354		Gas-0354	Install Date: 03/14/2011	Natural Gas	1179024	333089	2012-05-31	31	456	0	210
A10-0356		Gas-0356	Install Date: 08/30/2010	Natural Gas	480216	719774	2012-05-30	30	430	0	211
A10-0357		Gas-0357	Install Date: 02/03/2010	Natural Gas	498358	342519	2012-06-04	32	160	0	206
A11-0362		Gas-0362	Install Date: 11/15/2010	Natural Gas	1595082	57976	2012-06-06	33	22	0	204
A11-0363		Gas-0363	Install Date: 10/24/2011	Natural Gas	623952	307037	2012-06-26	29	150	0	184
A11-0365		Gas-0365	Install Date: 06/29/2011	Natural Gas	314644	176516	2012-10-10	30	245	0	78
A11-0367		Gas-0367	Install Date: 08/31/2010	Natural Gas	1014621	677115	2012-06-05	32	48	0	205
A11-0368		Gas-0368	Install Date: 03/02/2011	Natural Gas	406980	5790	2012-06-13	30	0	0	197
A11-0369		Gas-0369	Install Date: 01/11/2011	Natural Gas	1178128	30815	2012-06-05	32	30	0	205
A11-0373		Gas-0373	Install Date: 10/07/2010	Natural Gas	1481561	948241	2012-06-15	30	153	0	195
A11-0374		Gas-0374	Install Date: 12/23/2010	Natural Gas	1195341	486404	2012-05-31	31	1,847	0	210
A11-0375		Gas-0375	Install Date: 09/28/2011	Natural Gas	487848	320280	2012-06-05	32	107	0	205
A11-0379		Gas-0379	Install Date: 07/23/2010	Natural Gas	1401703	947826	2012-05-17	28	9	0	224
A11-0380		Gas-0380	Install Date: 07/01/2011	Natural Gas	1792540	305154	2012-10-03	29	16	0	85
A11-0382		Gas-0382	Install Date: 09/23/2011	Natural Gas	1406994	948121	2012-09-27	31	1,233	0	91
A11-0383		Gas-0383	Install Date: 09/23/2011	Natural Gas	499722	513576	2012-06-04	31	47	0	206
A11-0393		Gas-0393	Install Date: 11/14/2011	Natural Gas	1942050	676107	2012-06-26	28	118	0	184
A11-0394		Gas-0394	Install Date: 08/30/2011	Natural Gas	160859	229467	2012-05-17	28	113	0	224
A11-0395		Gas-0395	Install Date: 09/22/2011	Natural Gas	1452543	948928	2012-05-28	28	106	0	213
A11-0396		Gas-0396	Install Date: 03/21/2011	Natural Gas	154889	221252	2012-06-25	31	17	0	185
A11-0400		Gas-0400	Install Date: 09/17/2011	Natural Gas	493210	230125	2012-06-12	32	56	0	198

Last Reading Dates

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
A11-0406		Gas-0406	Install Date: 03/31/2011	Natural Gas	1734532	276135	2012-05-31	30	49	0	210
A11-0409		Gas-0409	Install Date: 08/24/2011	Natural Gas	1971715	1041741	2012-10-03	28	71	0	85
A11-0410		Gas-0410	Install Date: 10/17/2011	Natural Gas	2009209	1043079	2012-06-19	33	14	0	191
A11-0412		Gas-0412	Install Date: 10/10/2011	Natural Gas	735519	477243	2012-06-06	30	79	0	204
A11-0413		Gas-0413	Install Date: 04/29/2011	Natural Gas	645620	515524	2012-06-05	32	32	0	205
A11-0414		Gas-0414	Install Date: 09/21/2011	Natural Gas	957987	259470	2012-06-01	30	19	0	209
A11-0415		Gas-0415	Install Date: 08/15/2011	Natural Gas	319019	175950	2012-10-05	29	49	0	83
A11-0423		Gas-0423	Install Date: 10/03/2011	Natural Gas	1178214	165142	2012-05-31	31	255	0	210
A11-0435		Gas-0435	Install Date: 07/05/2011	Natural Gas	656019	515650	2012-10-03	29	118	0	85
A11-0436		Gas-0436	Install Date: 08/02/2011	Natural Gas	1890734	511367	2012-10-03	29	38	0	85
A11-0440		Gas-0440	Install Date: 09/24/2011	Natural Gas	524403	449014	2012-10-26	30	102	0	62
A11-0441		Gas-0441	Install Date: 07/15/2011	Natural Gas	623974	307232	2012-10-26	30	111	0	62
A11-0443		Gas-0443	Install Date: 10/11/2012	Natural Gas	644548	497437	2012-05-30	30	142	0	211
A11-0444		Gas-0444	Install Date: 10/11/2012	Natural Gas	1178656	307010	2012-05-31	31	168	0	210
A11-0445		Gas-0445	Install Date: 10/31/2011	Natural Gas	1047766	614115	2012-06-04	32	162	0	206
A11-0447		Gas-0447	Install Date: 08/25/2011	Natural Gas	1441423	880130	2012-10-11	30	35	0	77
A11-0449		Gas-0449	Install Date: 12/28/2011	Natural Gas	1178546	305236	2012-05-31	31	235	0	210
A11-0453		Gas-0453	Install Date: 10/27/2011	Natural Gas	1690376	675916	2012-06-26	28	115	0	184
A11-0455		Gas-0455	Install Date: 08/25/2011	Natural Gas	1733186	519109	2012-10-10	29	56	0	78
A11-0457		Gas-0457	Install Date: 08/17/2011	Natural Gas	645621	515557	2012-10-04	28	37	0	84
A11-0461		Gas-0461	Install Date: 09/30/2011	Natural Gas	1432055	899436	2012-06-21	29	22	0	189
A11-0462		Gas-0462	Install Date: 09/14/2011	Natural Gas	498664	399814	2012-10-11	30	180	0	77
A11-0467		Gas-0467	Install Date: 01/09/2011	Natural Gas	646028	520625	2012-06-05	32	44	0	205
A11-0468		Gas-0468	Install Date: 09/06/2011	Natural Gas	192287	277908	2012-05-31	31	174	0	210
A11-0472		Gas-0472	Install Date: 10/25/2011	Natural Gas	656451	311819	2012-06-04	32	67	0	206
A11-0474		Gas-0474	Install Date: 11/03/2011	Natural Gas	734542	472333	2012-06-06	30	39	0	204
A11-0475		Gas-0475	Install Date: 10/10/2011	Natural Gas	624062	312896	2012-06-26	28	51	0	184
A11-0476		Gas-0476	Install Date: 10/10/2011	Natural Gas	1178527	261349	2012-05-31	31	224	0	210
A11-0477		Gas-0477	Install Date: 10/10/2011	Natural Gas	645323	506525	2012-06-04	32	46	0	206
A11-0496		Gas-0496	Install Date: 09/07/2011	Natural Gas	1737068	645537	2012-06-12	33	0	0	198
A11-0497		Gas-0497	Install Date: 10/27/2011	Natural Gas	1179499	711350	2012-05-31	31	481	0	210
A11-0499		Gas-0499	Install Date: 01/27/2012	Natural Gas	1996937	1046533	2012-06-12	32	59	0	198
A11-0501		Gas-0501	Install Date: 11/29/2011	Natural Gas	1505113	948143	2012-06-13	33	8	0	197
A11-0507		Gas-0507	Install Date: 10/06/2011	Natural Gas	699084	280929	2012-06-21	29	55	0	189
A11-0512		Gas-0512	Install Date: 10/24/2011	Natural Gas	1179605	507576	2012-05-31	31	1,000	0	210

APPENDIX D: Survey Questions

Q1. How many boilers did you have prior to the Efficient Boiler Retrofit Program?

NUMBER OF BOILERS: ________

Q2. How many of these boilers were replaced through the Efficient Boiler Retrofit Program?

NUMBER OF BOILERS: ________

Q3a. What proportion of the overall load is served by the retrofitted heating plant? Please answer in "percent of floor area".

PERCENT OF FLOOR AREA: ______%

Q3b. Which of the following are part of the facility where the new boiler was installed?

Pool
Radiant heating
Baseboard hot water heating
Domestic hot water
Reheat coils in HVAC systems
Air handling unit coils
Other (please specify): ____________

Q4. What elements of this building are not impacted by the retrofit? That is, they burn natural gas themselves, or they have a separate boiler or other source of heat.

Kitchen
Domestic hot water
Roof top unit (gas fired)
Other (please specify): ____________

Q5. Which of the following best describes your retrofit?

Boiler replacement only
Boiler replacement plus enhanced controls
Boiler Replacement plus other plant upgrades such as piping and distribution update (please specify): ____________

Q6. Were any other energy management measures relating to fuel consumption implemented at the same time or prior to the boiler retrofit? READ LIST

Window replacement
Door replacement
Installing additional insulation
Redesign of HVAC system (fan coils, air handling units)
Zone isolation
Heat recovery
Direct digital control
Other (please specify): ____________

Q7. Have you noticed a change in maintenance requirements or expenditures for the boiler plant following the retrofit?

Yes, increased
Yes, decreased
No change
DON'T KNOW

Q8. Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied", how satisfied are you with the overall service provided by FortisBC?

Q9. Using a scale from 1 to 10 where 1 is 'not at all satisfied' and 10 is 'very satisfied', how satisfied are you with FortisBC's Efficient Boiler program overall?

Q10. Why did you give a rating of [bring in response to question above]_______________?

Q11. How satisfied are you with each of the following aspects of the Efficient Boiler program?
Ease of obtaining information on the program
Ease of completing the application form/program requirements
Program deadlines
Speed of receiving the rebate
FortisBC staff who took your order request and scheduled your work

Q12. In absence of the rebate, would you have installed a standard boiler or a high efficiency boiler?
Standard
High Efficiency
No change/Nothing
Don't know

Q13. Why? What would have been the biggest incentive / barrier to completing the retrofit?

Q14. FortisBC would like to attach your responses to these questions to your account in order more fully understand the impact of the retrofit to your overall usage. Your responses to these questions will be used only for this purpose and all your information including your answers to these questions will remain confidential. Do I have your permission to provide FortisBC with your responses to my questions? IF 'YES', FILL OUT THE FOLLOWING, IF 'NO' SKIP TO Q13

Q15. Finally, FortisBC may wish to complete follow up research with you regarding this program. Do we have your permission to contact you again? Please use the blank space to write your answers.

APPENDIX E: Excluded Sites

Group	Site	Category	Comment
Group2	A05-0143	No Post Retrofit Data	no longer customer
Group2	A05-0025	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0097	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0118	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0139	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0141	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0142	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0158	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0166	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0167	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A05-0233	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A10-0278	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A10-0283	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A11-0409	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A11-0410	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A11-0499	Insuff Pre Retrofit Data	installed boiler soon after they became customer with FortisBC
Group2	A10-0335	0 consumption	excluded
Group2	A11-0496	0 consumption	excluded
Group2	A05-0175	0 consumption	excluded
Group1	A05-0009	Excluded in Year 1	
Group2	A10-271	duplication of A11-0379 (MURB)	
Group2	A11-518	duplication of A05-0090 (School)	
Group2	A05-0209	Multiple installation 2009/2010/2011	
Group2	A10-0317	Regression model	drastic change in consumption after retrofit (too significant tobe to be savings!)
Group2	A11-0368	Regression model	0 consumption
Group2	A05-0208	No Post Retrofit Data	to be included in Year 3

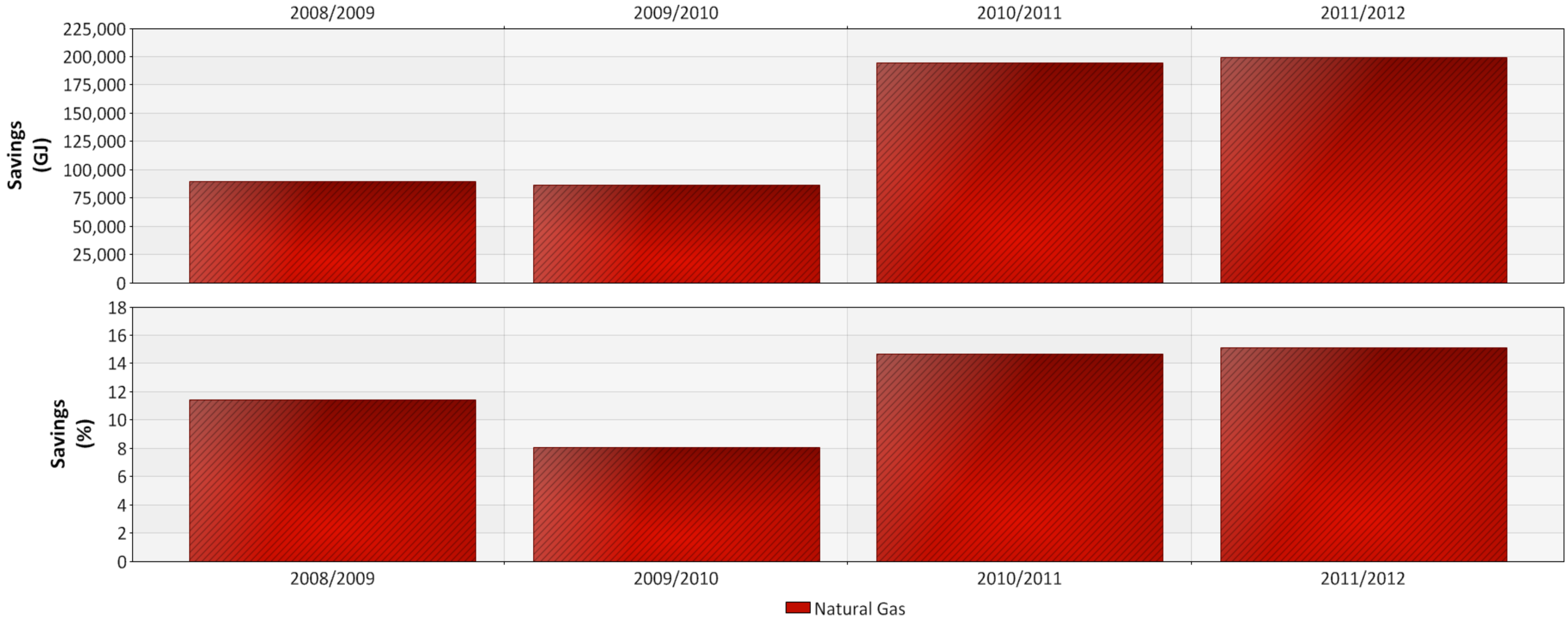
Group	Site	Category	Comment
Group2	A10-0266	No Post Retrofit Data	to be included in Year 3
Group2	A11-0443	No Post Retrofit Data	to be included in Year 3
Group2	A11-0444	No Post Retrofit Data	to be included in Year 3
Group2	A10-0283	Insuff Post Retrofit Data	to be included in Year 3
Group2	A10-0297	Insuff Post Retrofit Data	to be included in Year 3
Group2	A10-0307	Insuff Post Retrofit Data	to be included in Year 3
Group2	A10-0335	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0363	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0375	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0383	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0393	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0394	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0395	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0400	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0410	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0412	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0414	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0423	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0445	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0449	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0453	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0461	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0468	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0472	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0474	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0475	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0476	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0477	Insuff Post Retrofit Data	to be included in Year 3

Group	Site	Category	Comment
Group2	A11-0497	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0499	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0501	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0507	Insuff Post Retrofit Data	to be included in Year 3
Group2	A11-0512	Insuff Post Retrofit Data	to be included in Year 3
Group2	A10-0333	Insuff Post Retrofit Data	to be included in Year 3
Group2	A05-0038	NC Sites	
Group2	A05-0091	NC Sites	
Group2	A05-0162	NC Sites	
Group1	A05-0084	School closed as such excluded	
Group1	A05-0024	Greenhouse with floor area change as such excluded	
Group1	A05-0163	Park Royal - site with significant changes as such excluded	
Group1	A05-0169	Greenhouse with floor area change as such excluded	
Group1	A05-0184	Statistiacal Outlier from 2011 study	
Group1	A10-0253	Statistiacal Outlier from 2011 study	
Group2	A10-0334	Meter failed as such excluded from study	
Group2	A05-0001	EA Games - Building Extension	

APPENDIX F: Annual Energy Savings

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**



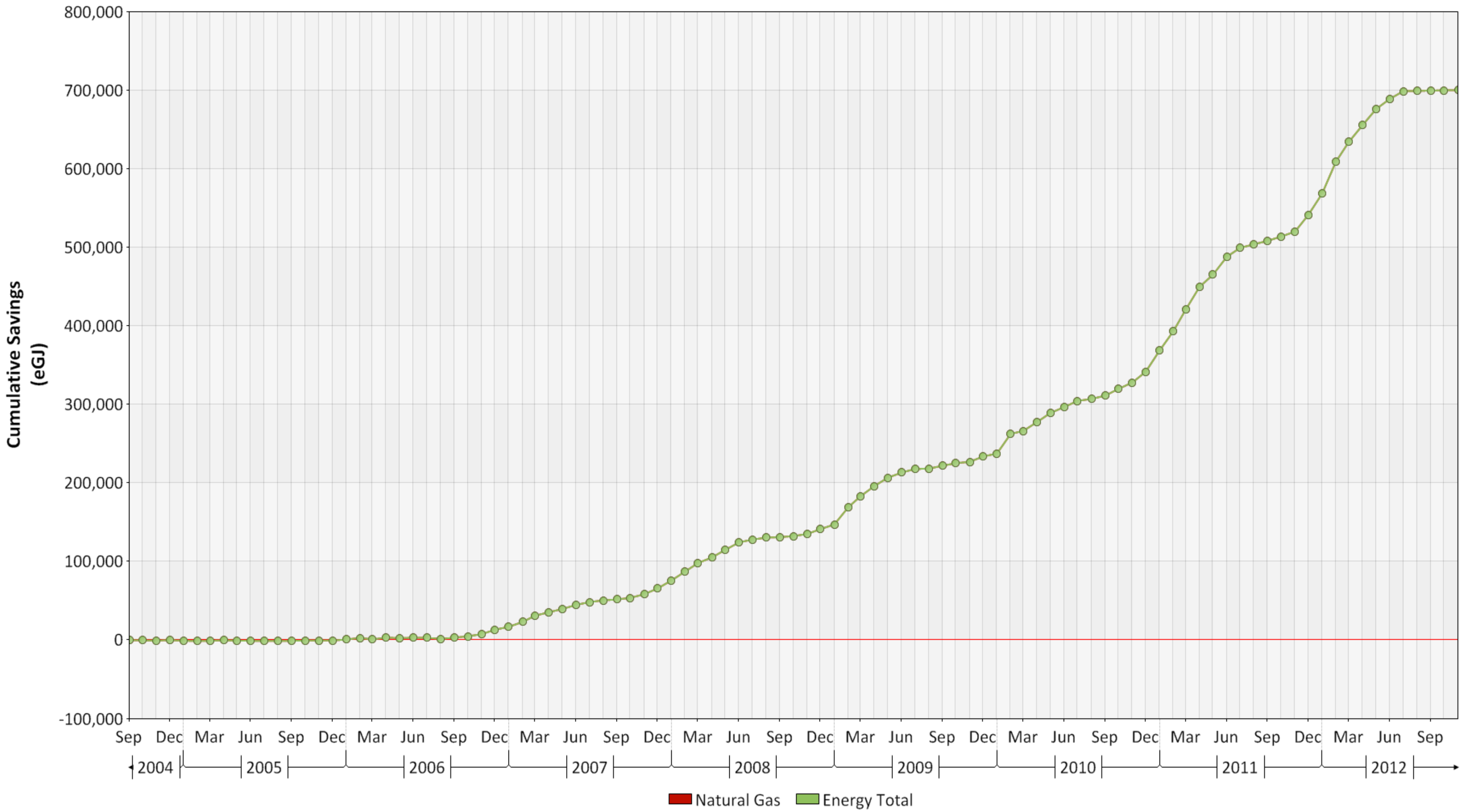
Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2008/2009	695,969	785,905	89,936	11
2009/2010	983,838	1,070,607	86,769	8
2010/2011	1,129,100	1,323,961	194,861	15
2011/2012	1,118,794	1,318,300	199,506	15
Total:	**3,927,700**	**4,498,773**	**571,073**	**13**

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

APPENDIX G: CUSUM – Project

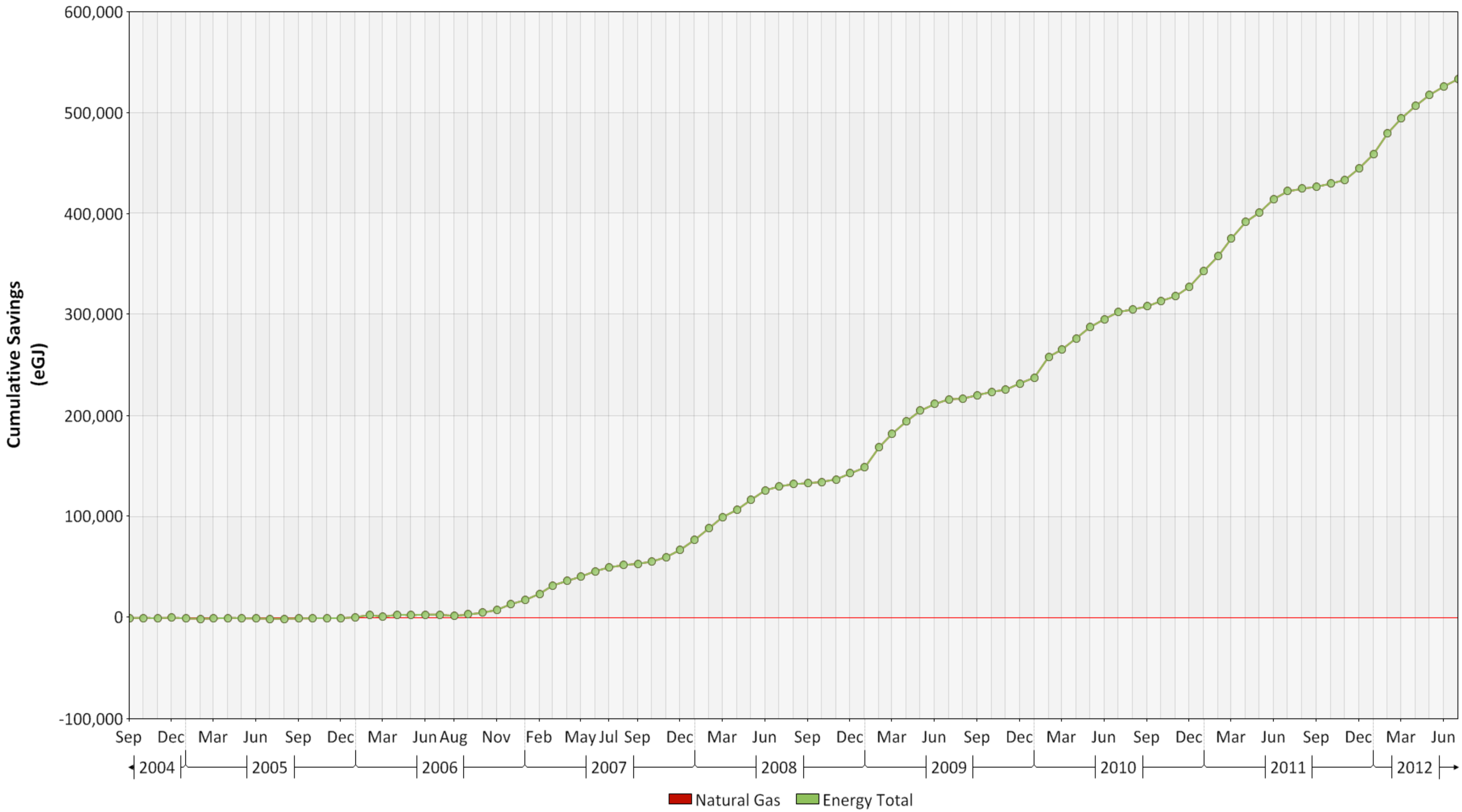
CUSUM: Grouping

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**



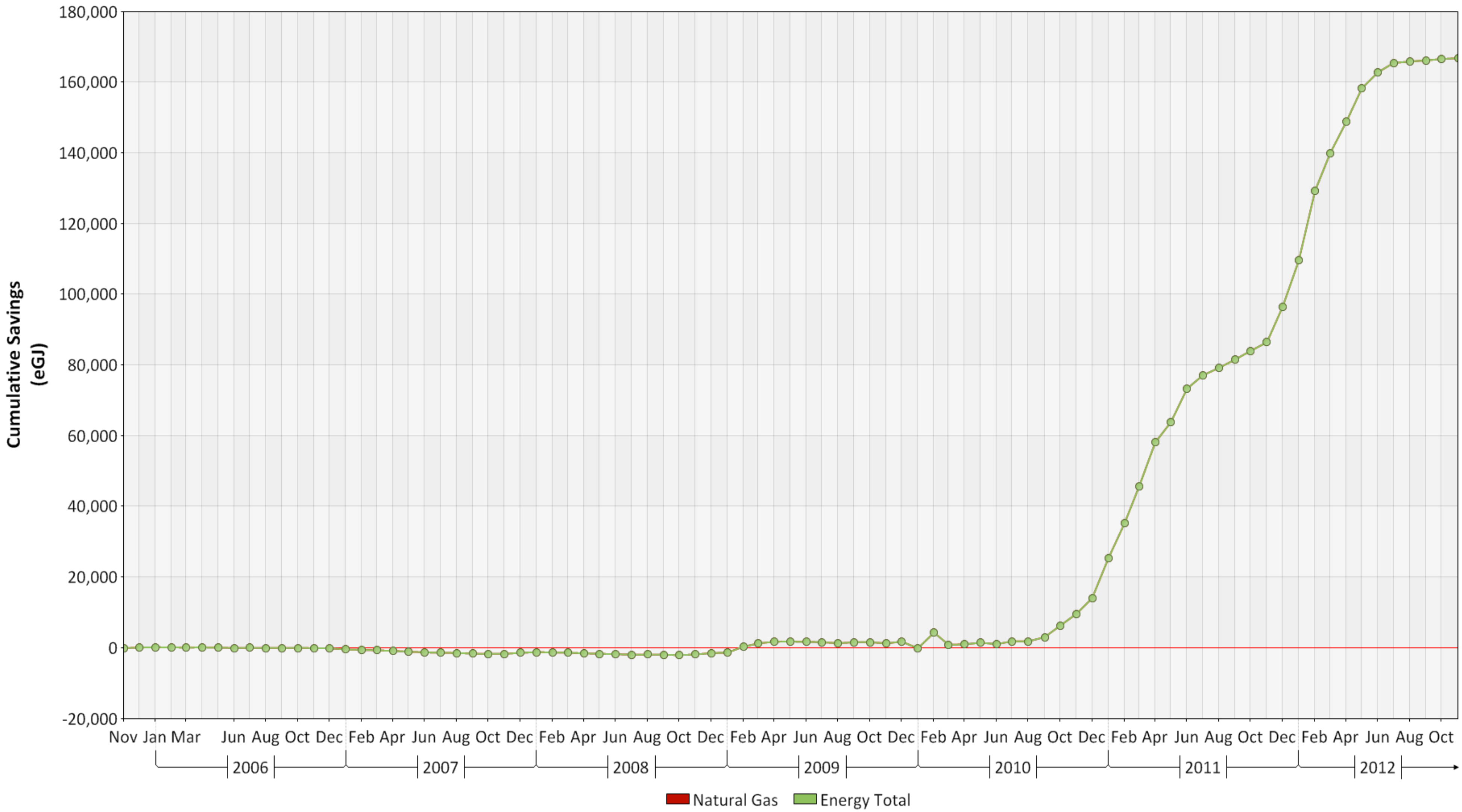
CUSUM: Grouping

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project By Group1, Group2 and Outliers**
Grouping: **Group 1**



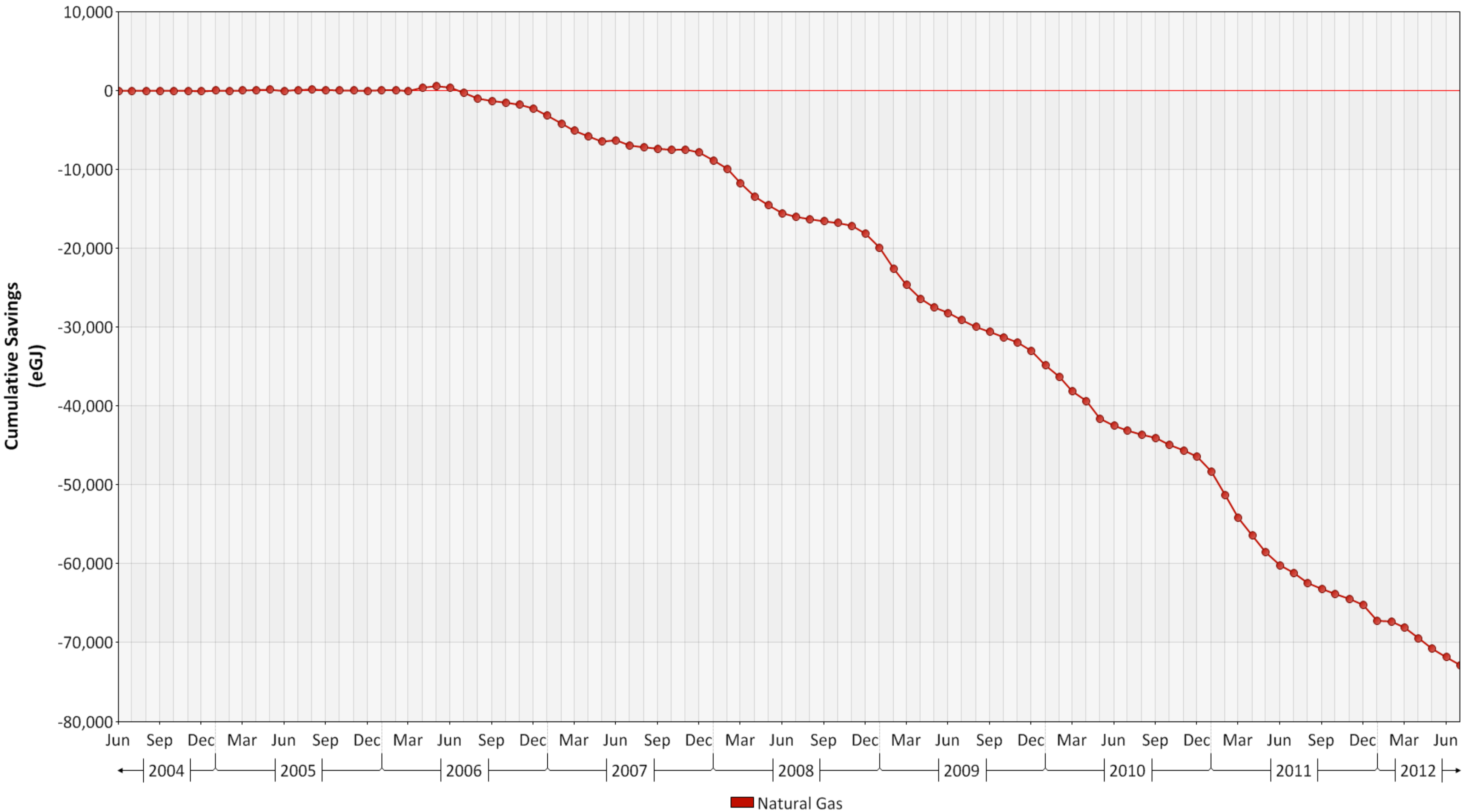
CUSUM: Grouping

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project By Group1, Group2 and Outliers**
Grouping: **Group 2**



CUSUM: Grouping

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project By Group1, Group2 and Outliers**
Grouping: **Outlier**



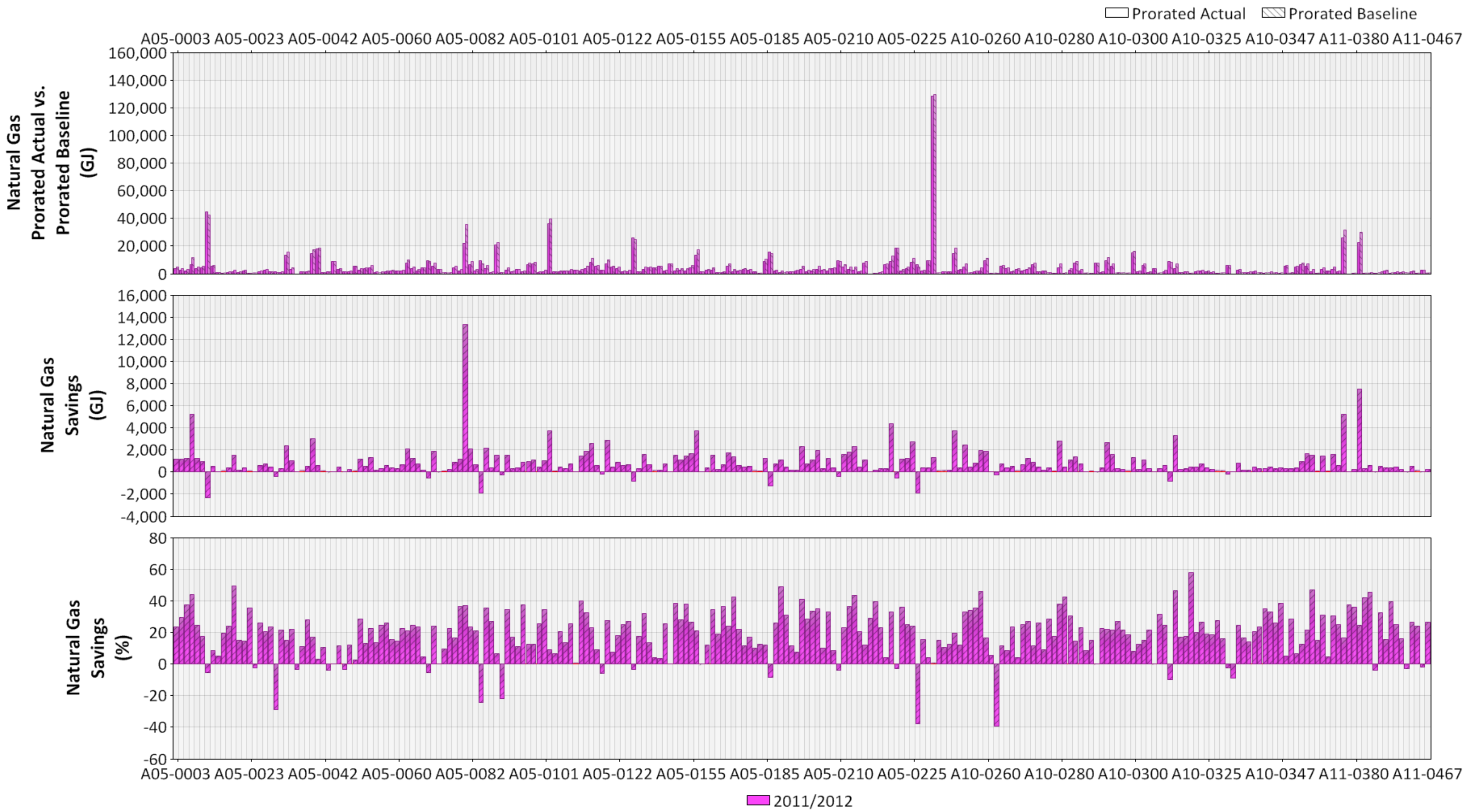
APPENDIX H: CUSUM – Site

Due to large file size, this Appendix is provided as a separate file

APPENDIX I: Savings By Year By Site

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**



[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site		Year[1]	Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description		GJ	GJ	Abs. GJ	%
A05-0003	Premise : 406662	2011/2012	3,927	5,137	1,211	24
A05-0004	Premise : 254236	2011/2012	2,733	3,894	1,161	30
A05-0005	Premise : 610023	2011/2012	2,135	3,424	1,288	38
A05-0006	Premise : 704208	2011/2012	6,632	11,893	5,261	44
A05-0007	Premise : 51073	2011/2012	3,927	5,211	1,284	25
A05-0008	Premise : 280132	2011/2012	4,769	5,783	1,015	18
A05-0010	Premise : 266683	2011/2012	45,140	42,849	-2,291	-5
A05-0011	Premise : 468596	2011/2012	5,645	6,191	545	9
A05-0012	Premise : 387051	2011/2012	1,311	1,387	76	5
A05-0015	Premise : 472188	2011/2012	686	857	171	20
A05-0017	Premise : 684089	2011/2012	1,302	1,713	411	24
A05-0019	Premise : 256597	2011/2012	1,550	3,075	1,525	50
A05-0021	Premise : 399773	2011/2012	1,272	1,504	232	15
A05-0022	Premise : 311848	2011/2012	2,439	2,865	427	15
A05-0023	Premise : 35729	2011/2012	288	449	160	36
A05-0026	Premise : 423077	2011/2012	901	883	-18	-2
A05-0027	Premise : 525328	2011/2012	1,757	2,381	624	26
A05-0028	Premise : 545094	2011/2012	2,931	3,688	757	21
A05-0029	Premise : 617167	2011/2012	1,516	1,991	475	24
A05-0030	Premise : 290739	2011/2012	1,644	1,276	-368	-29
A05-0031	Premise : 318638	2011/2012	1,373	1,750	377	22
A05-0032	Premise : 612048	2011/2012	13,653	16,065	2,412	15
A05-0033	Premise : 310861	2011/2012	3,618	4,638	1,020	22
A05-0034	Premise : 522033	2011/2012	123	119	-4	-3
A05-0035	Premise : 236764	2011/2012	1,448	1,633	186	11
A05-0037	Premise : 313476	2011/2012	1,477	2,052	575	28
A05-0038	Premise : 539038	2011/2012	14,660	17,673	3,012	17
A05-0040	Premise : 811250	2011/2012	18,266	18,885	619	3
A05-0042	Premise : 308141	2011/2012	1,251	1,405	154	11

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site		Year[1]	Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description		GJ	GJ	Abs. GJ	%
A05-0044	Premise : 388193	2011/2012	1,522	1,464	-58	-4
A05-0045	Premise : 317893	2011/2012	9,343	9,342	-1	0
A05-0047	Premise : 390048	2011/2012	3,577	4,048	470	12
A05-0048	Premise : 403864	2011/2012	1,932	1,874	-58	-3
A05-0050	Premise : 360590	2011/2012	1,754	1,996	242	12
A05-0051	Premise : 409296	2011/2012	5,539	5,700	161	3
A05-0052	Premise : 304098	2011/2012	2,982	4,176	1,193	29
A05-0053	Premise : 282017	2011/2012	3,781	4,359	578	13
A05-0055	Premise : 332435	2011/2012	4,615	5,983	1,368	23
A05-0056	Premise : 332417	2011/2012	1,294	1,504	210	14
A05-0057	Premise : 332425	2011/2012	1,102	1,467	365	25
A05-0058	Premise : 332349	2011/2012	1,823	2,471	648	26
A05-0059	Premise : 332382	2011/2012	2,331	2,771	440	16
A05-0060	Premise : 332383	2011/2012	2,080	2,445	365	15
A05-0061	Premise : 332384	2011/2012	2,289	2,952	664	22
A05-0062	Premise : 522363	2011/2012	7,921	10,058	2,136	21
A05-0065	Premise : 275850	2011/2012	3,920	5,207	1,288	25
A05-0066	Premise : 30724	2011/2012	2,471	3,246	775	24
A05-0068	Premise : 307235	2011/2012	4,318	4,523	205	5
A05-0069	Premise : 414759	2011/2012	9,887	9,380	-506	-5
A05-0070	Premise : 608173	2011/2012	5,874	7,764	1,890	24
A05-0072	Premise : 248451	2011/2012	3,237	3,222	-15	0
A05-0075	Premise : 644376	2011/2012	1,073	1,186	113	10
A05-0077	Premise : 64492	2011/2012	976	1,265	289	23
A05-0079	Premise : 606229	2011/2012	4,645	5,574	929	17
A05-0080	Premise : 256346	2011/2012	2,051	3,241	1,190	37
A05-0081	Premise : 286361	2011/2012	22,423	35,776	13,353	37
A05-0082	Premise : 285146	2011/2012	6,901	9,034	2,133	24
A05-0085	Premise : 525780	2011/2012	2,535	3,224	690	21
A05-0086	Premise : 191021	2011/2012	9,460	7,618	-1,842	-24

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site			Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description	Year[1]	GJ	GJ	Abs. GJ	%
A05-0087	Premise : 779272	2011/2012	3,922	6,099	2,177	36
A05-0089	Premise : 45157	2011/2012	1,162	1,600	438	27
A05-0090	Premise : 508368	2011/2012	21,316	22,838	1,522	7
A05-0091	Premise : 984590	2011/2012	1,301	1,069	-232	-22
A05-0093	Premise : 285521	2011/2012	2,846	4,370	1,524	35
A05-0094	Premise : 508110	2011/2012	1,690	2,040	350	17
A05-0095	Premise : 160979	2011/2012	3,260	3,672	412	11
A05-0096	Premise : 51072	2011/2012	1,535	2,463	928	38
A05-0098	Premise : 782766	2011/2012	6,853	7,843	990	13
A05-0099	Premise : 652994	2011/2012	7,621	8,739	1,118	13
A05-0100	Premise : 771423	2011/2012	1,331	1,790	459	26
A05-0101	Premise : 266117	2011/2012	1,973	3,009	1,036	34
A05-0102	Premise : 702112	2011/2012	36,280	40,039	3,759	9
A05-0103	Premise : 449169	2011/2012	1,829	1,964	135	7
A05-0104	Premise : 483716	2011/2012	1,922	2,429	506	21
A05-0105	Premise : 266076	2011/2012	2,188	2,539	351	14
A05-0106	Premise : 265806	2011/2012	2,343	3,144	801	25
A05-0109	Premise : 313159	2011/2012	2,708	2,733	25	1
A05-0110	Premise : 721346	2011/2012	2,160	3,607	1,447	40
A05-0112	Premise : 505743	2011/2012	3,971	5,877	1,906	32
A05-0114	Premise : 290590	2011/2012	8,703	11,330	2,627	23
A05-0115	Premise : 257082	2011/2012	5,689	6,282	594	9
A05-0116	Premise : 737983	2011/2012	2,801	2,645	-155	-6
A05-0119	Premise : 279229	2011/2012	7,585	10,487	2,902	28
A05-0120	Premise : 480833	2011/2012	5,253	5,704	451	8
A05-0122	Premise : 330288	2011/2012	4,163	5,089	927	18
A05-0123	Premise : 473191	2011/2012	1,913	2,552	640	25
A05-0125	Premise : 309195	2011/2012	1,883	2,585	702	27
A05-0131	Premise : 257372	2011/2012	25,957	25,167	-790	-3
A05-0132	Premise : 688856	2011/2012	1,438	1,746	308	18

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site			Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description	Year[1]	GJ	GJ	Abs. GJ	%
A05-0133	Premise : 785675	2011/2012	3,471	5,100	1,629	32
A05-0134	Premise : 541514	2011/2012	4,521	5,228	707	14
A05-0136	Premise : 299702	2011/2012	4,432	4,629	197	4
A05-0137	Premise : 478417	2011/2012	5,437	5,653	217	4
A05-0138	Premise : 420870	2011/2012	2,185	2,937	752	26
A05-0140	Premise : 365653	2011/2012	7,165	7,198	32	0
A05-0144	Premise : 496208	2011/2012	2,404	3,928	1,523	39
A05-0150	Premise : 295067	2011/2012	2,836	3,963	1,127	28
A05-0154	Premise : 515881	2011/2012	2,367	3,819	1,452	38
A05-0155	Premise : 536113	2011/2012	4,678	6,398	1,720	27
A05-0156	Premise : 302558	2011/2012	13,721	17,453	3,732	21
A05-0159	Premise : 423566	2011/2012	1,488	1,478	-10	-1
A05-0162	Premise : 986989	2011/2012	2,955	3,363	407	12
A05-0171	Premise : 197335	2011/2012	2,980	4,561	1,580	35
A05-0173	Premise : 14291	2011/2012	1,143	1,411	268	19
A05-0174	Premise : 10891	2011/2012	1,147	1,813	666	37
A05-0176	Premise : 510439	2011/2012	5,581	7,352	1,771	24
A05-0177	Premise : 307218	2011/2012	1,859	3,254	1,395	43
A05-0178	Premise : 161485	2011/2012	2,059	2,654	595	22
A05-0180	Premise : 304568	2011/2012	3,692	4,194	502	12
A05-0181	Premise : 490831	2011/2012	2,830	3,417	587	17
A05-0182	Premise : 478440	2011/2012	1,600	1,781	182	10
A05-0183	Premise : 482862	2011/2012	687	788	100	13
A05-0185	Premise : 399907	2011/2012	9,337	10,637	1,300	12
A05-0188	Premise : 948964	2011/2012	16,055	14,859	-1,196	-8
A05-0189	Premise : 562819	2011/2012	2,210	2,992	782	26
A05-0190	Premise : 462258	2011/2012	1,177	2,309	1,132	49
A05-0191	Premise : 285143	2011/2012	1,015	1,478	463	31
A05-0192	Premise : 267973	2011/2012	1,692	1,919	227	12
A05-0193	Premise : 309516	2011/2012	2,372	2,576	204	8

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site		Year[1]	Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description		GJ	GJ	Abs. GJ	%
A05-0195	Premise : 726355	2011/2012	3,355	5,718	2,363	41
A05-0196	Premise : 325654	2011/2012	1,977	2,766	789	29
A05-0197	Premise : 326188	2011/2012	2,193	3,312	1,119	34
A05-0198	Premise : 467934	2011/2012	3,618	5,591	1,974	35
A05-0199	Premise : 565898	2011/2012	2,824	3,152	328	10
A05-0201	Premise : 464925	2011/2012	2,473	3,714	1,241	33
A05-0204	Premise : 311832	2011/2012	4,082	4,474	392	9
A05-0210	Premise : 541687	2011/2012	9,683	9,323	-360	-4
A05-0211	Premise : 295211	2011/2012	5,346	6,960	1,614	23
A05-0212	Premise : 675822	2011/2012	3,186	5,019	1,833	37
A05-0213	Premise : 675784	2011/2012	3,022	5,364	2,342	44
A05-0214	Premise : 676296	2011/2012	1,768	2,235	466	21
A05-0216	Premise : 428189	2011/2012	8,023	9,145	1,122	12
A05-0217	Premise : 67113	2011/2012	65	92	27	29
A05-0218	Premise : 11827	2011/2012	345	573	227	40
A05-0219	Premise : 288862	2011/2012	1,180	1,537	357	23
A05-0220	Premise : 257203	2011/2012	6,836	7,148	312	4
A05-0221	Premise : 460627	2011/2012	8,859	13,244	4,385	33
A05-0222	Premise : 264610	2011/2012	19,009	18,518	-491	-3
A05-0223	Premise : 288395	2011/2012	2,170	3,397	1,227	36
A05-0224	Premise : 675957	2011/2012	3,724	4,993	1,269	25
A05-0225	Premise : 321898	2011/2012	8,609	11,370	2,761	24
A05-0227	Premise : 645733	2011/2012	6,719	4,884	-1,835	-38
A05-0228	Premise : 285568	2011/2012	2,314	2,749	435	16
A05-0229	Premise : 414476	2011/2012	9,478	9,911	433	4
A05-0230	Premise : 331194	2011/2012	128,696	130,032	1,336	1
A05-0235	Premise : 787691	2011/2012	928	1,096	168	15
A05-0237	Premise : 177505	2011/2012	1,630	1,824	194	11
A05-0238	Premise : 458982	2011/2012	1,631	1,865	233	13
A10-0247	Premise : 703441	2011/2012	15,075	18,822	3,747	20

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site			Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description	Year[1]	GJ	GJ	Abs. GJ	%
A10-0251	Premise : 306259	2011/2012	3,085	3,517	432	12
A10-0254	Premise : 523253	2011/2012	4,993	7,461	2,468	33
A10-0256	Premise : 466700	2011/2012	907	1,375	468	34
A10-0257	Premise : 502998	2011/2012	1,474	2,291	817	36
A10-0258	Premise : 316423	2011/2012	2,325	4,297	1,972	46
A10-0260	Premise : 496391	2011/2012	9,707	11,628	1,921	17
A10-0261	Premise : 543472	2011/2012	523	556	33	6
A10-0262	Premise : 298670	2011/2012	734	529	-206	-39
A10-0263	Premise : 276519	2011/2012	5,661	6,414	753	12
A10-0264	Premise : 306576	2011/2012	3,922	4,299	377	9
A10-0265	Premise : 306231	2011/2012	1,898	2,480	582	23
A10-0267	Premise : 505806	2011/2012	3,657	3,822	165	4
A10-0268	Premise : 768886	2011/2012	2,161	2,889	728	25
A10-0269	Premise : 481798	2011/2012	3,455	4,749	1,295	27
A10-0270	Premise : 285146	2011/2012	6,901	7,799	898	12
A10-0274	Premise : 303042	2011/2012	1,457	1,973	516	26
A10-0275	Premise : 311850	2011/2012	2,283	2,515	232	9
A10-0276	Premise : 490345	2011/2012	1,015	1,420	405	29
A10-0279	Premise : 498769	2011/2012	539	656	117	18
A10-0280	Premise : 323282	2011/2012	4,581	7,411	2,830	38
A10-0281	Premise : 403254	2011/2012	628	1,092	464	43
A10-0282	Premise : 472226	2011/2012	2,617	3,773	1,157	31
A10-0284	Premise : 948068	2011/2012	7,902	9,289	1,387	15
A10-0285	Premise : 310542	2011/2012	2,535	3,307	772	23
A10-0286	Premise : 366396	2011/2012	784	859	75	9
A10-0287	Premise : 312777	2011/2012	560	660	100	15
A10-0289	Premise : 778507	2011/2012	7,826	7,796	-30	0
A10-0290	Premise : 891332	2011/2012	1,391	1,795	405	23
A10-0291	Premise : 670678	2011/2012	9,502	12,179	2,677	22
A10-0292	Premise : 372456	2011/2012	5,736	7,349	1,613	22

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site		Year[1]	Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description		GJ	GJ	Abs. GJ	%
A10-0295	Premise : 472257	2011/2012	925	1,269	344	27
A10-0298	Premise : 462683	2011/2012	861	1,098	237	22
A10-0299	Premise : 383693	2011/2012	768	946	178	19
A10-0300	Premise : 12121	2011/2012	15,348	16,721	1,373	8
A10-0301	Premise : 307203	2011/2012	1,862	2,132	270	13
A10-0303	Premise : 282373	2011/2012	6,085	7,179	1,094	15
A10-0304	Premise : 282312	2011/2012	1,290	1,650	360	22
A10-0305	Premise : 424701	2011/2012	3,885	3,872	-13	0
A10-0309	Premise : 781658	2011/2012	759	1,109	350	32
A10-0312	Premise : 293421	2011/2012	1,962	2,604	643	25
A10-0315	Premise : 537091	2011/2012	9,076	8,294	-783	-9
A10-0316	Premise : 33345	2011/2012	3,850	7,204	3,354	47
A10-0319	Premise : 719214	2011/2012	1,161	1,405	244	17
A10-0321	Premise : 907989	2011/2012	1,506	1,834	328	18
A10-0322	Premise : 258537	2011/2012	333	790	457	58
A10-0323	Premise : 614380	2011/2012	1,969	2,468	499	20
A10-0324	Premise : 649083	2011/2012	2,023	2,767	743	27
A10-0325	Premise : 281329	2011/2012	1,828	2,262	434	19
A10-0326	Premise : 272779	2011/2012	1,344	1,650	306	19
A10-0327	Premise : 543518	2011/2012	486	673	187	28
A10-0329	Premise : 443214	2011/2012	902	1,078	176	16
A10-0330	Premise : 340878	2011/2012	6,152	6,011	-141	-2
A10-0331	Premise : 450163	2011/2012	50	46	-4	-9
A10-0332	Premise : 285366	2011/2012	2,603	3,448	845	25
A10-0337	Premise : 866575	2011/2012	1,125	1,351	226	17
A10-0340	Premise : 194397	2011/2012	1,288	1,499	211	14
A10-0342	Premise : 645817	2011/2012	1,752	2,211	459	21
A10-0343	Premise : 448614	2011/2012	1,072	1,408	337	24
A10-0344	Premise : 452253	2011/2012	665	1,027	362	35
A10-0345	Premise : 448960	2011/2012	1,004	1,500	496	33

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site			Natural Gas			
Name	Description	Year[1]	Prorated Actual GJ	Prorated Baseline GJ	Savings Abs. GJ	Savings %
A10-0346	Premise : 387760	2011/2012	868	1,179	311	26
A10-0347	Premise : 449668	2011/2012	663	1,084	421	39
A10-0348	Premise : 969052	2011/2012	5,931	6,275	344	5
A10-0349	Premise : 506780	2011/2012	850	1,191	341	29
A10-0352	Premise : 207530	2011/2012	5,239	5,616	377	7
A10-0354	Premise : 333089	2011/2012	6,709	7,703	994	13
A10-0356	Premise : 719774	2011/2012	5,951	7,614	1,662	22
A10-0357	Premise : 342519	2011/2012	1,736	3,277	1,541	47
A11-0362	Premise : 57976	2011/2012	633	746	112	15
A11-0365	Premise : 176516	2011/2012	3,218	4,667	1,449	31
A11-0367	Premise : 677115	2011/2012	2,133	2,244	111	5
A11-0369	Premise : 30815	2011/2012	3,684	5,321	1,638	31
A11-0373	Premise : 948241	2011/2012	1,864	2,497	633	25
A11-0374	Premise : 486404	2011/2012	26,449	31,681	5,232	17
A11-0379	Premise : 947826	2011/2012	108	173	65	38
A11-0380	Premise : 305154	2011/2012	491	767	276	36
A11-0382	Premise : 948121	2011/2012	22,850	30,394	7,544	25
A11-0396	Premise : 221252	2011/2012	480	831	351	42
A11-0406	Premise : 276135	2011/2012	759	1,394	636	46
A11-0413	Premise : 515524	2011/2012	632	611	-21	-3
A11-0415	Premise : 175950	2011/2012	1,084	1,609	525	33
A11-0435	Premise : 515650	2011/2012	2,288	2,723	434	16
A11-0436	Premise : 511367	2011/2012	639	1,062	422	40
A11-0440	Premise : 449014	2011/2012	1,412	1,893	481	25
A11-0441	Premise : 307232	2011/2012	1,321	1,577	256	16
A11-0447	Premise : 880130	2011/2012	1,009	981	-28	-3
A11-0455	Premise : 519109	2011/2012	1,608	2,186	578	26
A11-0457	Premise : 515557	2011/2012	578	764	186	24
A11-0462	Premise : 399814	2011/2012	2,658	2,616	-42	-2
A11-0467	Premise : 520625	2011/2012	716	974	258	26

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

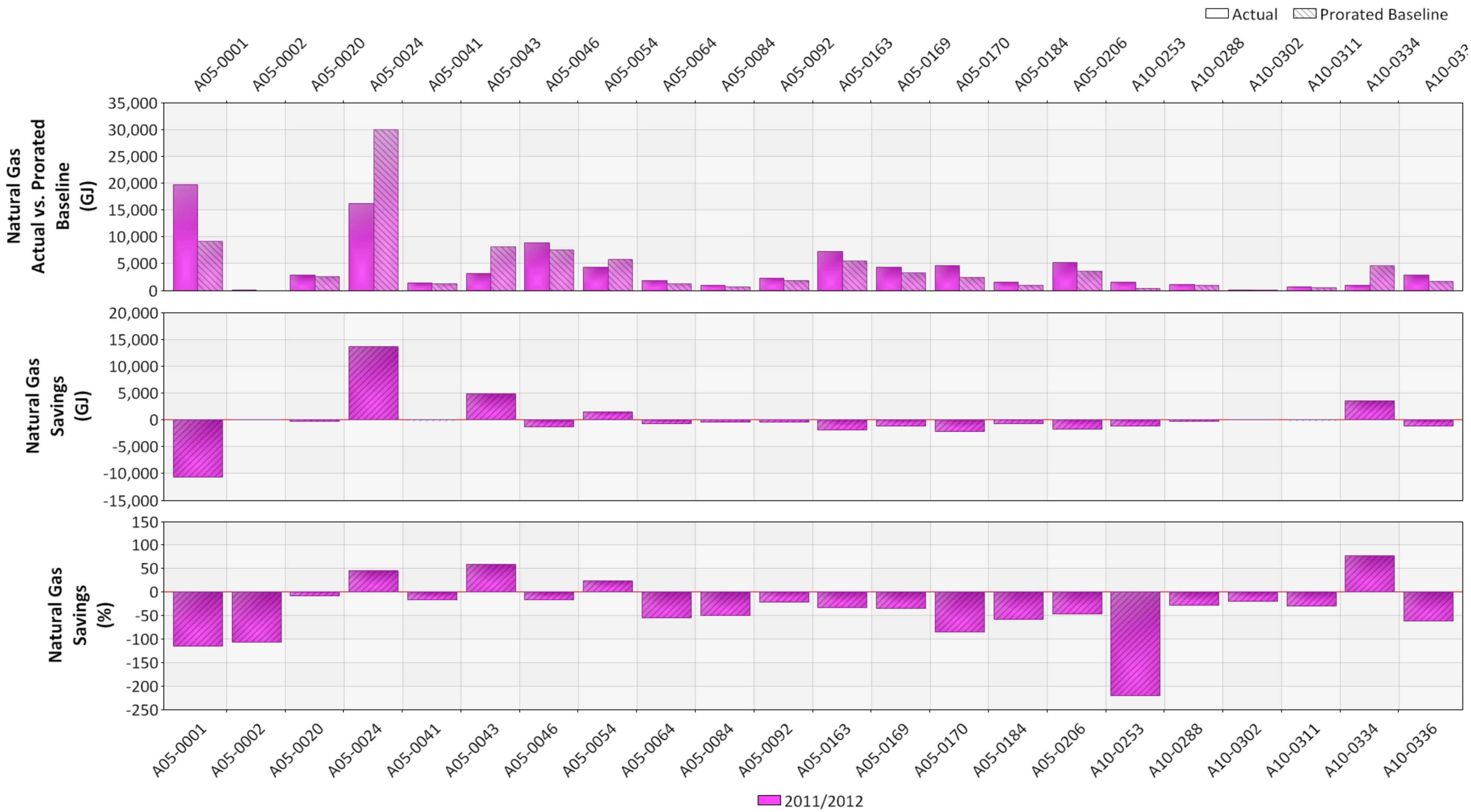
Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Group 1 and Group 2**

Site		Year[1]	Natural Gas			
			Prorated Actual	Prorated Baseline	Savings	
Name	Description		GJ	GJ	Abs. GJ	%
Total:			1,118,794	1,318,300	199,506	15

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Outlier**



[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Site By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project Without Excluded Sites and Outliers**
Grouping: **Outlier**

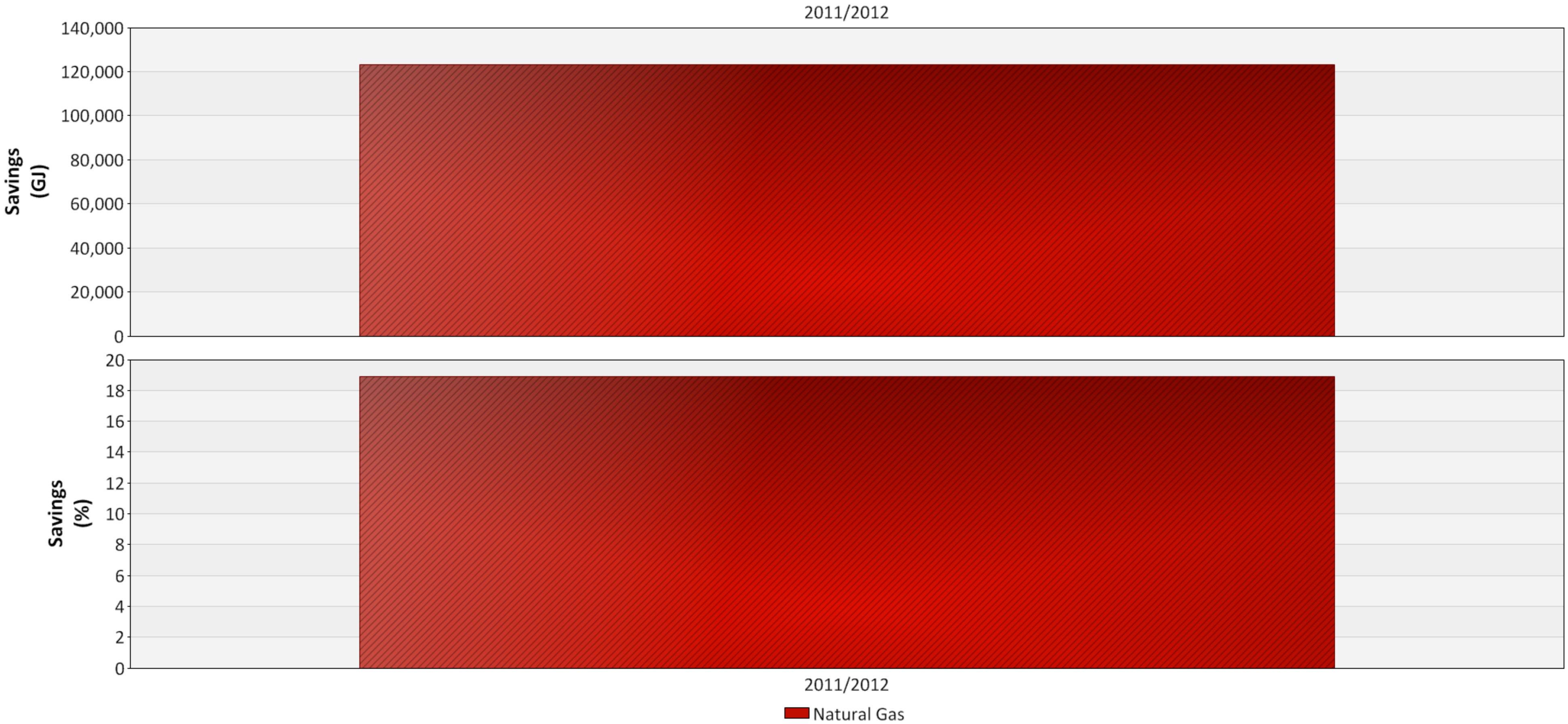
Site			Natural Gas			
Name	Description	Year[1]	Actual GJ	Prorated Baseline GJ	Savings Abs. GJ	Savings %
A05-0001	Premise : 290710	2011/2012	19,704	9,163	-10,541	-115
A05-0002	Premise : 706561	2011/2012	102	50	-52	-105
A05-0020	Premise : 413028	2011/2012	2,861	2,647	-215	-8
A05-0024	Premise : 705498	2011/2012	16,281	29,956	13,675	46
A05-0041	Premise : 308349	2011/2012	1,523	1,314	-208	-16
A05-0043	Premise : 670431	2011/2012	3,271	8,173	4,902	60
A05-0046	Premise : 311883	2011/2012	8,863	7,624	-1,239	-16
A05-0054	Premise : 332426	2011/2012	4,393	5,873	1,480	25
A05-0064	Premise : 525699	2011/2012	1,957	1,271	-687	-54
A05-0084	Premise : 645039	2011/2012	1,034	690	-344	-50
A05-0092	Premise : 497490	2011/2012	2,351	1,958	-393	-20
A05-0163	Premise : 605934	2011/2012	7,299	5,522	-1,776	-32
A05-0169	Premise : 272939	2011/2012	4,449	3,313	-1,136	-34
A05-0170	Premise : 82262	2011/2012	4,641	2,518	-2,123	-84
A05-0184	Premise : 325339	2011/2012	1,589	1,011	-578	-57
A05-0206	Premise : 345442	2011/2012	5,285	3,609	-1,675	-46
A10-0253	Premise : 58610	2011/2012	1,612	505	-1,107	-219
A10-0288	Premise : 317120	2011/2012	1,224	964	-260	-27
A10-0302	Premise : 280658	2011/2012	151	127	-24	-19
A10-0311	Premise : 948177	2011/2012	667	514	-152	-30
A10-0334	Premise : 390765	2011/2012	1,018	4,644	3,626	78
A10-0336	Premise : 882533	2011/2012	2,870	1,788	-1,081	-60
Total:			**93,144**	**93,235**	**91**	**0**

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

APPENDIX J: Savings By Year By Grouping 2011/12

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **MURB**

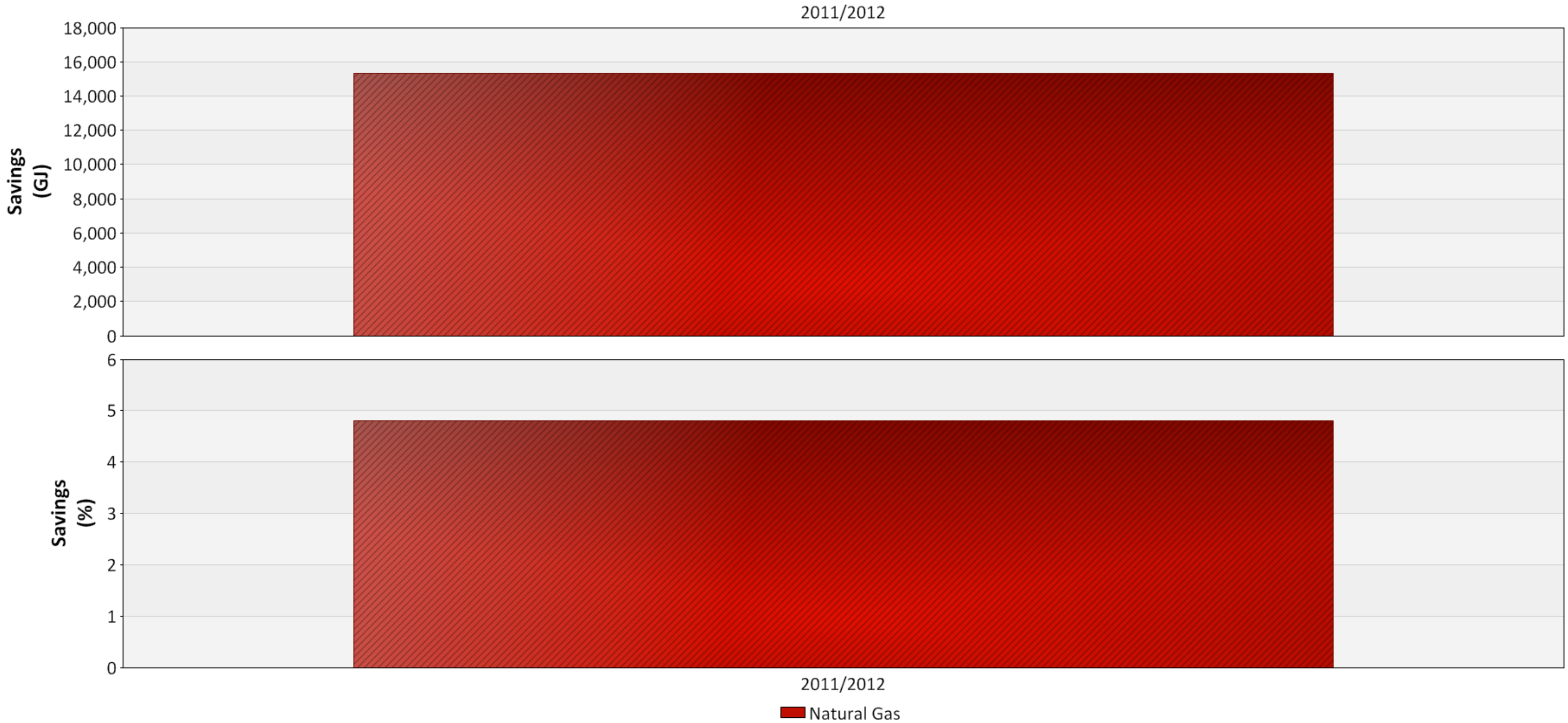


Year[1]	Natural Gas			
	Actual	Prorated Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2011/2012	528,257	651,489	123,232	19

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **Office**

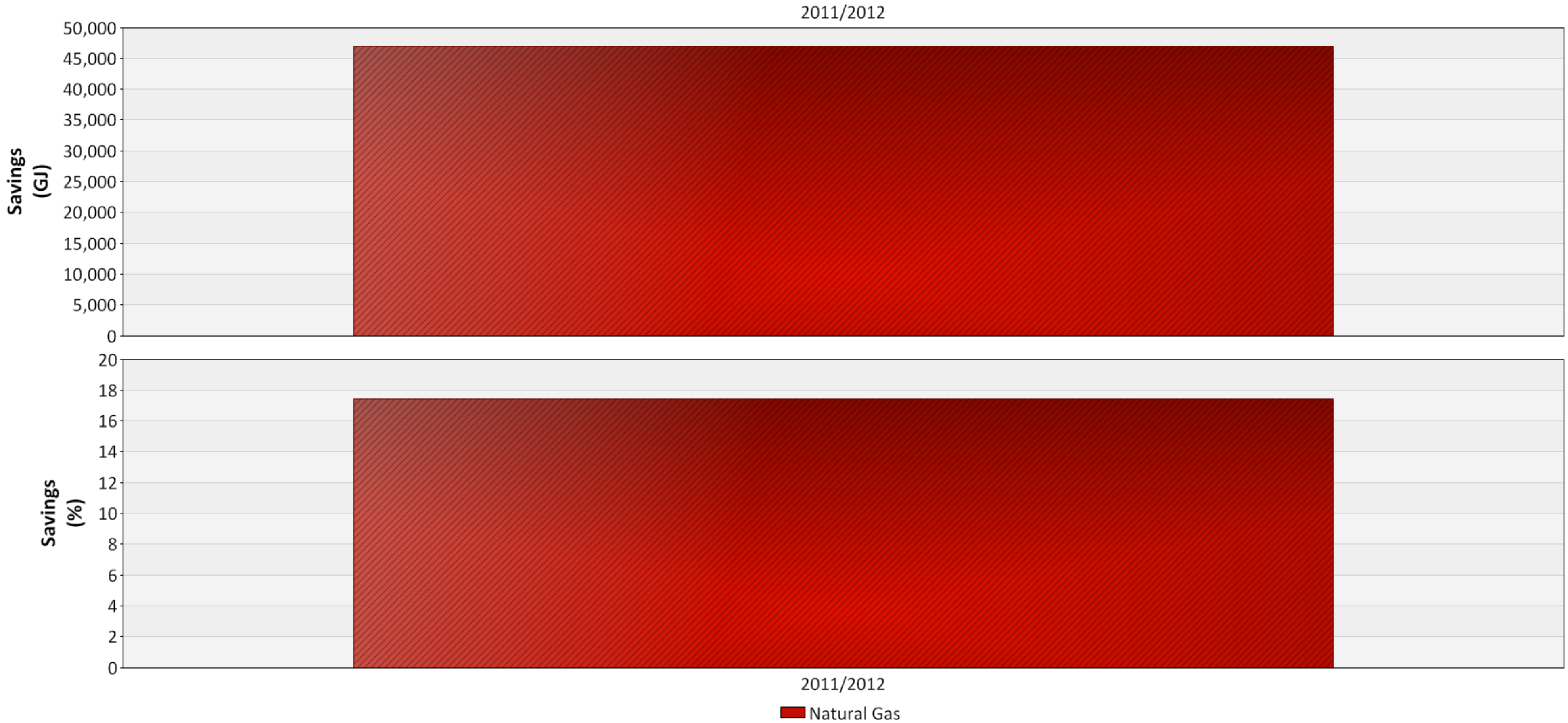


Year[1]	Natural Gas			
	Prorated Actual	Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2011/2012	303,539	318,898	15,359	5

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **Other**

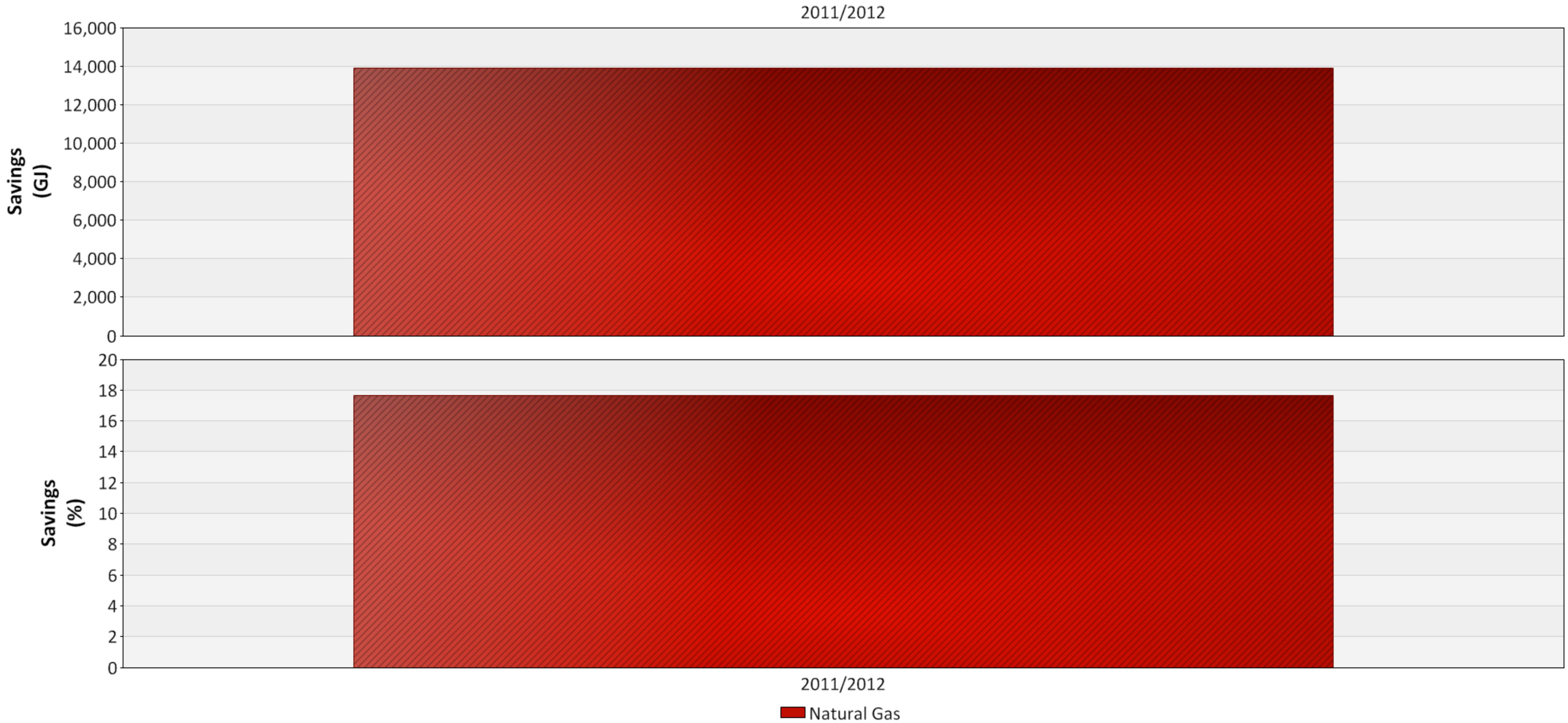


Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	222,174	269,187	47,013	17

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **School**



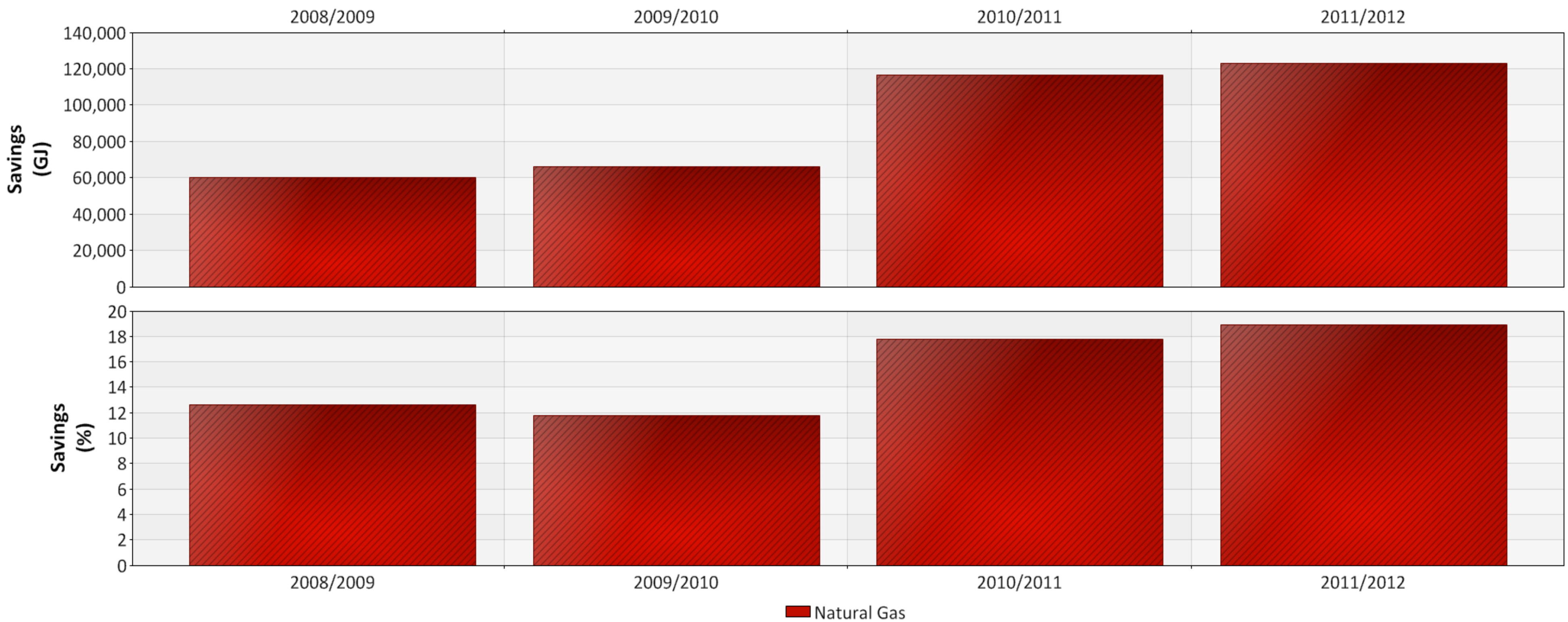
Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	64,824	78,727	13,903	18

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

APPENDIX K: Savings By Grouping By Year

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **MURB**

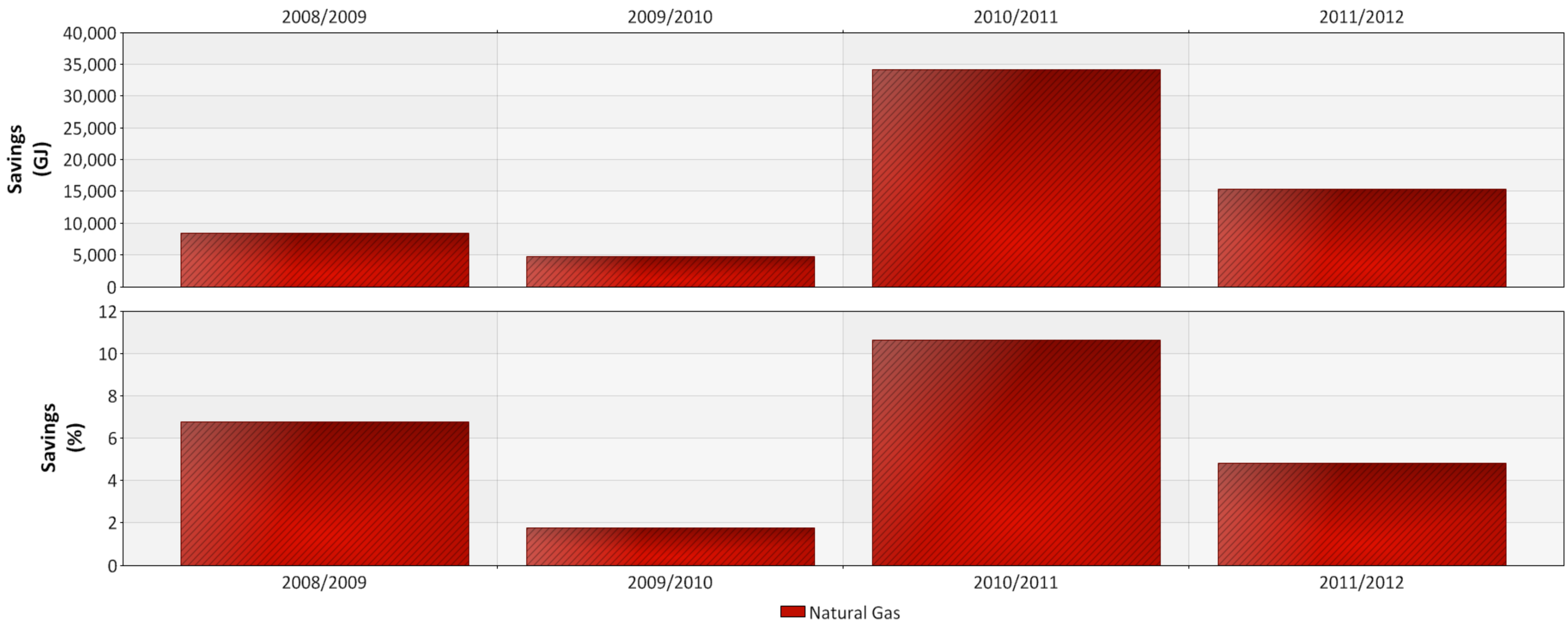


Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2008/2009	414,800	474,970	60,170	13
2009/2010	496,488	562,962	66,474	12
2010/2011	539,410	656,250	116,839	18
2011/2012	528,257	651,489	123,232	19
Total:	**1,978,956**	**2,345,671**	**366,715**	**16**

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **Office**

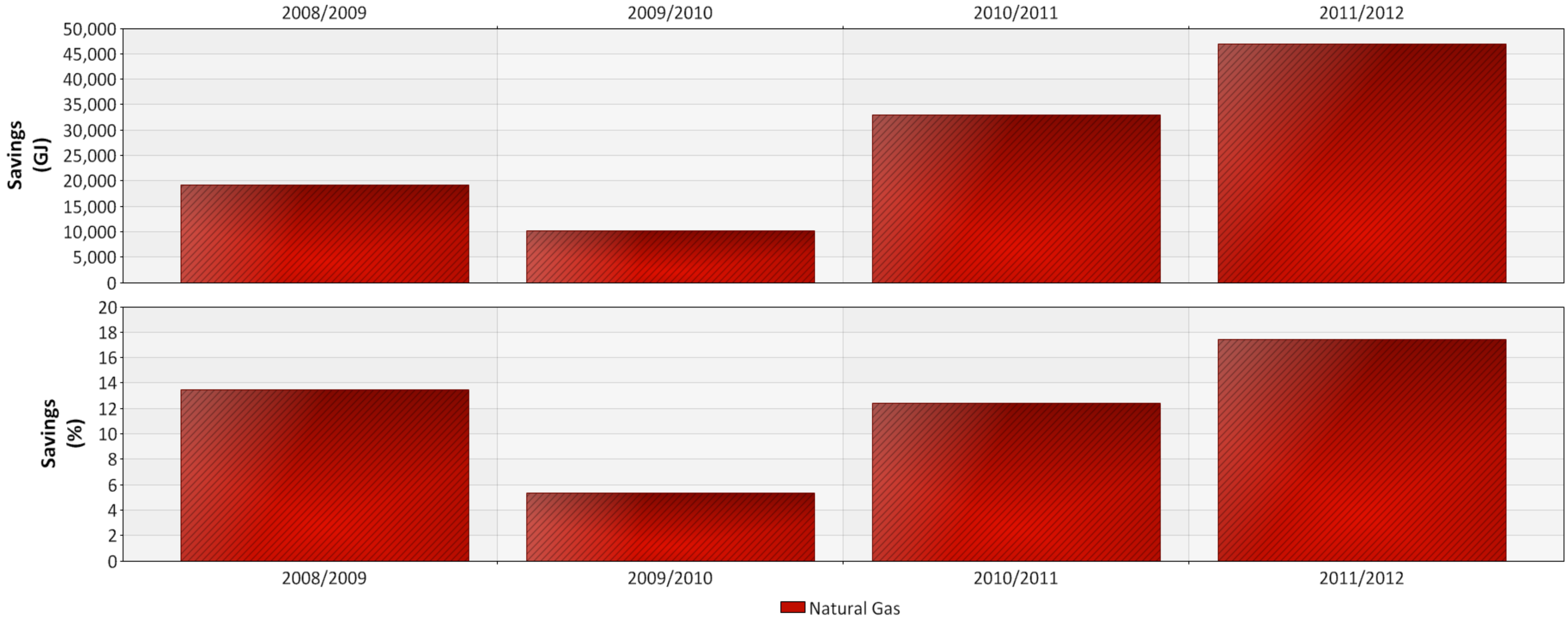


Year[1]	Natural Gas			
	Prorated Actual	Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2008/2009	116,648	125,113	8,465	7
2009/2010	261,514	266,292	4,778	2
2010/2011	287,468	321,735	34,266	11
2011/2012	303,539	318,898	15,359	5
Total:	**969,170**	**1,032,038**	**62,868**	**6**

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **Other**

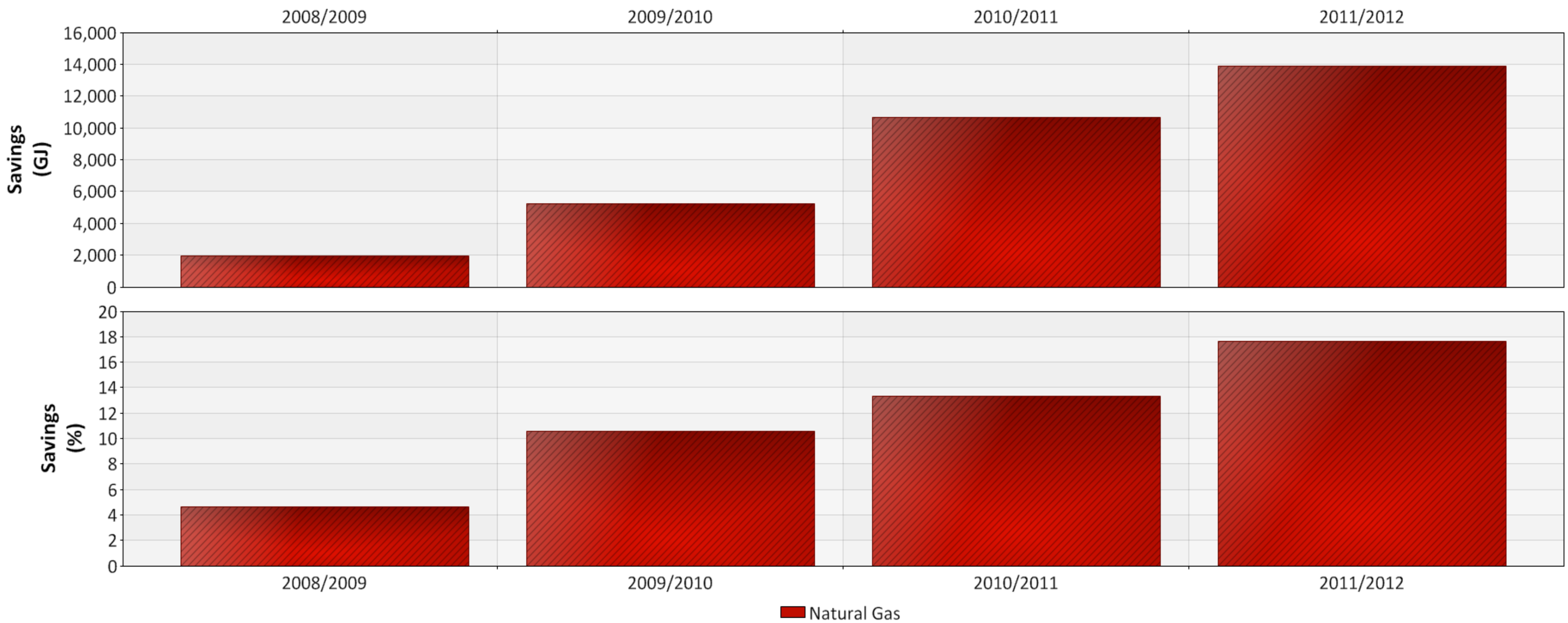


Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2008/2009	124,192	143,533	19,341	13
2009/2010	181,404	191,637	10,233	5
2010/2011	232,841	265,904	33,063	12
2011/2012	222,174	269,187	47,013	17
Total:	**760,612**	**870,262**	**109,650**	**13**

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Building Type**
Grouping: **School**



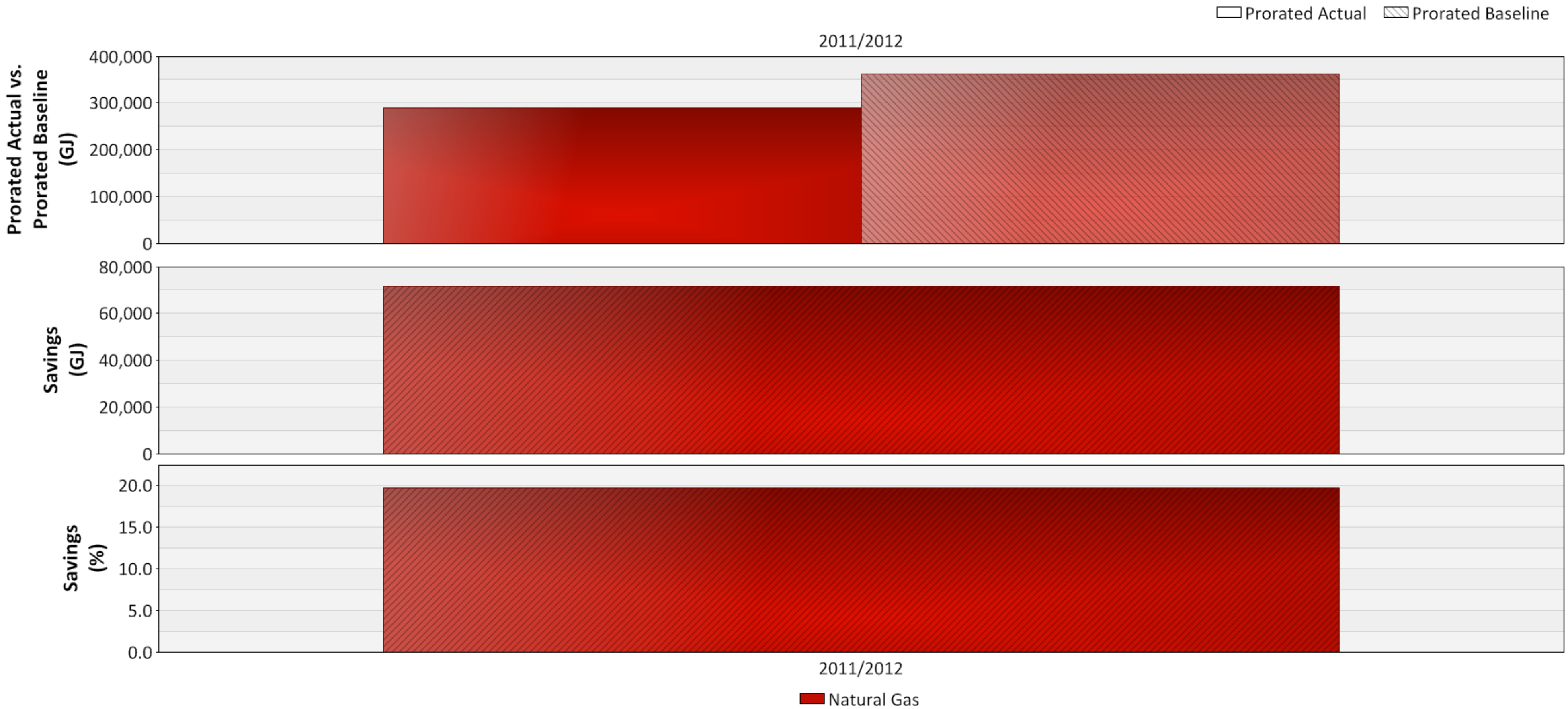
Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2008/2009	40,328	42,289	1,961	5
2009/2010	44,432	49,715	5,283	11
2010/2011	69,379	80,073	10,693	13
2011/2012	64,824	78,727	13,903	18
Total:	**218,963**	**250,803**	**31,840**	**13**

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

APPENDIX L: Savings By Boiler Efficiency Grouping By Year

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project By Boiler Efficiency**
Grouping: **High Efficiency**

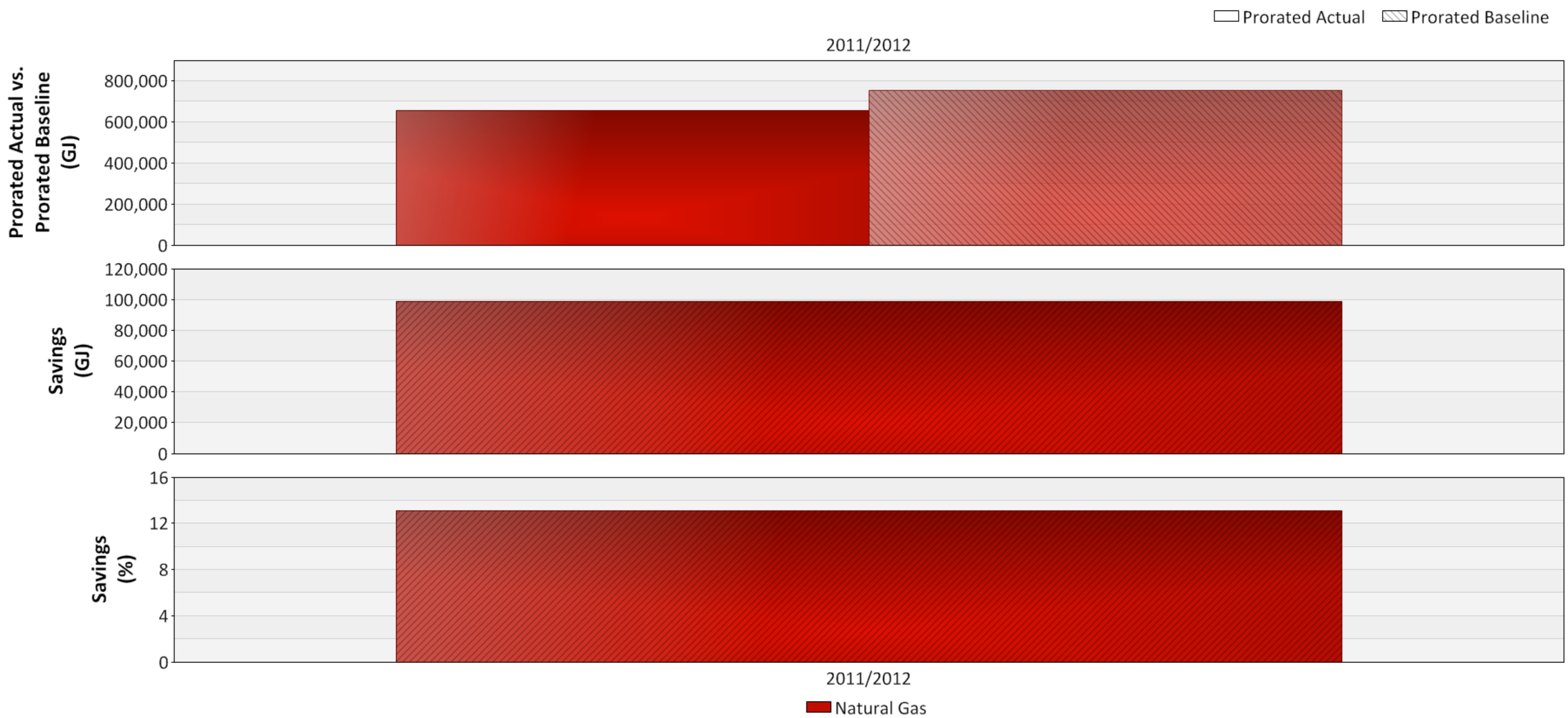


Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	290,477	362,227	71,751	20

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Savings By Grouping By Year

Project: **FortisBC Efficient Boiler Program Analysis (2011008)**
Classification: **Project By Boiler Efficiency**
Grouping: **Mid Efficiency**



Year[1]	Natural Gas			
	Prorated Actual	Prorated Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	655,237	754,330	99,093	13

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

APPENDIX M: Glossary and Definitions

EBP	Efficient Boiler Program
MURB	Multi Unit Residential Building
CUSUM	Cumulative Sum
Group 1	Participants from 2011 EBP Analysis
Group 2	Participants added in 2012 EBP Analysis
HDD	Heating Degree Days

Thermal Balance Point Temperature:

The balance point temperature characterizes the limit of the outside air temperature when heating is required. Depending on the building type and building construction the balance point temperature might vary which has an impact on the heating requirement of the building

Average Savings:

Average savings can be calculated using two different methods:

- Average savings as arithmetic average of the percentage savings of all studied sites. This figure is based on the number of sites and % savings for each of the sites and does not account for the magnitude of savings of the individual sites.
- Weighted average saving which is based on the total natural gas savings saving for all studied sites compared to the total baseline energy use for all studied sites. This figure accounts for the magnitude of savings of the individual sites. The natural gas savings are calculated as difference between baseline energy use and actual natural gas consumption.

Average savings are calculated for a 12 month period ending May of each respective year. Example: Savings for 2011/12 is calculated for savings achieved between June 1st, 2011 until May 31st, 2012.

Statistical Parameters:

- Mean, which is the average value representing the centre of gravity of the distribution and is also referred to as average;
- Median, which is the middle value above which, and below which, 50% of the values are located;
- Standard Deviation, is a measure of the typical or average distance from each value to the mean and characterizes the spread and dispersion of a data set along with the confidence interval;
- Confidence interval, which provides an interval of an upper and lower limit of savings and the confidence level with which the actual savings will fall between the upper and lower limit.

Prism ENGINEERING
saving you energy

ANALYSIS OF ENERGY SAVINGS FROM FORTISBC FIREPLACE TIMER PILOT PROJECT

Final Report

FORTIS BC™

Prepared for: Cindy Wong, FortisBC
Project No: 2012259
July 11, 2013

Limits of Liability

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

APPENDICES

1. EXECUTIVE SUMMARY

The purpose of the fireplace timer pilot was to install electronic programmable timers on decorative gas fireplaces. The timers can be set to half an hour, one hour or two hours of continuous fireplace operation. It is anticipated that the timers will reduce instances of occupants leaving gas fireplaces operating for an extended periods of time. The target audience are Multi-family residential homeowners and renters (stratas and apartment buildings).

In total, eight MURB buildings are included in the study. A total of 315 timers were installed in the eight buildings with installation dates ranging between April 2010 and December 2011. All eight buildings have more than 12 months of pre and post retrofit consumption history.

The Fireplace Timer Pilot Project projected an average annual natural gas savings of 3.0 GJ per timer installation. Results from this evaluation confirmed that this is a reasonable projection for natural gas savings. **The average annual natural gas savings for the eight buildings assessed was 5.1 GJ per timer using the 12 month post retrofit consumption period**, as shown in Figure 1. However, a wide range of annual natural gas savings per timer installation was determined for the individual buildings.

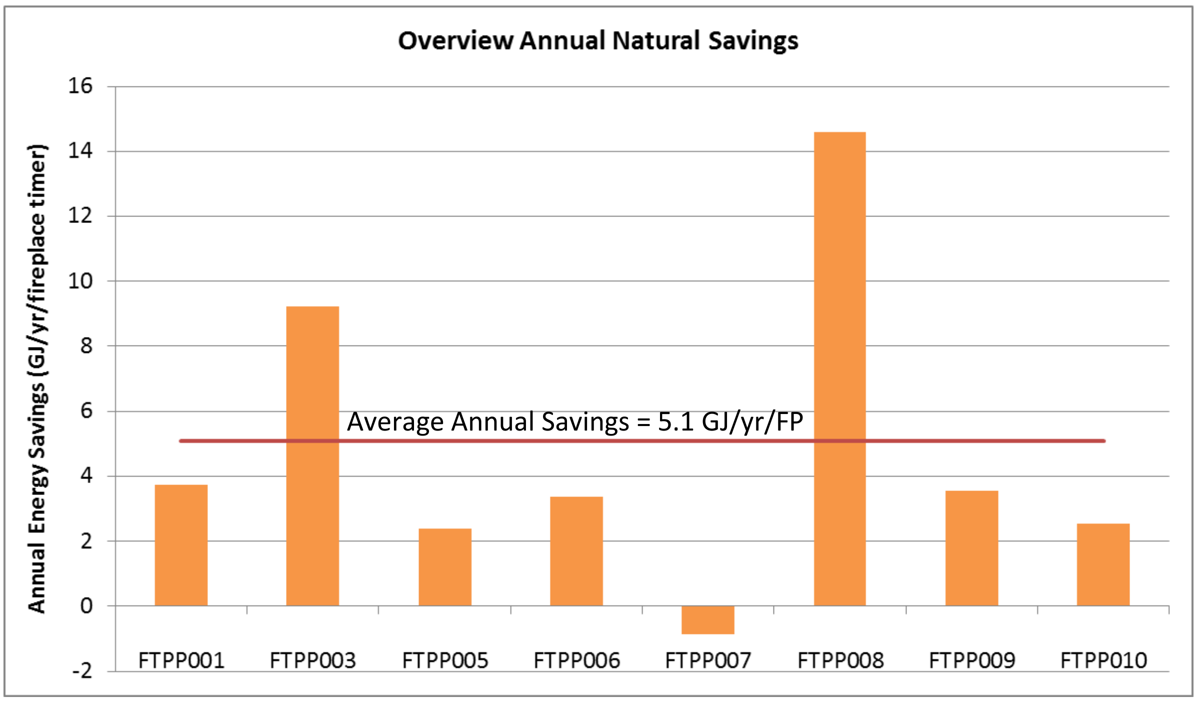


Figure 1: Annual Natural Gas Savings Per Site Per Fireplace Timer

A survey and site visits at 2 buildings (FTPP005, FTPP008) was conducted to collect further building information and gain insight into operational practices of the individual buildings. A detailed discussion of each site is performed in section 5.3.

Average Annual Savings = 5.1 GJ/yr/FP

2. BACKGROUND

2.1 Introduction

Prism Engineering Ltd. has carried out an analysis to quantify the savings associated with FortisBC's Fireplace Timer Pilot Project. The evaluation included 8 multi-unit residential buildings with 315 fireplace timer installations and allows FortisBC to gain insights into the natural savings achieved from the pilot project.

2.2 Scope

The scope of work for this project included the following:

1. Evaluate natural gas savings from the Fireplace Timer Pilot Project (total natural gas saved in GJ, natural gas saved in GJ per installation along with the average savings, actual vs. projected savings, multi-year savings trends).
2. Analysis of the data and natural gas savings segmented by building.
3. Survey on building level to assess installation of fireplace timers and implementation of other changes.
4. Where possible, assess energy impact of other changes which might have been implemented along with the fireplace timer installation.

3. METHODOLOGY

3.1 Overview

Prism used the following methodology to complete the savings analysis for this project:

1. collected and imported data for each natural gas account provided for the participants of the pilot project. A overview of the participants is provided in APPENDIX A;
2. quality analysis of consumption data to ensure that consumption data provided cover at a minimum two years of consumption prior to timer installation and one year post consumption data;
3. set up a baseline model of pre retrofit energy use using single variable linear regression. APPENDIX B provides the details of each model;
4. calculated savings achieved annually post retrofit with weather adjustments. Savings were calculated as the baseline adjusted for post retrofit periods weather conditions less the post retrofit energy use;
5. determined if other measures were implemented at the same time or prior to the timer installations which would have impacted the overall savings;
6. prepared CUSUM graph of the complete pilot project and individual buildings to review the rate, seasonality and consistency of savings; and
7. evaluated actual vs. projected savings (projections are based on FortisBC program estimate of 3.0 GJ per year and timer installation);

3.2 MT&R Software - Prism Utility Monitoring and Analysis (PUMA)

Prism has developed a database application for utility monitoring, targeting and reporting. This monitoring program:

- minimized input time of electronic data transfer from FortisBC due to existing routines; and
- includes innovative monitoring and targeting tools, such as CUSUM.

PUMA features an online interface for FortisBC to view utility monitoring and targeting reports. This web interface allows users to:

- review trends without any software (beyond an internet browser); and
- easily review consolidated or specific information via customizable reports.

FortisBC has been given online access to PUMA for this project for a period of six months and can view all accounts and the natural gas savings analysis carried out.

3.3 Data Provided by FortisBC

FortisBC has provided the following information:

1. monthly gas consumption with reading date and days in electronic format with the last reading dates as shown in APPENDIX C;
2. building information (type, number of units, site contact and physical location); and
3. fireplace information (total number of fireplaces, number of fireplaces with timer installations and installation date of timers).

Prism has treated all data as confidential.

3.4 Participants Survey

A total of nine buildings participated in the Fireplace Timer Pilot Project. The following participants were not surveyed:

- FTPP017 was excluded from the analysis and survey as only 5 months of post retrofit data was available which is insufficient for a representative analysis; and
- FTPP010 was excluded from the survey as the contact information was not up to date.

The remaining 7 participants were asked to complete a phone based survey with the following questions:

- 20 questions to obtain basic building information on the heating system, gas consuming equipment and any changes in systems;
- 3 site specific questions to help answer the savings results for each site; and
- 6 FortisBC standard satisfaction questions.

The survey questions are provided in APPENDIX D and the results are provided in APPENDIX E of this report.

4. SURVEY

4.1 Survey Results

Of the seven program participants which were targeted to be surveyed, five participants responded to the phone survey. The survey was structured in the following three sections:

- Building Equipment: to assess the scope of gas consuming equipment in each of the buildings;
- Fireplace Survey: to assess the acceptance of the timer installation; and
- FortisBC Standard Satisfaction Questions

Table 1 provides an overview of the survey results and the detailed results are provided in APPENDIX E of this report.

Table 1: Summary of Survey Result

Heating System	Electric	Hydronic (Gas Boiler)
	6	1
Domestic Hot Water	Gas Boiler or Hot Water Tank	Electric
	5	2
Make Up Air Unit	Yes	No
	6	1
	Gas for heating	Electric, no heating or not specified
	2	5
Was the fireplace timer installation well received by the occupants?	Yes	No
	5	2

The building equipment assessment section of the survey provided following result:

- 6 out of 7 buildings are equipped with electric baseboard heaters in the suites and only one building uses a natural gas as an energy source for heating;
- the two smaller buildings which responded to the survey are equipped with electric hot water tanks in the suites whereas the larger buildings provide domestic hot water through a centralized boiler or gas fired domestic hot water tank; and
- most of the property managers were unsure about the make-up air unit and the source of heating for this unit.

Two participants responded that the fireplace timer installation was well received by the occupants of the buildings. One participant informed us that some of the occupants provided positive feedback while others were dissatisfied. In response to our question as to why occupants were dissatisfied, we receive the response that some of the occupants generally do not accept changes very well. The two negative responses to this question provided following reasons:

- occupants complained that it gets too cold at night after the timer installation. This indicates that occupants have been using the fireplace as a source of heating; and
- problems occurred during the installation process. We found out that the installation problem did not concern the fireplace timer installation but rather that the participant was dissatisfied with the contractor.

The results of the site specific survey questions are presented in section 5.2 with the analysis of the individual sites.

5. ANALYSIS

5.1 Overall Natural Gas Savings

For each meter, the natural gas savings were evaluated by comparing the pre and post retrofit data. A regression analysis was done on 12 month of data immediately prior to the fireplace timer installations to identify the energy use model and dependence on weather. This period is referred to as the "base period" and its trend of consumption as "baseline". Energy use after the base period was compiled from the FortisBC billing system and then compared to baseline consumption for evaluation of the natural gas savings.

The CUSUM for the entire project (including all eight applicants) shown below in Figure 2 and in APPENDIX F demonstrates that savings were achieved starting November 2010 and significant change in savings performance commenced September 2011. This correlates with the installation dates of the fireplace timers of participant FTPP003 (80 unit MURUB) who completed the retrofit in August 2011. Cumulatively, over 1,916 GJ of natural gas saving was achieved for all fireplace timer installations up to end of the last read dates as provided for each individual site.

Natural gas savings were achieved during heating periods with a steep incline in savings for the 2011 / 2012 heating season. A consistent savings performance can be observed during the heating season and slightly negative or neutral performance during non-heating seasons. The CUSUM for each site is shown in APPENDIX G.

Between June and September 2011an increase in consumption was observed which represents a non - heating related increase in gas consumption. Our analysis showed that a baseload increase at one of the participating sites as a result of increased occupancy. Note that the adjustment for FTPP005 is not included in the CUSUM graph.

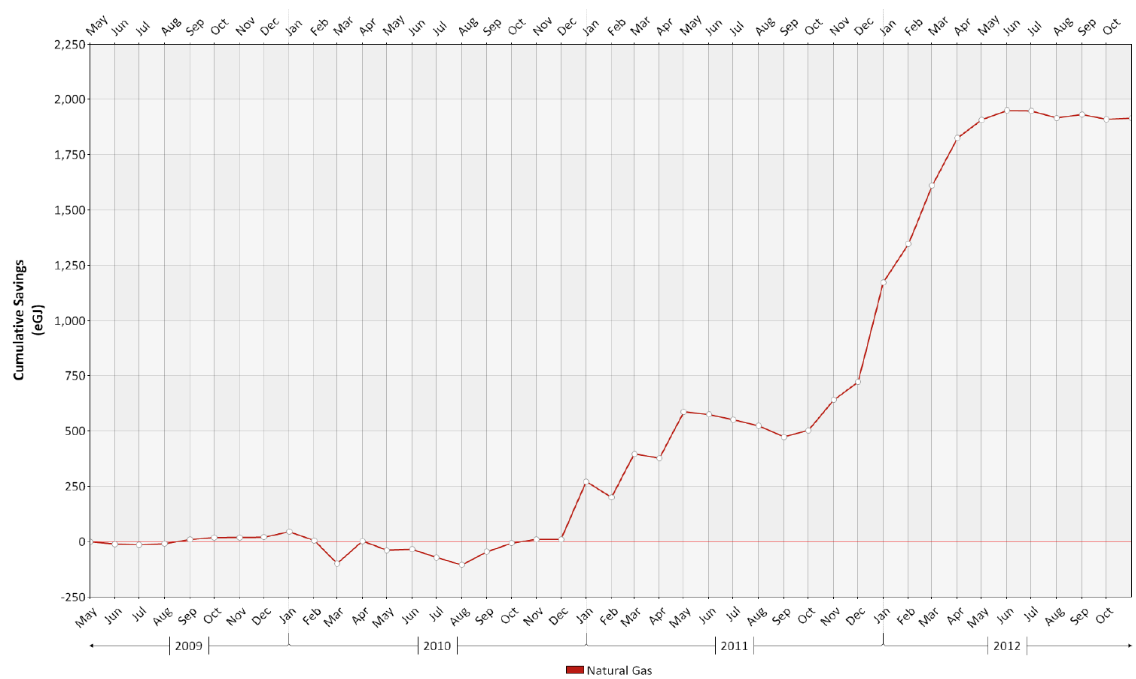


Figure 2: CUSUM of Complete Projects All Sites

5.2 Annual Natural Gas Savings

An overview of the annual natural gas savings (12 month period) is provided in Table 2. The average annual natural gas savings across all sites was determined as the total annual savings of 1,600 GJ/year over a total of 315 installed fireplace timers. This results in an average annual natural gas savings of 5.1 GJ/yr per fireplace timer installation.

Table 2: Annual Natural Gas Savings

Application Number	Premise Number	# Fireplace Timer installed	Annual Savings (GJ/year)	Annual Savings (GJ/year/timer)
FTPP001	763042	63	235	3.7
FTPP003	743213	73	673	9.2
FTPP005	713430	50	120	2.4
FTPP006	471682	10	34	3.4
FTPP007	59502	35	-30	-0.9
FTPP008	291374	27	394	14.6
FTPP009	486157	30	106	3.5
FTPP0010	721055	27	69	2.5
Total		**315**	**1,600**	**5.1**

Figure 3 shows the annual average natural gas savings per fireplace timer installation for each individual site:

- 4 buildings perform within reasonable deviation from anticipated annual savings of 3.0 GJ per fireplace timer installation;
- 2 buildings performed well above average; and
- 2 buildings had low or negative savings.

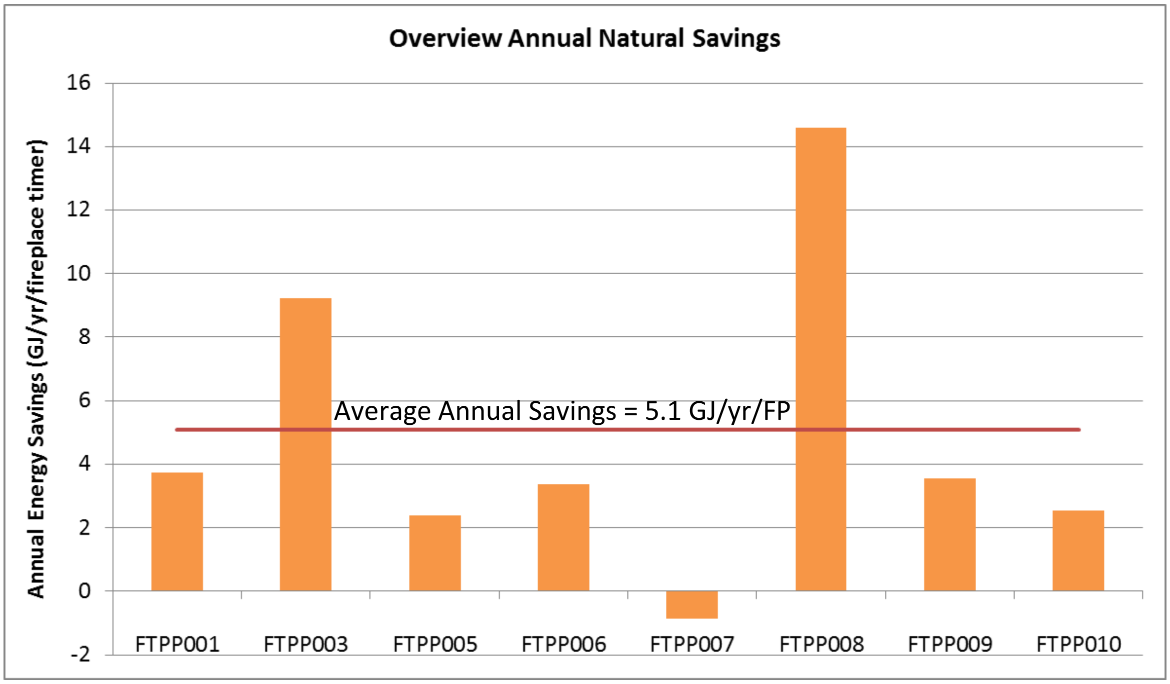


Figure 3: Annual Natural Gas Savings Per Site Per Fireplace Timer

The graph demonstrates the range of savings that have been determined. The reason for this wide variance is discussed on a building by building basis in the next section. A survey was conducted to obtain site specific information to further explain the differences in performance.

5.3 Energy Analysis by Site

To further analyse the natural gas savings performance of the individual buildings and to provide explanations to the wide spread of achieved savings per fireplace timer a detailed review of each building was performed. Survey results are included in the analysis where applicable. The annual natural savings reports of each individual building are included in APPENDIX H.

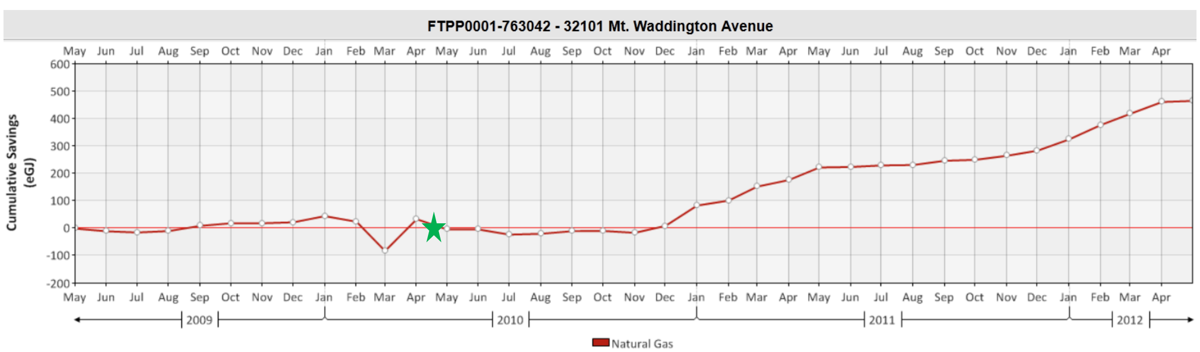
FTPP001

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
63	63	63	Apr 21st, 2010

Participant FTPP001 is a medium size residential building where all suites are equipped with fireplaces and were retrofitted with fireplace timers. Heating is provided with electric baseboard heaters and domestic hot water is the only other confirmed gas consuming equipment in the building besides the fireplaces. The property manager who responded to the survey was unsure about the heating source for the make-up air unit.

12 month period	Gas Savings (GJ)	Savings Per Timer
May 2010 – Apr 2011	226 GJ	3.6 GJ/Timer
May 2011 – Apr 2012	243 GJ	3.9 GJ/Timer

Figure 4 shows a savings trend starting November 2010 which correlates with the beginning of the first heating season after the fireplace timer installation. A flattening of the performance was observed during the summer months which indicate that the savings are weather dependent.



Legend: ★ Fireplace Timer Installation

Figure 4: FTPP001 CUSUM

FTPP003

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
80	80	73	Aug 23rd, 2011

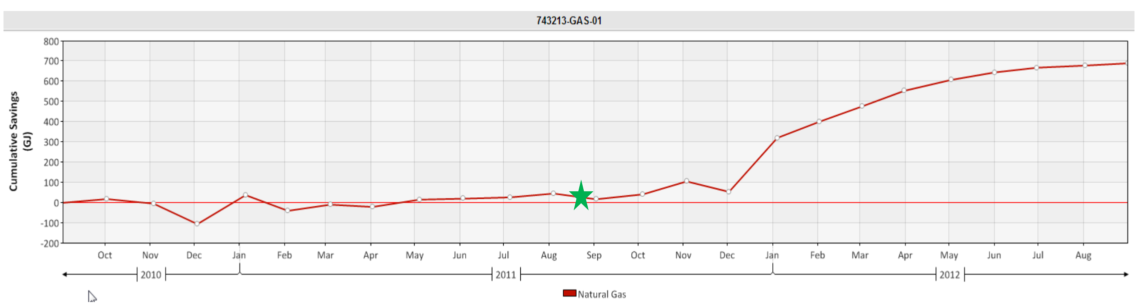
Participant FTPP003 consists of two residential buildings with a total of 80 suites and both buildings are provided with natural gas through one common account. All suites are equipped with fireplaces and the majority of the suites were retrofitted with a fireplace timer. Heating is provided with electric baseboard heaters and domestic hot water is the only other gas consuming equipment in the building besides the fireplaces. The maintenance manager who is also involved in the strata council responded to the survey and was able to provide excellent information on the existing building systems, and operational practices.

12 month period	Gas Savings (GJ)	Savings Per Timer
Sep 2011 – Aug 2012	673 GJ	9.2 GJ/Timer

The natural gas savings were assessed for a period of twelve months which covers the complete first heating season after the fireplace timer installations.

Natural gas savings are observed starting December 2011 as shown in Figure 5. The savings trend is consistent over the heating season with a decrease in slope towards the non-heating season. The savings of 9.2 GJ per timer installation for the first twelve months after the retrofit is higher than observed with the participants. The following information was provided by the building caretaker to explain the higher savings:

- rental units within the two buildings were observed to excessively use their fireplaces throughout the entire year; and
- fireplaces were observed to be operating even when occupants were not in their suites such as during daytime or sometimes even for extended periods of time.



Legend: ★Fireplace Timer Installation

Figure 5: FTPP003 CUSUM

FTPP005

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
83	95	50	March 14th, 2011

Participant FTPP005 is a building complex with apartment units and town homes. All of the units are strata units and it was planned to install 80 fireplace timers. During the site visit we were informed approximately 60% of all fireplace timers were installed and operating during the heating season of 2011 / 2012. The property management received complaints from some units that fireplaces could not be operated after the installation of the fireplace timers. Faulty fireplace timers were replaced with wall switches until replacement timers were available. There are still a few units which have not been retrofitted with timers due to the availability.

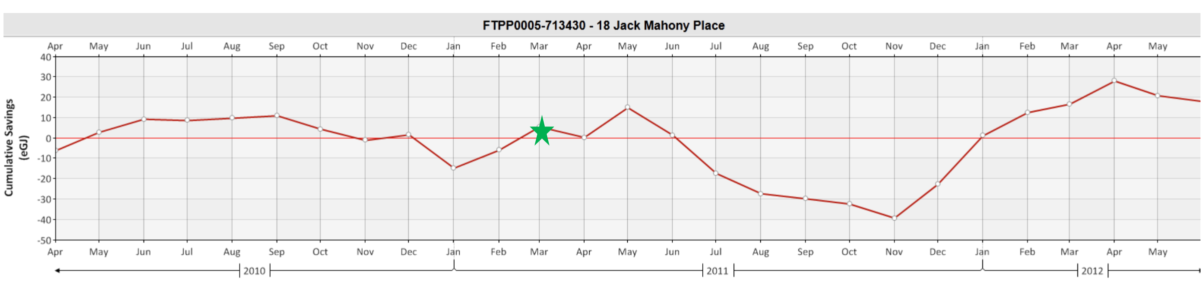
12 month period	Gas Savings (GJ)	Savings Per Timer
Mar 2011 – Feb 2012	120 GJ	2.4 GJ/Timer

As shown in Figure 6 an increase in consumption, which appears to be non weather dependent, was observed starting May 2011 until November 2011. We were provided the following information which could explain the increase in gas consumption during the summer months:

- one of the domestic hot water boilers was replaced in May 2011 and it could not be verified that the replacement boiler was of the same capacity as the original boiler; and
- increase in occupancy within the last 12 months as more young families with children moved in.

Savings were achieved in the first heating season after the timer installations which were consistent over the heating period. The below average annual savings per fireplace timer installation can be explained by the following:

- natural gas baseload increased by 16% (baseload comparison of 12 months pre verses post installation. We estimated annual gas savings per fireplace timer of 2.4 GJ/Timer/year after removing the increase baseload. This amount was added to the savings.
- it is unknown how many of the wall switches were replaced with properly working timers before the start of the first heating season and occupants in strata units are generally more conscious of energy consumption.



Legend: ★ Fireplace Timer Installation

Figure 6: FTPP005 CUSUM

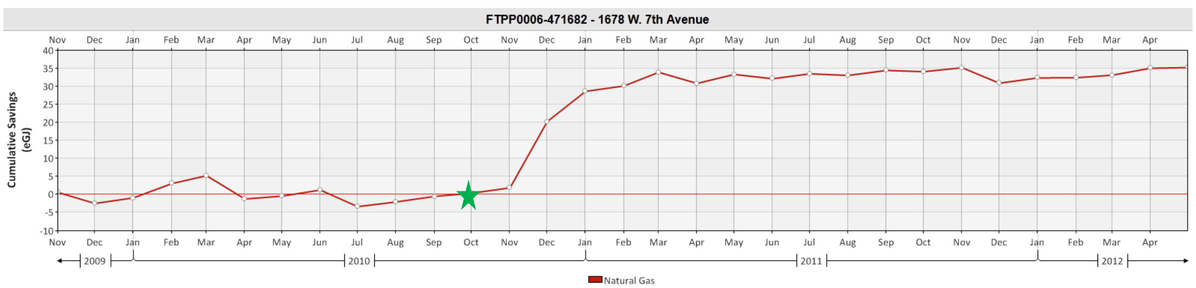
FTPP006

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
10	10	8	October 10th, 2010

Participant FTPP006 is a small residential building where all suites are equipped with fireplaces now retrofitted with fireplace timers. However, during the first heating season only 8 out of 10 fireplaces were functional. Natural gas provided to the building is solely for the suite fireplaces.

12 month period	Gas Savings (GJ)	Savings Per Timer
Oct 2010 – Sep 2011	34 GJ	4.2 GJ/Timer

Natural gas savings were observed starting November 2010 with a decrease in slope starting March 2011, as shown in Figure 7. The savings achieved during the first 12 month period after the fireplace timer installation aligns well with the overall average of the complete pilot project. However, minimal energy savings were observed during the 2011/2012 heating season. The property manager who responded to the survey did not report any changes in operational practices over the last 12 months.



Legend: ★ Fireplace Timer Installation

Figure 7: FTPP006 CUSUM

FTPP007

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
39	39	35	June 20th, 2011

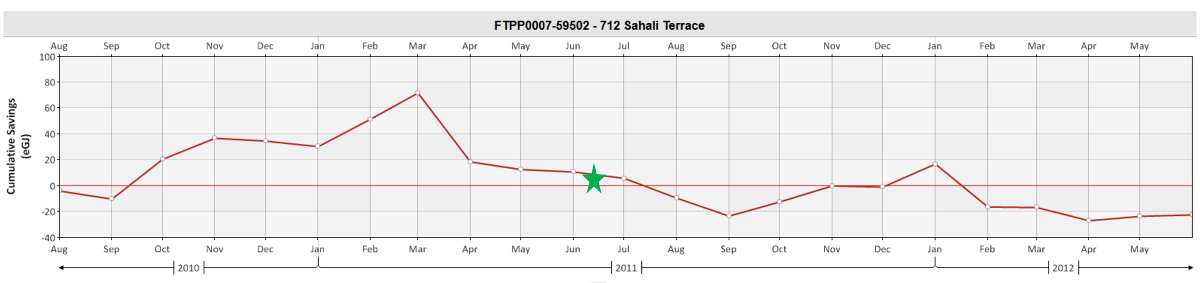
Participant FTPP007 is a small residential building where all suites are equipped with fireplaces and the majority of the fireplaces were retrofitted with fireplace timers. The heating system is comprised of a natural gas fired heating boiler and hydronic baseboard heaters in the suites. Domestic hot water is provided by electric heaters in the suites. The property manager who responded to the survey could not provide us with information regarding the make-up air unit.

10 month period	Gas Savings (GJ)	Savings Per Timer
Jul 2011 – Apr 2011	-30 GJ	-0.9 GJ/Timer

As shown in Figure 8 the natural gas consumption trend after the fireplace timer installation remained fairly consistent without any significant changes. No savings were achieved in this building which could be due to following circumstances:

- natural gas consumption of the fireplace is only a small portion of the overall gas consumption;
- fireplaces were mainly used for decorative purposes prior to the timer installation; and
- generally we would anticipate lower savings in buildings with hydronic heating as reduced usage of the fireplace will be substituted by increased heating if fireplaces were used as a heating source prior to the timer installation.

FTPP007 is the only building among all participants where we could confirm that heating was provided through natural gas.



Legend: ★ Fireplace Timer Installation

Figure 8: FTPP007 CUSUM

FTPP008

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
27	27	27	January 6th, 2011

Participant FTPP008 is a small residential building with 27 units which are all equipped with fireplaces and were retrofitted with fireplace timers. All 27 units are rental units.

12 month period	Gas Savings (GJ)	Savings Per Timer
Jan 2011 – Dec 2011	394 GJ	14.6 GJ/Timer

Natural gas savings were achieved immediately after the fireplace timer installations which was consistent over the heating period. Figure 9 shows that the achieved savings were entirely weather dependent as the slope of accumulated saving is flat over the summer months.

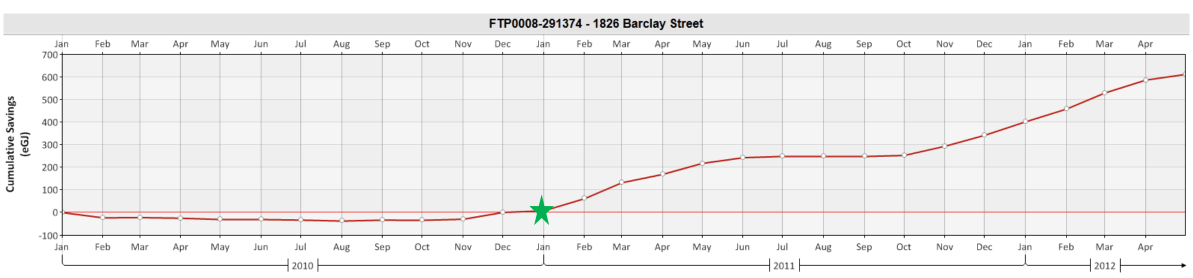
Natural gas savings of 394 GJ or 14.6 GJ per fireplace timer installation was achieved during the first 12 month period. The comparison of the pre and post retrofit regression model parameter showed that the baseload remained constant while the heating slope was almost reduced to half. This indicates that the natural gas savings of 394 GJ or 23% of the total annual gas consumption is solely heating related.

A site visit was conducted to investigate the above average natural gas savings of this site. The caretaker provided the following information:

- it was observed that renters leave their fireplace operating even when they are not home during the day; and
- in some instances it was observed that renters left their fireplace operating even when they are away for an extended period of time.

A comparison of the regression model pre and post installation showed the following:

- baseload remained the same which confirms the care taker's information that the occupancy has been consistent
- reduction in weather sensitive load by 36% which suggest that the fireplaces have been used less for heating purposes.



Legend: ★ Fireplace Timer Installation

Figure 9: FTPP008 CUSUM

FTPP009

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
51	33	30	June 9th, 2011

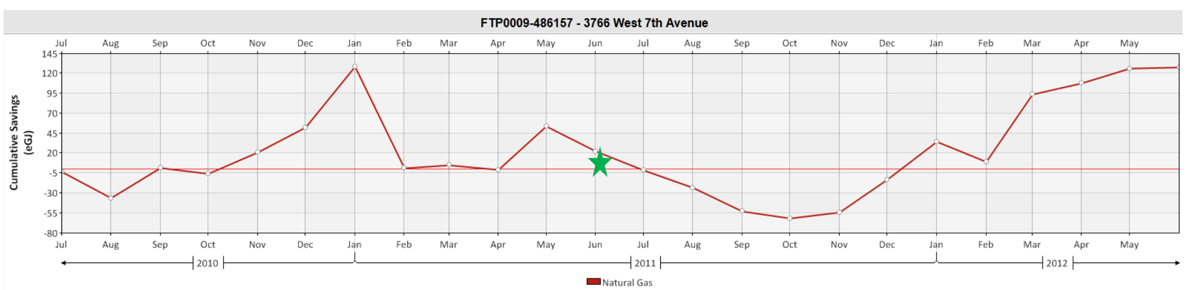
Participant FTPP009 is a medium size residential building with 51 suites. Thirty fireplaces were retrofitted with fireplace timers. The property manager who responded to the survey informed us that she has only recently taken over the management of the building. As such, she could only provide limited information on the building systems and no information on the operational practices of the building.

10 month period	Gas Savings (GJ)	Savings Per Timer
Jul 2011 – Apr 2012	106 GJ	3.5 GJ/Timer

Only 10 months of post retrofit energy consumption data was available for the savings analysis of FTPP009. However, the provided data covers the entire first heating season after the fireplace timer installation.

As shown in Figure 10 natural gas savings were achieved starting with the first heating season after the fireplace timer installation. However, an event prior to the fireplace timer installation caused an increase in gas consumption during the summer months of 2011. We were unable to identify the cause.

Natural gas savings of 105 GJ or 3.5 GJ per fireplace timer installation was achieved during the first 10 months after the retrofits.



Legend: ★ Fireplace Timer Installation

Figure 10: FTPP009 CUSUM

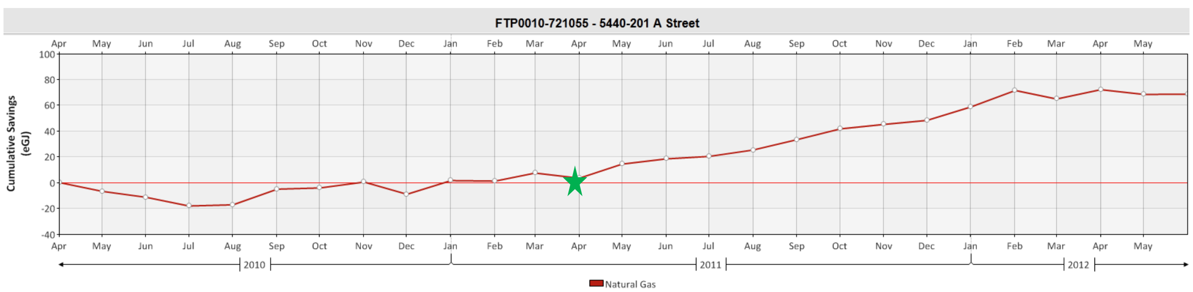
FTPP010

# Suites	# Fireplaces	# Fireplace timers	Timer Installation Date
27	27	27	March 28th, 2011

Participant FTPP010 is a small residential building with 27 suites and all suites were retrofitted with fireplace timers. We were unable to obtain further information of the building through the survey.

12 month period	Gas Savings (GJ)	Savings Per Timer
Apr 2011 – Mar 2012	69 GJ	2.5 GJ/Timer

A positive change in slope of the CUSUM was observed soon after the fireplace timer installation. Natural gas savings of 69 GJ or 2.5 GJ per fireplace timer installation was achieved during the first 10 months after the retrofits.



Legend: ★ Fireplace Timer Installation

Figure 11: FTPP010 CUSUM

6. RECOMMENDATIONS

6.1 Participant Selection and Data Collection

It is recommended to establish a questionnaire to collect site specific information such as the base heating system, other gas consuming equipment on site and operational history of equipment impacting gas consumption. This questionnaire should be a mandatory document which has to be filled out by the applicant along with the application for the Fireplace Timer Pilot Project. The gathered information would be beneficial for the following reasons:

- efforts of M&V analysis could be reduced as the site specific information would not have to be gathered through surveys which generally do not achieve 100% response rate; and
- it would allow an improved selection of participants providing a larger sample size of different groupings such as by base heating system.

Furthermore our experience is that maintenance personal and on-site live-in caretakers are generally more aware of operational practises than the Property Managers. As such, discussions with maintenance personal provide better insight and we recommend involving maintenance staff in the application process.

6.2 Grouping by Base Heating System

A saving comparison of buildings with electric heating against hydronic heating (natural gas fired boiler) might provide further understanding if the savings achieved is dependent on the base heating system. For an objective comparison we recommend including an analysis of the tenant's electricity consumption in buildings with electric heating in comparison to buildings with hydronic heating.

Such an analysis could not be carried out with the current scope of participants due to the limited sample size of buildings with hydronic heating system.

6.3 Include Electricity in Analysis

We recommend including electricity in the savings analysis to determine the net energy savings resulting from the fireplace timer installations in MURBs with electric heating as base heating system.

An analysis of the net energy savings will include:

- Gathering of tenant electricity AHR of at least one year pre and post fireplace timer installation;
- analysis of pre and post regression models, both gas and electricity, regarding baseload and weather sensitive load; and
- weather corrected savings analysis of gas and electricity.

6.4 Tracking savings ongoing

Now that all account baselines have been set up in PUMA and are available online, FortisBC may wish to continue to use MT&R with PUMA as a part of the Fireplace Timer Pilot Project to track and verify savings on an annual basis to access the persistence of the savings seen in the pilot project

APPENDIX A: PARTICIPANTS FIREPLACE TIMER PILOT PROJECT

Application Number:	Premise Number	Site Address	# of Dwelling Units	# of Decorative Fireplaces	# of Fireplace Timers Installed	Installation Date
FTPP0001	763042	32101 Mt. Waddington Av, Abbotsford	63	63	63	April 21, 2010
FTPP0003	743213	2575 Ware Street, Abbotsford	80	80	73	August 23, 2011
FTPP0005	713430	18 Jack Mahony Place, New Westminster	83	95	50 (*)	March 14, 2011
FTPP0006	471682	1678 W. 7th Avenue, Vancouver (ring intercom #32)	10	10	10	October 8, 2010
FTPP0007	59502	712 Sahali Terrace, Kamloops	39	39	35	June 20, 2011
FTP0008	291374	1826 Barclay Street, Vancouver	27	27	27	January 6, 2011
FTP0009	486157	3766 West 7th Ave., Vancouver	51	33	30	June 9, 2011
FTP0010	721055	5440-201 A St., Langley	27	27	27	March 28, 2011
FTP0017	307213	6188 Patterson Avenue, Burnaby	139	139	118	November 24, 2011

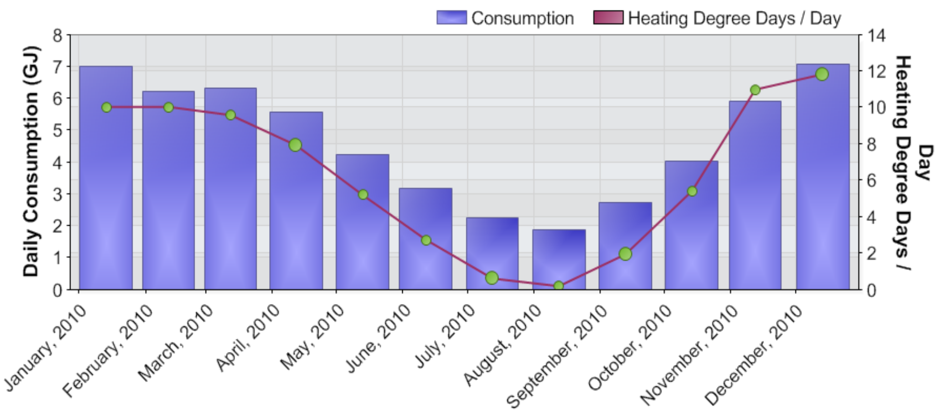
(*) Initially a number of 80 installed fireplaces were reported. During the site visit the property manager provided the information that only 60% of the fireplace timer were installed due to shortage of timers.

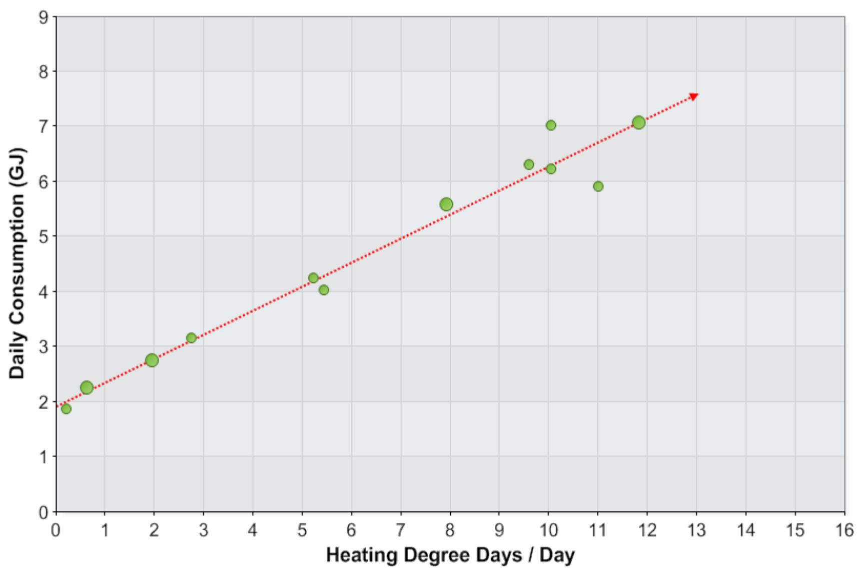
APPENDIX B: MODEL ANALYSIS

Model Analysis

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0008-291374 - 1826 Barclay Street**
Meter: **291374-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption **Selected As:** 2012259's Baseline **Base Period:** 2009-12-30 to 2010-12-29 **Base Load:** 1.915 GJ / Day **R²:** 0.967 **CV(RMSE):** 7.741
NDB: 0 **Parameter:** Daily Temperature **Balance Point:** 17.00 **Weather Factor:** 0.437 GJ / HDD **P-Value:** 100.00%



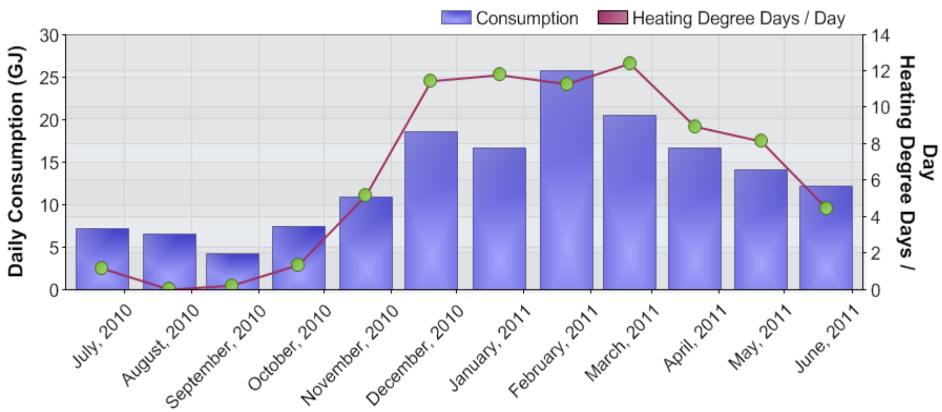


Start Date	End Date	Days	Consumption GJ	GJ / Day	Weight	HDDs / Day	Baseline GJ	Deviation %
2009-12-30	2010-01-27	29.00	203.60	7.021	0.953	10.04	182.6	11.5
2010-01-28	2010-02-25	29.00	180.70	6.231	0.953	10.04	182.7	-1.1
2010-02-26	2010-03-26	29.00	183.00	6.310	0.953	9.59	177.0	3.4
2010-03-27	2010-04-27	32.00	178.40	5.575	1.052	7.93	172.1	3.6
2010-04-28	2010-05-27	30.00	127.60	4.253	0.986	5.21	125.6	1.6
2010-05-28	2010-06-25	29.00	91.90	3.169	0.953	2.75	90.3	1.7
2010-06-26	2010-07-28	33.00	74.20	2.248	1.085	0.62	72.2	2.8
2010-07-29	2010-08-26	29.00	54.10	1.866	0.953	0.20	58.1	-6.9
2010-08-27	2010-09-28	33.00	90.50	2.742	1.085	1.95	91.3	-0.9
2010-09-29	2010-10-27	29.00	116.80	4.028	0.953	5.42	124.2	-6.0
2010-10-28	2010-11-26	30.00	177.30	5.910	0.986	11.00	201.5	-12.0
2010-11-27	2010-12-29	33.00	233.30	7.070	1.085	11.84	233.8	-0.2

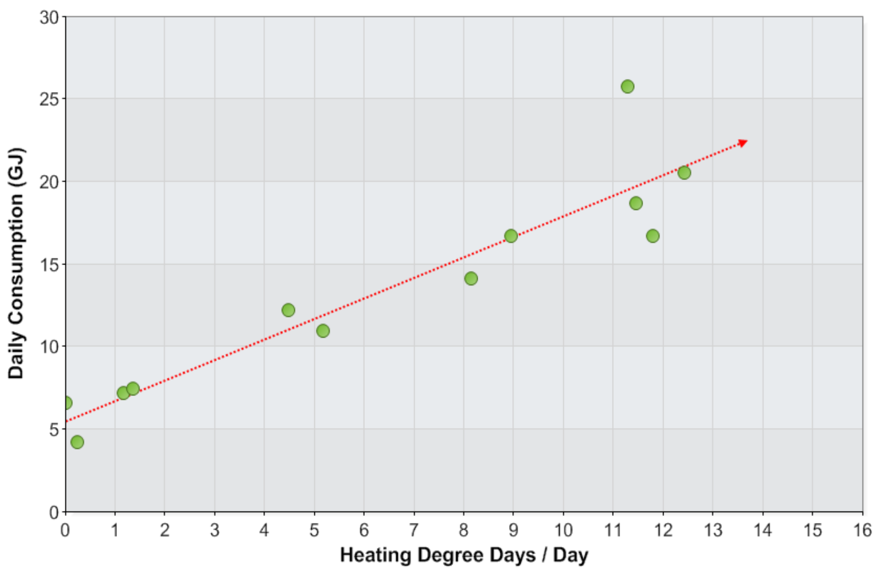
Model Analysis

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0009-486157 - 3766 West 7th Avenue**
Meter: **486157-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption **Selected As:** 2012259's Baseline **Base Period:** 2010-06-04 to 2011-06-03 **Base Load:** 5.481 GJ / Day **R²:** 0.871 **CV(RMSE):** 18.25
NDB: 0 **Parameter:** Daily Temperature **Balance Point:** 16.00 **Weather Factor:** 1.244 GJ / HDD **P-Value:** 100.00%



Start Date	End Date	Days	Consumption GJ	Consumption GJ / Day	HDDs / Day	Baseline GJ	Deviation %
2010-06-04	2010-07-06	33.00	237.3	7.19	1.17	228.9	4
2010-07-07	2010-08-04	29.00	191.4	6.60	0.01	159.2	20
2010-08-05	2010-09-02	29.00	122.0	4.21	0.23	167.4	-27
2010-09-03	2010-10-04	32.00	238.4	7.45	1.36	229.6	4
2010-10-05	2010-11-03	30.00	328.8	10.96	5.18	357.6	-8
2010-11-04	2010-12-03	30.00	559.4	18.65	11.45	591.9	-5
2010-12-04	2011-01-05	33.00	551.5	16.71	11.79	664.8	-17
2011-01-06	2011-02-03	29.00	745.9	25.72	11.29	566.4	32
2011-02-04	2011-03-04	29.00	594.4	20.50	12.42	606.9	-2
2011-03-05	2011-04-04	31.00	516.7	16.67	8.96	515.4	0
2011-04-05	2011-05-04	30.00	422.3	14.08	8.14	468.3	-10
2011-05-05	2011-06-03	30.00	365.6	12.19	4.48	331.6	10

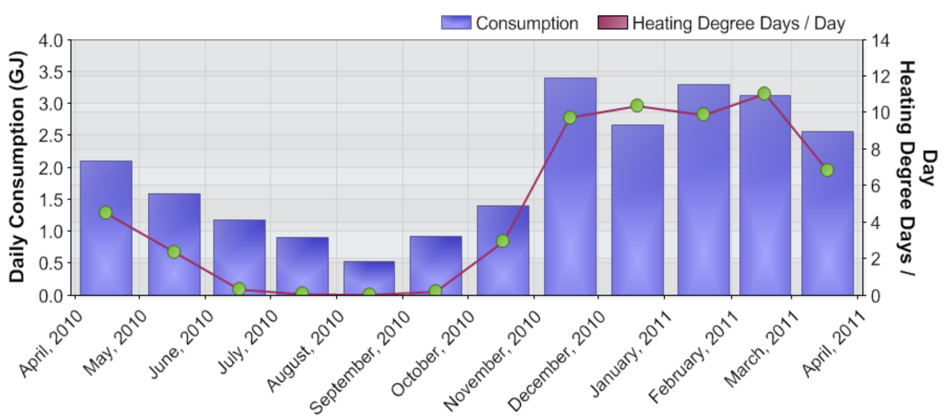


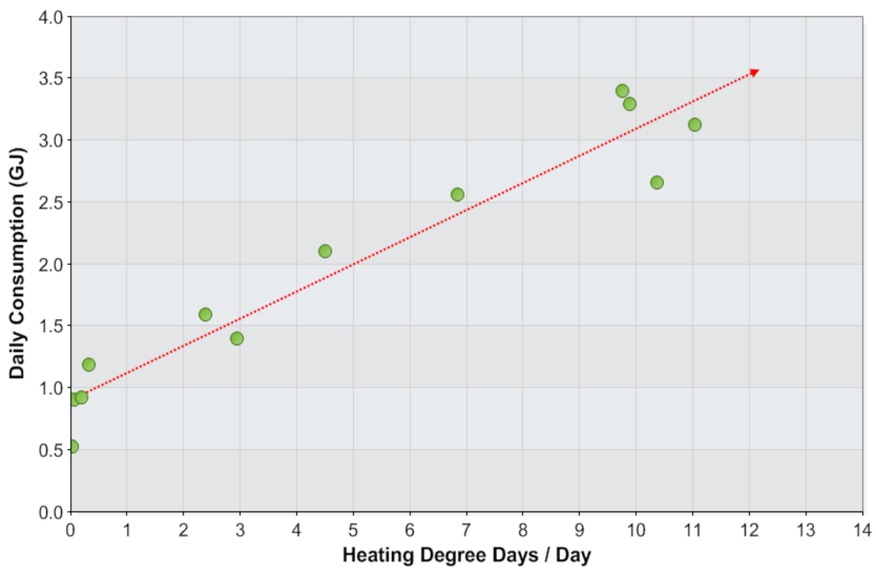
Model Analysis

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0010-721055 - 5440-201 A Street**
Meter: **721055-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption | **Selected As:** 2012259's Baseline | **Base Period:** 2010-03-31 to 2011-03-31 | **Base Load:** 0.906 GJ / Day | **R^2:** 0.930 | **CV(RMSE):** 14.37

NDB: 0 | **Parameter:** Daily Temperature | **Balance Point:** 14.00 | **Weather Factor:** 0.219 GJ / HDD | **P-Value:** 100.00%





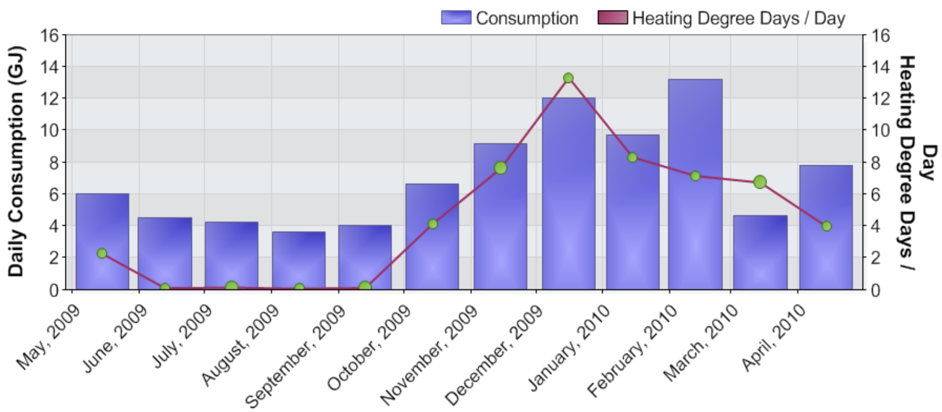
Start Date	End Date	Days	Consumption GJ	Consumption GJ / Day	HDDs / Day	Baseline GJ	Deviation %
2010-03-31	2010-04-30	31.00	65.10	2.100	4.50	58.64	11
2010-05-01	2010-06-01	32.00	51.00	1.594	2.38	45.69	12
2010-06-02	2010-06-30	29.00	34.40	1.186	0.32	28.33	21
2010-07-01	2010-07-30	30.00	27.00	0.900	0.06	27.57	-2
2010-07-31	2010-08-31	32.00	16.70	0.522	0.03	29.21	-43
2010-09-01	2010-09-30	30.00	27.60	0.920	0.20	28.52	-3
2010-10-01	2010-11-02	33.00	46.20	1.400	2.94	51.16	-10
2010-11-03	2010-12-01	29.00	98.50	3.397	9.75	88.24	12
2010-12-02	2011-01-04	34.00	90.40	2.659	10.37	108.12	-16
2011-01-05	2011-02-01	28.00	92.20	3.293	9.88	86.00	7
2011-02-02	2011-03-02	29.00	90.60	3.124	11.04	96.46	-6
2011-03-03	2011-03-31	29.00	74.30	2.562	6.84	69.79	6

Model Analysis

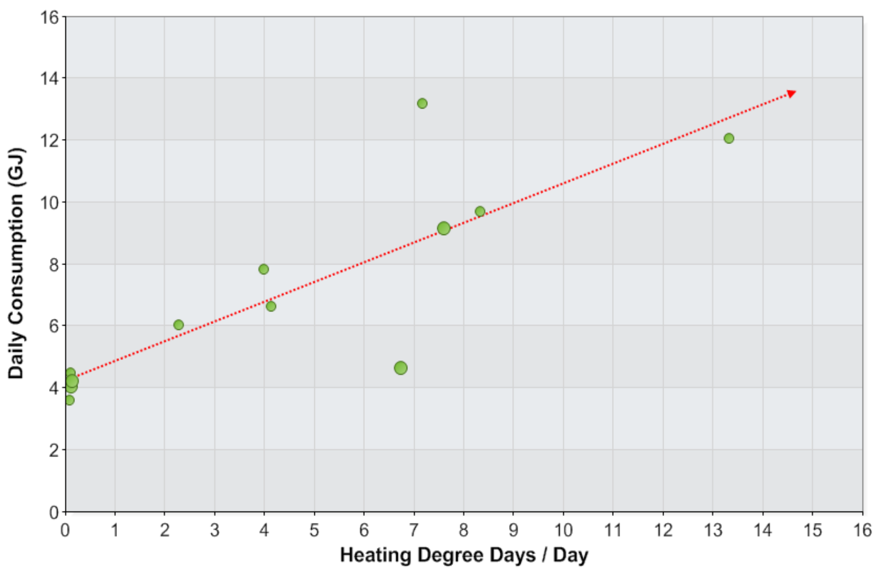
Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0001-763042 - 32101 Mt. Waddington Avenue**
Meter: **763042-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption | **Selected As:** 2012259's Baseline | **Base Period:** 2009-04-30 to 2010-04-28 | **Base Load:** 4.250 GJ / Day | **R^2:** 0.687 | **CV(RMSE):** 26.85

NDB: 0 | **Parameter:** Daily Temperature | **Balance Point:** 14.00 | **Weather Factor:** 0.637 GJ / HDD | **P-Value:** 99.95%



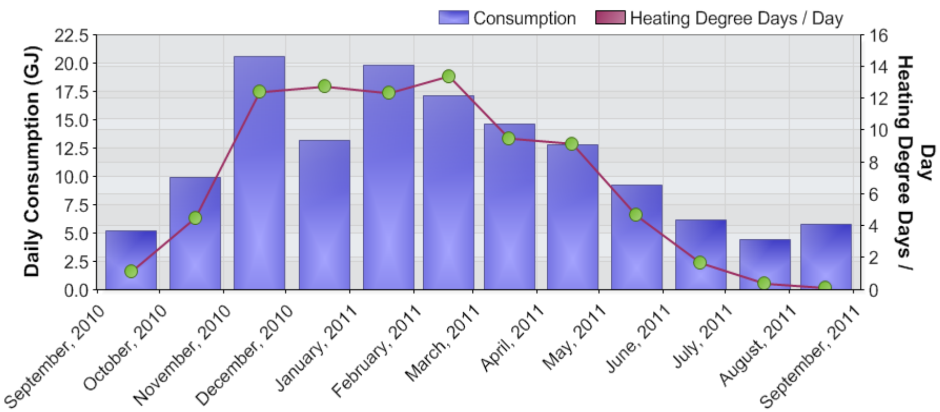
Start Date	End Date	Days	Consumption GJ	Consumption GJ / Day	Weight	HDDs / Day	Baseline GJ	Deviation %
2009-04-30	2009-05-28	29.00	174.9	6.031	0.956	2.27	165.2	6
2009-05-29	2009-06-26	29.00	130.4	4.497	0.956	0.10	125.2	4
2009-06-27	2009-07-29	33.00	139.0	4.212	1.088	0.14	143.1	-3
2009-07-30	2009-08-27	29.00	105.2	3.628	0.956	0.07	124.5	-16
2009-08-28	2009-09-28	32.00	129.4	4.044	1.055	0.11	138.3	-6
2009-09-29	2009-10-28	30.00	199.4	6.647	0.989	4.12	206.2	-3
2009-10-29	2009-11-30	33.00	302.2	9.158	1.088	7.60	300.1	1
2009-12-01	2009-12-30	30.00	362.0	12.067	0.989	13.31	382.1	-5
2009-12-31	2010-01-28	29.00	282.0	9.724	0.956	8.32	277.1	2
2010-01-29	2010-02-26	29.00	382.8	13.200	0.956	7.15	255.4	50
2010-02-27	2010-03-29	31.00	143.3	4.623	1.022	6.73	264.7	-46
2010-03-30	2010-04-28	30.00	234.8	7.827	0.989	3.97	203.5	15



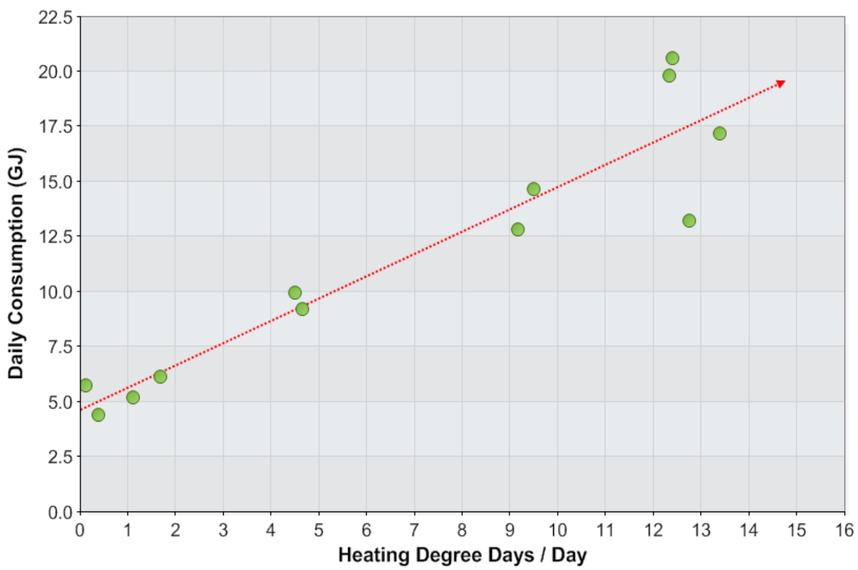
Model Analysis

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0003-743213 - 2575 Ware Street**
Meter: **743213-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption
NDB: 0
Selected As: 2012259's Baseline
Parameter: Daily Temperature
Base Period: 2010-09-02 to 2011-09-01
Balance Point: 15.50
Base Load: 4.641 GJ / Day
Weather Factor: 1.013 GJ / HDD
R^2: 0.882
P-Value: 100.00%
CV(RMSE): 17.80



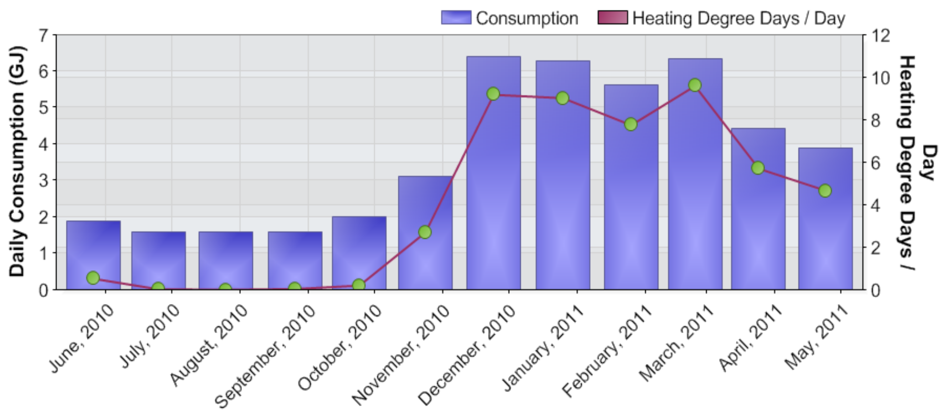
Start Date	End Date	Days	Consumption		HDDs / Day	Baseline	Deviation
			GJ	GJ / Day		GJ	%
2010-09-02	2010-10-01	30.00	154.8	5.16	1.12	173.3	-11
2010-10-02	2010-11-02	32.00	317.5	9.92	4.51	294.7	8
2010-11-03	2010-12-02	30.00	617.2	20.57	12.39	515.9	20
2010-12-03	2011-01-04	33.00	436.0	13.21	12.75	579.5	-25
2011-01-05	2011-02-02	29.00	574.7	19.82	12.33	496.9	16
2011-02-03	2011-03-03	29.00	497.6	17.16	13.40	528.3	-6
2011-03-04	2011-04-01	29.00	424.9	14.65	9.49	413.5	3
2011-04-02	2011-05-03	32.00	409.4	12.79	9.16	445.5	-8
2011-05-04	2011-06-02	30.00	276.0	9.20	4.66	280.8	-2
2011-06-03	2011-07-04	32.00	196.3	6.13	1.68	202.8	-3
2011-07-05	2011-08-03	30.00	132.0	4.40	0.38	150.9	-13
2011-08-04	2011-09-01	29.00	166.2	5.73	0.11	137.8	21

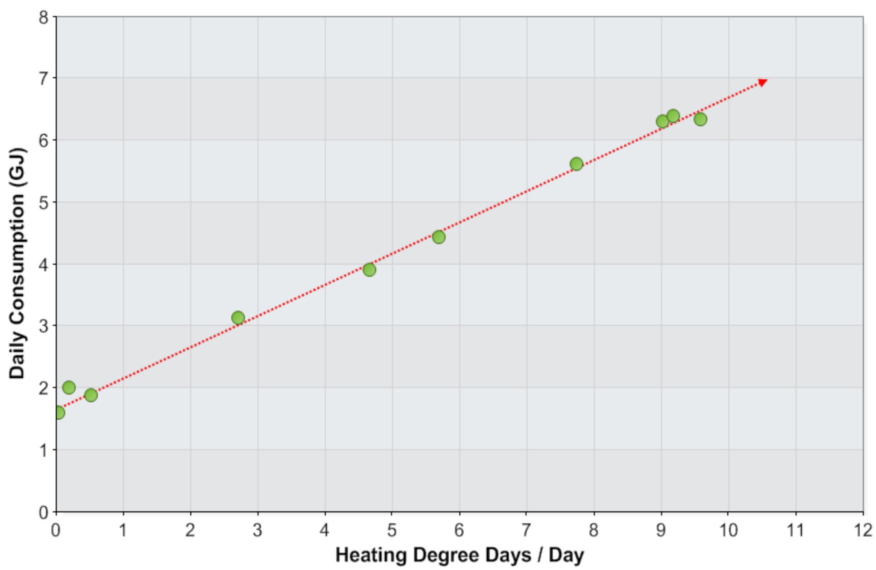


Model Analysis

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0005-713430 - 18 Jack Mahony Place**
Meter: **713430-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption **Selected As:** 2012259's Baseline **Base Period:** 2010-05-11 to 2011-05-09 **Base Load:** 1.654 GJ / Day **R²:** 0.997 **CV(RMSE):** 3.336
NDB: 0 **Parameter:** Daily Temperature **Balance Point:** 13.00 **Weather Factor:** 0.504 GJ / HDD **P-Value:** 100.00%



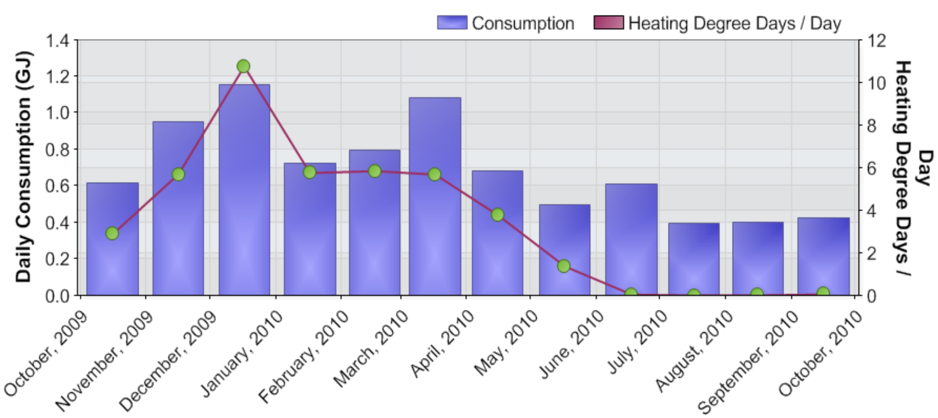


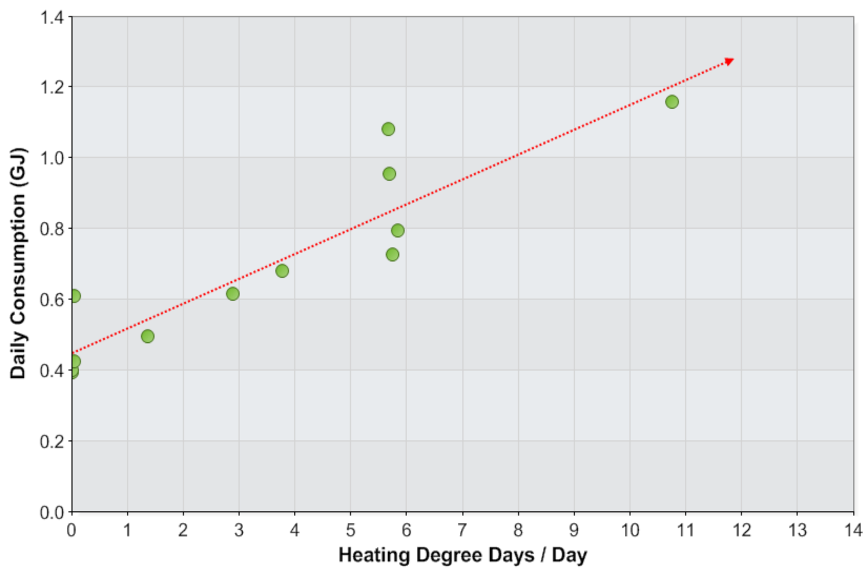
Start Date	End Date	Days	Consumption GJ	Consumption GJ / Day	HDDs / Day	Baseline GJ	Deviation %
2010-05-11	2010-06-09	30.00	56.20	1.873	0.52	57.5	-2.3
2010-06-10	2010-07-08	29.00	46.30	1.597	0.03	48.4	-4.3
2010-07-09	2010-08-10	33.00	52.70	1.597	0.00	54.6	-3.4
2010-08-11	2010-09-09	30.00	48.00	1.600	0.04	50.2	-4.4
2010-09-10	2010-10-07	28.00	56.00	2.000	0.20	49.1	14.0
2010-10-08	2010-11-08	32.00	100.00	3.125	2.70	96.5	3.6
2010-11-09	2010-12-08	30.00	191.70	6.390	9.18	188.5	1.7
2010-12-09	2011-01-10	33.00	207.70	6.294	9.02	204.7	1.5
2011-01-11	2011-02-08	29.00	162.90	5.617	7.75	161.3	1.0
2011-02-09	2011-03-09	29.00	183.80	6.338	9.59	188.3	-2.4
2011-03-10	2011-04-07	29.00	128.40	4.428	5.70	131.3	-2.2
2011-04-08	2011-05-09	32.00	124.90	3.903	4.67	128.2	-2.6

Model Analysis

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0006-471682 - 1678 W. 7th Avenue**
Meter: **471682-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption **Selected As:** 2012259's Baseline **Base Period:** 2009-10-01 to 2010-09-30 **Base Load:** 0.449 GJ / Day **R²:** 0.832 **CV(RMSE):** 16.11
NDB: 0 **Parameter:** Daily Temperature **Balance Point:** 13.00 **Weather Factor:** 0.0702 GJ / HDD **P-Value:** 100.00%





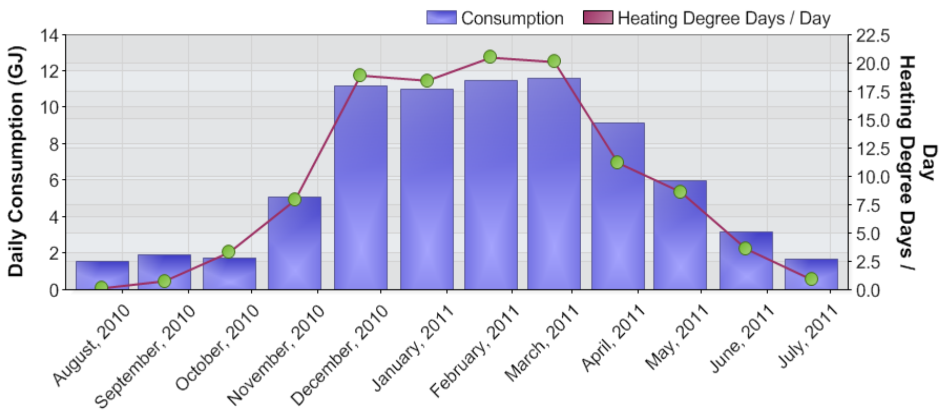
Start Date	End Date	Days	Consumption GJ	Consumption GJ / Day	HDDs / Day	Baseline GJ	Deviation %
2009-10-01	2009-10-30	30.00	18.50	0.617	2.88	19.54	-5
2009-10-31	2009-12-01	32.00	30.50	0.953	5.69	27.16	12
2009-12-02	2009-12-31	30.00	34.70	1.157	10.75	36.13	-4
2010-01-01	2010-02-01	32.00	23.20	0.725	5.75	27.29	-15
2010-02-02	2010-03-02	29.00	23.00	0.793	5.84	24.92	-8
2010-03-03	2010-03-30	28.00	30.30	1.082	5.68	23.74	28
2010-03-31	2010-04-30	31.00	21.10	0.681	3.77	22.13	-5
2010-05-01	2010-06-01	32.00	15.80	0.494	1.37	17.44	-9
2010-06-02	2010-07-02	31.00	18.90	0.610	0.05	14.02	35
2010-07-03	2010-07-30	28.00	11.00	0.393	0.00	12.57	-13
2010-07-31	2010-08-31	32.00	12.80	0.400	0.01	14.39	-11
2010-09-01	2010-09-30	30.00	12.70	0.423	0.05	13.58	-6

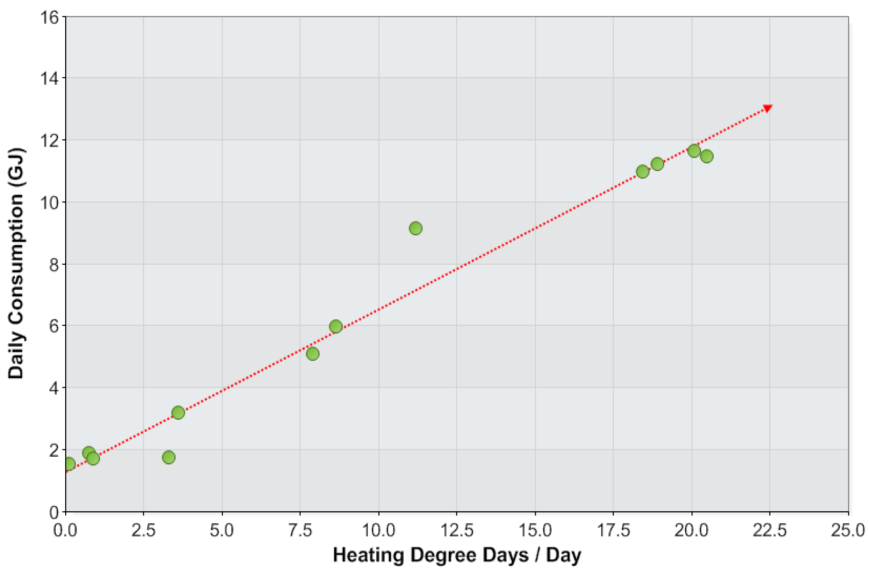
Model Analysis

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0007-59502 - 712 Sahali Terrace**
Meter: **59502-GAS-01**
Model: **Htg Pre - 12 months (Linear)**

Category: Consumption | **Selected As:** 2012259's Baseline | **Base Period:** 2010-07-07 to 2011-07-06 | **Base Load:** 1.293 GJ / Day | **R^2:** 0.970 | **CV(RMSE):** 12.35

NDB: 0 | **Parameter:** Daily Temperature | **Balance Point:** 17.50 | **Weather Factor:** 0.525 GJ / HDD | **P-Value:** 100.00%





Start Date	End Date	Days	Consumption		HDDs / Day	Baseline	Deviation
			GJ	GJ / Day		GJ	%
2010-07-07	2010-08-05	30.00	46.0	1.533	0.13	40.8	12.7
2010-08-06	2010-09-03	29.00	55.1	1.900	0.76	49.0	12.4
2010-09-04	2010-10-05	32.00	56.1	1.753	3.29	96.7	-42.0
2010-10-06	2010-11-04	30.00	152.4	5.080	7.89	163.0	-6.5
2010-11-05	2010-12-06	32.00	358.9	11.216	18.91	359.1	-0.1
2010-12-07	2011-01-06	31.00	340.4	10.981	18.45	340.5	0.0
2011-01-07	2011-02-04	29.00	332.6	11.469	20.49	349.5	-4.8
2011-02-05	2011-03-07	31.00	360.7	11.635	20.10	367.2	-1.8
2011-03-08	2011-04-05	29.00	264.8	9.131	11.20	208.0	27.3
2011-04-06	2011-05-05	30.00	179.1	5.970	8.64	174.9	2.4
2011-05-06	2011-06-06	32.00	101.9	3.184	3.61	102.0	-0.1
2011-06-07	2011-07-06	30.00	51.0	1.700	0.88	52.7	-3.2

APPENDIX C: LAST READING DATES

Last Reading Dates

Project: **FortisBC - Fireplace Timers Pilot (2012259)**

Site		Meter					Last Reading				
Name	Code	Name	Description	Type	Account Number	Premise ID	Date	Days	Consumption	Cost	Days Since
FTP0008-291374		291374-GAS-01		Natural Gas		291374	2012-04-26	31	134	0	209
FTP0009-486157		486157-GAS-01		Natural Gas		486157	2012-11-01	30	416	0	20
FTP0010-721055		721055-GAS-01		Natural Gas		721055	2012-05-01	33	64	0	204
FTP0017-307213		307213-GAS-01		Natural Gas		307213	2012-04-30	30	1,172	0	205
FTPP0001-763042		763042-GAS-01		Natural Gas		763042	2012-04-27	30	218	0	208
FTPP0003-743213		743213-GAS-01		Natural Gas		743213	2012-10-31	30	262	0	21
FTPP0005-713430		713430-GAS-01		Natural Gas		713430	2012-05-07	32	110	0	198
FTPP0006-471682		471682-GAS-01		Natural Gas		471682	2012-04-30	32	22	0	205
FTPP0007-59502		59502-GAS-01		Natural Gas		59502	2012-11-02	30	186	0	19

APPENDIX D: SURVEY QUESTIONS

Project 2012259 Fireplace Timer Pilot Project, Client: FortisBC, Cindy Wong

Building information

Building address	Confirm					
Number of dwelling units	Confirm					
How many dwelling units have fireplaces?	Confirm					
Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.		sq.ft				

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)		
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)		
Do you have boilers for heating in your building	Yes	No				
Have you had any repairs or replacement of boilers within the last 5 years?	yes	When?	no			
Are you aware of a boiler shutdown during summer	Yes	No	I don't know			
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)		
Have you had any repair or replacement of the domestic hot water equipment?	Yes	When?	No		new boilers	
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know			
How is the heating of the Make Up Air Units provided	Gas fired	Heating Coil with hot water from boiler	Electric	I don't know	Other (please specify)	
Are you aware of a shut down of the heating system in the Make Up Air Unit during Summer	Yes	No	I don't know			
Have you had any repair or replacement of the the Make Up Air Unit?	Yes	When?	No			
Do you have gas stoves in the dewlling units?	Yes	No				
Other gas consuming equipment in the building:						

Fireplace Survey

Was the installation of the fireplace timer well received by the occupants?	Yes	No	I don't know	Other (please specify)		
How long did it take to install all fireplace timer	few days	one week	two weeks	three weeks	one month	longer than one month
Any complaints about the fireplace timer						
Any positive feedback regarding the fireplace timer	not bothered					
With you current knowledge would you install fireplace timers if you had to make the decision again	Yes	No	Reason:			
Did the fireplace timer make it easier to start up the fireplace?	Yes	No	I don't know			
Did the occupants use their fireplaces more often since the timer was installed?	the same	more often	less	I don't know		

FortisBC Standard Satisfaction Questions (the following questions are being asked in all our program surveys in this format so we can do an overall comparison between programs)

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with the overall service provided by FortisBC?

1	2	3	4	5	6	7	8	9	10

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with FortisBC's Fireplace Timer Pilot overall?

1	2	3	4	5	6	7	8	9	10

How satisfied are you with each of the following aspects of the Fireplace Timer Pilot?

1	2	3	4	5	6	7	8	9	10

Ease of obtaining information on the program/pilot

Ease of completing the application form/program requirements

Program deadlines

FortisBC staff who took your order request and scheduled your work

APPENDIX E: SURVEY RESULTS

FTPP0001, Roderic Hurry, 32101 Mt. Waddington Av, Abbotsford

Building address	Confirmed				
Number of dwelling units	Confirmed				
How many dwelling units have fireplaces?	Confirmed				
Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.	70,620	sq.ft			

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)	
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)	
Do you have boilers for heating in your building	Yes	No			
Have you had any repairs or replacement of boilers within the last 5 years?	yes	2009	no		
Are you aware of a boiler shutdown during summer	Yes	No	I don't know		
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)	
Have you had any repair or replacement of the domestic hot water equipment?	Yes	2009	No		
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know		
How is the heating of the Make Up Air Units provided	Gas fired	Heating Coil with hot water from boiler	Electric	I don't know	Other (please specify)
Are you aware of a shut down of the heating system in the Make Up Air Unit during Summer	Yes	No	I don't know		
Have you had any repair or replacement of the the Make Up Air Unit?	Yes	When?	No		
Do you have gas stoves in the dewlling units?	Yes	No			
Other gas consuming equipment in the building:	Insuite Fireplaces				
Did you experience any major repairs or problems with gas consuming equipment between end of 2008 and beginning of 2009?	Yes, replacement of gas fired DHW Tanks in 2009. Maybe also replacement of heating boiler as indicated by Katie but she also said that suites have electric baseboard heaters. Information provided by Katie might not be accurate.				

Fireplace Survey

Was the installation of the fireplace timer well received by the occupants?	Yes	No	I don't know	Other (please specify)	
How long did it take to install all fireplace timer	1 day	one week	two weeks	three weeks	one month
Any complaints about the fireplace timer	yes, gets too cold at night				
Any positive feedback regarding the fireplace timer					
Did the fireplace timer make it easier to start up the fireplace?	Yes	No	I don't know		
Did the occupants use their fireplaces more often since the timer was installed?	the same	more often	less	I don't know	

FTP0009, 3766 West 7th Ave., Vancouver

Building address	Confirmed					
Number of dwelling units	Confirmed					
How many dwelling units have fireplaces?	Confirmed					
Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.	not available	sq.ft	Property Manager was not familiar with the building and answers might be incorrect !			

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)	Property Manager was unsure about the heating system	
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)		
~~Do you have boilers for heating in your building~~	~~0~~	~~1~~	~~2~~	~~more than 2~~		
~~Have you had any repairs or replacement of boilers within the last 5 years?~~	~~yes~~	~~When?~~	~~no~~			
~~Are you aware of a boiler shutdown during summer~~	~~Yes~~	~~No~~	~~I don't know~~			
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)		
Have you had any repair or replacement of the domestic hot water equipment?	Yes	When?	Don't Know			
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know			
How is the heating of the Make Up Air Units provided	Gas fired	Heating Coil with hot water from boiler	Electric	I don't know	Other (please specify)	
Are you aware of a shut down of the heating system in the Make Up Air Unit during Summer	Yes	No	I don't know			
Have you had any repair or replacement of the the Make Up Air Unit?	Yes	No	I don't know			
Do you have gas stoves in the dewlling units?	Yes	No	I don't know			
Other gas consuming equipment in the building:						

Fireplace Survey => was not able to provide any answers to any of the questions below

Was the installation of the fireplace timer well received by the occupants?	Yes	No	I don't know	Other (please specify)		
How long did it take to install all fireplace timer	few days	one week	two weeks	three weeks	one month	longer than one month
Any complaints about the fireplace timer						
Any positive feedback regarding the fireplace timer						
With you current knowledge would you install fireplace timers if you had to make the decision again	Yes	No	Reason:			
Did the fireplace timer make it easier to start up the fireplace?	Yes	No	I don't know			
Did the occupants use their fireplaces more often since the timer was installed?	the same	more often	less	I don't know		

FTPP0007, Diane Chen, 712 Sahali Terrace, Kamloops

Building address	Confirmed
Number of dwelling units	Confirmed
How many dwelling units have fireplaces?	Confirmed

Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.	59000 gross living area 84,000 Total Heated Floor Area	sq.ft	some FP already had timer when installed

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)	
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)	
Do you have boilers for heating in your building	Yes	No			(Comment Property Manger seems to
Have you had any repairs or replacement of boilers within the last 5 years?	yes	When?	no		be not technical/familiar with building)
Are you aware of a boiler shutdown during summer	Yes	No	I don't know		
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)	Electric DHW tanks in the suites
Have you had any repair or replacement of the domestic hot water equipment?	Yes	When?	No		
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know		
How is the heating of the Make Up Air Units provided	Gas fired	Heating Coil with hot water from boiler	Electric	I don't know	Other (please specify)
Are you aware of a shut down of the heating system in the Make Up Air Unit during Summer	Yes	No	I don't know		
Have you had any repair or replacement of the the Make Up Air Unit?	Yes	When?	No		
Do you have gas stoves in the dewlling units?	Yes	No			
Other gas consuming equipment in the building:	No				

Fireplace Survey

Was the installation of the fireplace timer well received by the occupants?	Yes	No	I don't know	Other (please specify)		
How long did it take to install all fireplace timer	few days	one week	two weeks	three weeks	one month	longer than one month
Any complaints about the fireplace timer	N/A					
Any positive feedback regarding the fireplace timer	N/A					
Did the fireplace timer make it easier to start up the fireplace?	Yes	No	I don't know			
Did the occupants use their fireplaces more often since the timer was installed?	the same	more often	less	I don't know		

FTPP0006, Danielle Huff, 1678 W. 7th Avenue, Vancouver

Building address	Confirmed (spoke to Danielle Huff, danielle_huff@telus.net)					
Number of dwelling units	Confirmed					
How many dwelling units have fireplaces?	Confirmed					
Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.	10,600	sq.ft				

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)		
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)		
Do you have boilers for heating in your building	0	1	2	more than 2		
~~Have you had any repairs or replacement of boilers within the last 5 years?~~	~~yes~~	~~When?~~	~~no~~			
~~Are you aware of a boiler shutdown during summer~~	~~Yes~~	~~No~~	~~I don't know~~			
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)		
Have you had any repair or replacement of the domestic hot water equipment?	Yes	When?	No			
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know			
~~How is the heating of the Make Up Air Units provided~~	~~Gas fired~~	~~Heating Coil with hot water from boiler~~	~~Electric~~	~~I don't know~~	~~Other (please specify)~~	
~~Are you aware of a shut down of the heating system in the Make Up Air Unit during Summer~~	~~Yes~~	~~No~~	~~I don't know~~			
~~Have you had any repair or replacement of the the Make Up Air Unit?~~	~~Yes~~	~~When?~~	~~No~~			
Do you have gas stoves in the dewlling units?	Yes	No				
Other gas consuming equipment in the building:	Fireplace are the only gas consuming equipment in the building					

Fireplace Survey

Was the installation of the fireplace timer well received by the occupants?	Yes	No	I don't know	Indifferent		
How long did it take to install all fireplace timer	one day	one week	two weeks	three weeks	one month	longer than one month
Any complaints about the fireplace timer	no					
Any positive feedback regarding the fireplace timer	some					
With you current knowledge would you install fireplace timers if you had to make the decision again	Yes	No	Reason: problems during installation			
Did the fireplace timer make it easier to start up the fireplace?	Yes	No	I don't know			
Did the occupants use their fireplaces more often since the timer was installed?	the same	more often	less	I don't know		

FTPP0003, Care Taker in Building, 2585 Ware Street, Abbotsford

Building address	Confirmed (two buildings, 2585 Ware Street and 2575 Ware Street)					
Number of dwelling units	Confirmed					
How many dwelling units have fireplaces?	Confirmed					
Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.	88,000	sq.ft				

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)		
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)		
Do you have boilers for heating in your building	Yes	No				
~~Have you had any repairs or replacement of boilers within the last 5 years?~~	~~yes~~	~~When?~~	~~no~~			
~~Are you aware of a boiler shutdown during summer~~	~~Yes~~	~~No~~	~~I don't know~~			
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)		
Have you had any repair or replacement of the domestic hot water equipment?	Yes	When?	No	@ 2585 replacement of boiler in 2011 and @ 2575 replacement in 2009		
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know			
How is the heating of the Make Up Air Units provided	Gas fired	Heating Coil with hot water from boiler	Electric	I don't know	Other (please specify)	not heated
Are you aware of a shut down of the heating system in the Make Up Air Unit during Summer	Yes	No	I don't know			
Have you had any repair or replacement of the the Make Up Air Unit?	Yes	When?	No			
Do you have gas stoves in the dewlling units?	Yes	No				
Other gas consuming equipment in the building:	No					

Fireplace Survey

Was the installation of the fireplace timer well received by the occupants?	Yes	No	I don't know	Other (please specify)		
How long did it take to install all fireplace timer	few days	one week	two weeks	three weeks	one month	longer than one month
Any complaints about the fireplace timer	Older people did not want to be bothered with the installation					
Any positive feedback regarding the fireplace timer	Generally very well received					
With you current knowledge would you install fireplace timers if you had to make the decision again	Yes	No	Reason: Savings			
Did the fireplace timer make it easier to start up the fireplace?	Yes	No	I don't know			
Did the occupants use their fireplaces more often since the timer was installed?	the same	more often	less	I don't know		

FTPP005 Boon Sim, Property Manager (survey conducted during site visit

Building information

Building address	Confirmed					
Number of dwelling units	Confirmed					
How many dwelling units have fireplaces?	Confirmed					
Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.		sq.ft				

saving you energy

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)		
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)		
Do you have boilers for heating in your building	Yes	No				
Have you had any repairs or replacement of boilers within the last 5 years?	~~yes~~	~~When?~~	~~no~~			
Are you aware of a boiler shutdown during summer	~~Yes~~	~~No~~	~~I don't know~~			
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)		
Have you had any repair or replacement of the domestic hot water equipment?	Yes	When?	No	Townhomes have 3 boilers, Condos have 2 boilers Repair of one of the boiler was carried out in May 2011		
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know			
How is the heating of the Make Up Air Units provided	Gas fired	Heating Coil with hot water from boiler	Electric	I don't know	Other (please specify)	
Are you aware of a shut down of the heating system of the Make Up Air Unit during Summer	Yes	No	I don't know			
Have you had any repair or replacement of the the Make Up Air Unit?	Yes	When?	No	repair of burner in spring 2012		
Do you have gas stoves in the dewlling units?	Yes	No				
Other gas consuming equipment in the building:	no					

Fireplace Survey

Was the installation of the fireplace timer well received by the occupants?	Generally Yes	No	I don't know	Other (please specify)		
How long did it take to install all fireplace timer	few days	one week	two weeks	three weeks	one month	longer than one month
Any complaints about the fireplace timer	Some of the timers did not work when they were installed. Electricians installed wall switches and hot tub timers as temporary solution until new timers were delivered					

FTPP0008, Alyson Huff – Caretaker

Building information

Building address	Confirmed
Number of dwelling units	Confirmed
How many dwelling units have fireplaces?	Confirmed

Total floor area of the building (dwelling units plus common area, exclusive underground parkade). If exact number is not available please provide your best estimation.	N/A	sq.ft

Building Equipment Survey

Base heating system in dwelling units	Electric Baseboard Heaters	Hydronic Baseboard Heaters	Radiant Heating System	Other (please specify)		
Heating control in dewlling units	Thermostats in Appartment	No Thermostats in Appartments	Manual Control/Valve on Baseboard Unit	Other (please specify)		
Do you have boilers for heating in your building	Yes	No				
Have you had any repairs or replacement of boilers within the last 5 years?	~~yes~~	~~When?~~	~~no~~			
Are you aware of a boiler shutdown during summer	~~Yes~~	~~No~~	~~I don't know~~			
How is domestic hot water provided?	Gas fired boiler	Gas fired domestic hot water tanks	Electric boiler	Other (please specify)		
Have you had any repair or replacement of the domestic hot water equipment?	Yes	When?	No	DHW Tanks were replaced in July 2008 and July 2011		
Do you have one or more Make Up Air Units for corridor pressurization?	Yes	No	I don't know			
How is the heating of the Make Up Air Units provided	Gas fired	Heating Coil with hot water from boiler	Electric	I don't know	No heating	
Are you aware of a shut down of the heating system of the Make Up Air Unit during Summer	Yes	No	I don't know			
Have you had any repair or replacement of the the Make Up Air Unit?	Yes	No	I don't know			
Do you have gas stoves in the dewlling units?	Yes	No				
Other gas consuming equipment in the building:						

Fireplace Survey

Was the installation of the fireplace timer well received by the occupants?	Yes	No	I don't know	Other (please specify)		
How long did it take to install all fireplace timer	few days	one week	two weeks	three weeks	one month	longer than one month
Any complaints about the fireplace timer	No					
Any positive feedback regarding the fireplace timer	No					
With you current knowledge would you install fireplace timers if you had to make the decision again	Yes	No	It is not my decision to make			
Did the fireplace timer make it easier to start up the fireplace?	Yes	No	I don't know			
Did the occupants use their fireplaces more often since the timer was installed?	the same	more often	less	I don't know		

FortisBC Standard Satisfaction Questions

FTPP0001, Roderic Hurry, 32101 Mt. Waddington Av, Abbotsford

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with the overall service provided by FortisBC?
1 2 3 4 5 6 7 8 9 10

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with FortisBC's Fireplace Timer Pilot overall?
1 2 3 4 5 6 7 8 9 10

How satisfied are you with each of the following aspects of the Fireplace Timer Pilot?
1 2 3 4 5 6 7 8 9 10 N/A
Ease of obtaining information on the program/pilot
Ease of completing the application form/program requirements
Program deadlines
FortisBC staff who took your order request and scheduled your work

FTPP0003, Care Taker in Building, 2585 Ware Street, Abbotsford

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with the overall service provided by FortisBC?
1 2 3 4 5 6 7 8 9 10

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with FortisBC's Fireplace Timer Pilot overall?
1 2 3 4 5 6 7 8 9 10

How satisfied are you with each of the following aspects of the Fireplace Timer Pilot?
1 2 3 4 5 6 7 8 9 10
Ease of obtaining information on the program/pilot 10
Ease of completing the application form/program requirements
Program deadlines 10
FortisBC staff who took your order request and scheduled your work 10

FTPP0006, Danielle Huff, 1678 W. 7th Avenue, Vancouver

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with the overall service provided by FortisBC?
1 2 3 4 5 6 7 8 9 10

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with FortisBC's Fireplace Timer Pilot overall?
1 2 3 4 5 6 7 8 9 10 Problems with installation (Burner replacement)

How satisfied are you with each of the following aspects of the Fireplace Timer Pilot?
1 2 3 4 5 6 7 8 9 10 N/A
Ease of obtaining information on the program/pilot
Ease of completing the application form/program requirements
Program deadlines
FortisBC staff who took your order request and scheduled your work

FTPP0007, Diane Chen, 712 Sahali Terrace, Kamloops

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with the overall service provided by FortisBC?

1 2 3 4 5 6 7 8 9 10

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with FortisBC's Fireplace Timer Pilot overall?

1 2 3 4 5 6 7 8 9 10

How satisfied are you with each of the following aspects of the Fireplace Timer Pilot?

1 2 3 4 5 6 7 8 9 10

Ease of obtaining information on the program/pilot	7	
Ease of completing the application form/program requirements	5	one application for each unit needed to be filled out
Program deadlines	8	
FortisBC staff who took your order request and scheduled your work	8	

FTP0009, 3766 West 7th Ave., Vancouver

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with the overall service provided by FortisBC?

1 2 3 4 5 6 7 8 9 10

Using a 10 point scale where 1 is "not at all satisfied" and 10 is "very satisfied, how satisfied are you with FortisBC's Fireplace Timer Pilot overall?

1 2 3 4 5 6 7 8 9 10

How satisfied are you with each of the following aspects of the Fireplace Timer Pilot?

1 2 3 4 5 6 7 8 9 10

Ease of obtaining information on the program/pilot

Ease of completing the application form/program requirements

Program deadlines

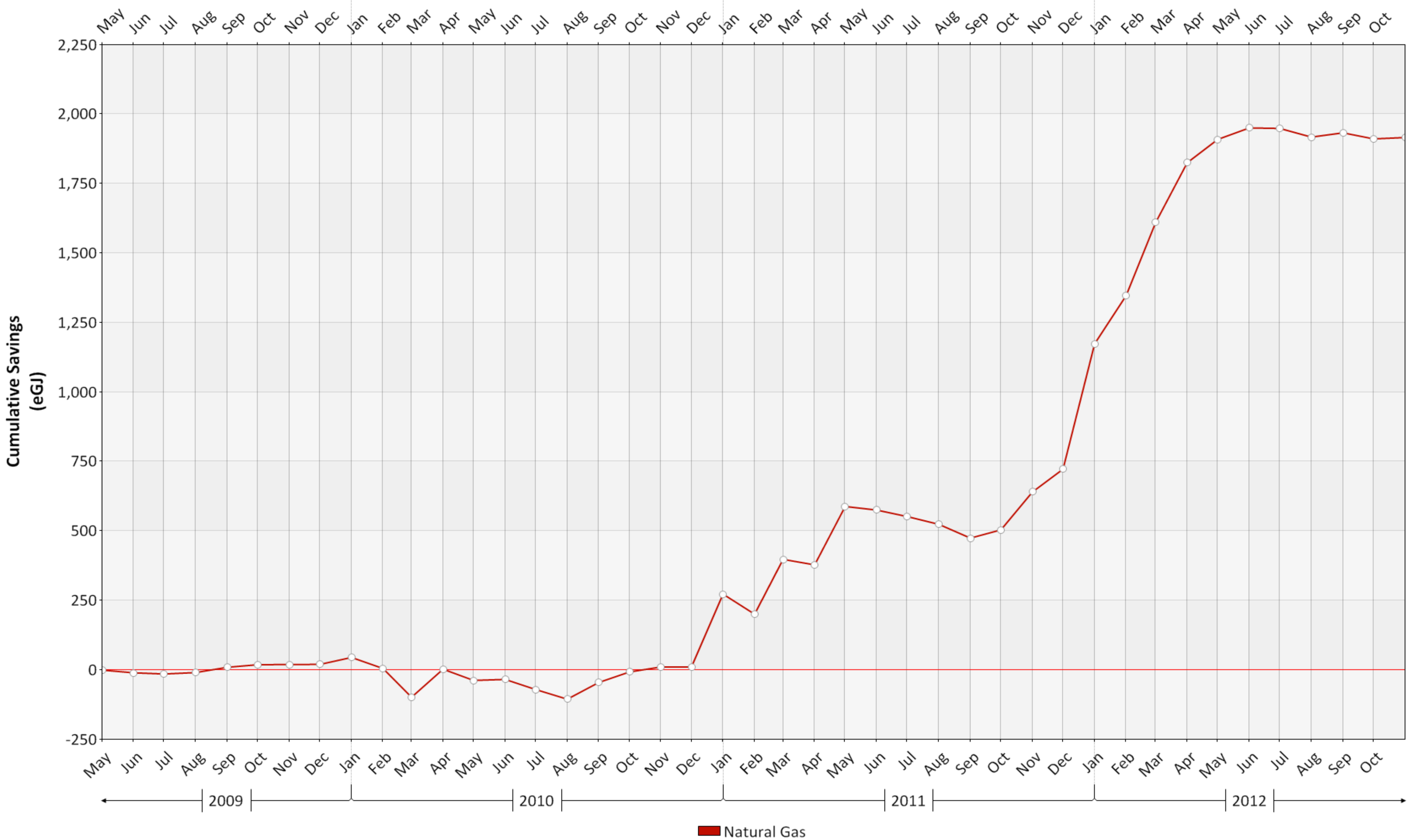
FortisBC staff who took your order request and scheduled your work

Property Manager took over building recently and was not able to provide answers to questions

APPENDIX F: CUSUM PROJECT

CUSUM: Project

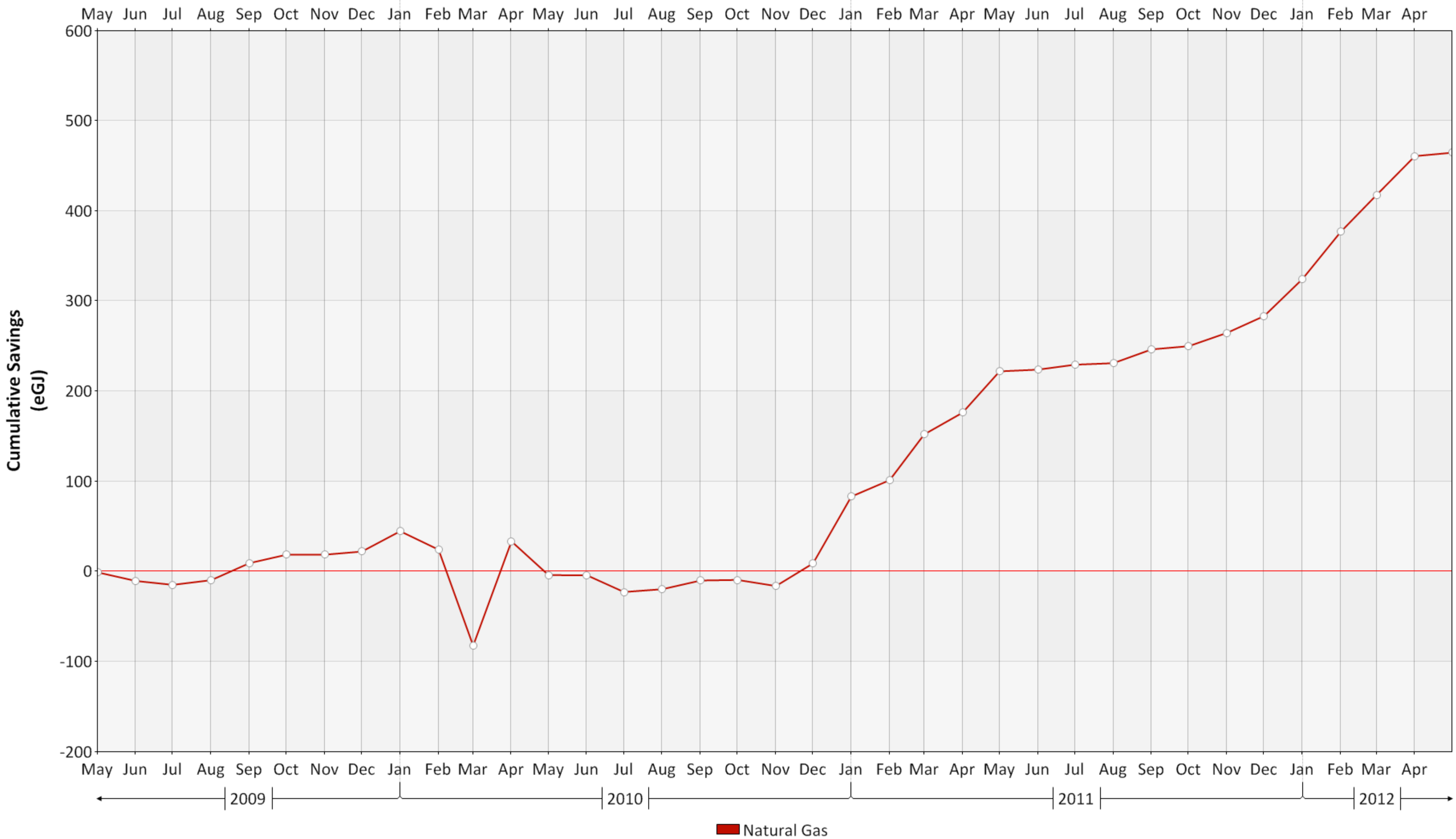
Project: **FortisBC - Fireplace Timers Pilot (2012259)**



APPENDIX G: CUSUM – SITE

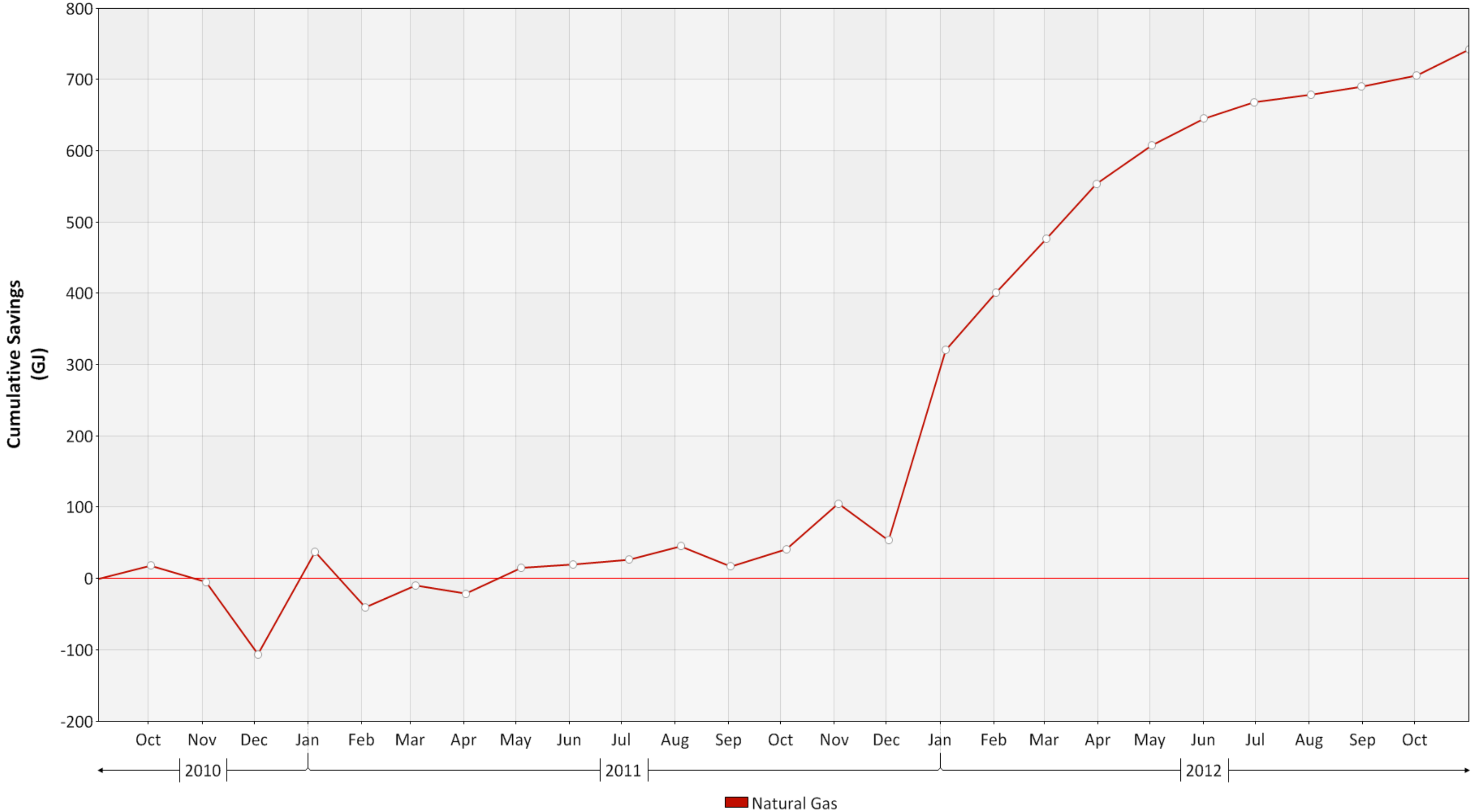
CUSUM: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0001-763042 - 32101 Mt. Waddington Avenue**



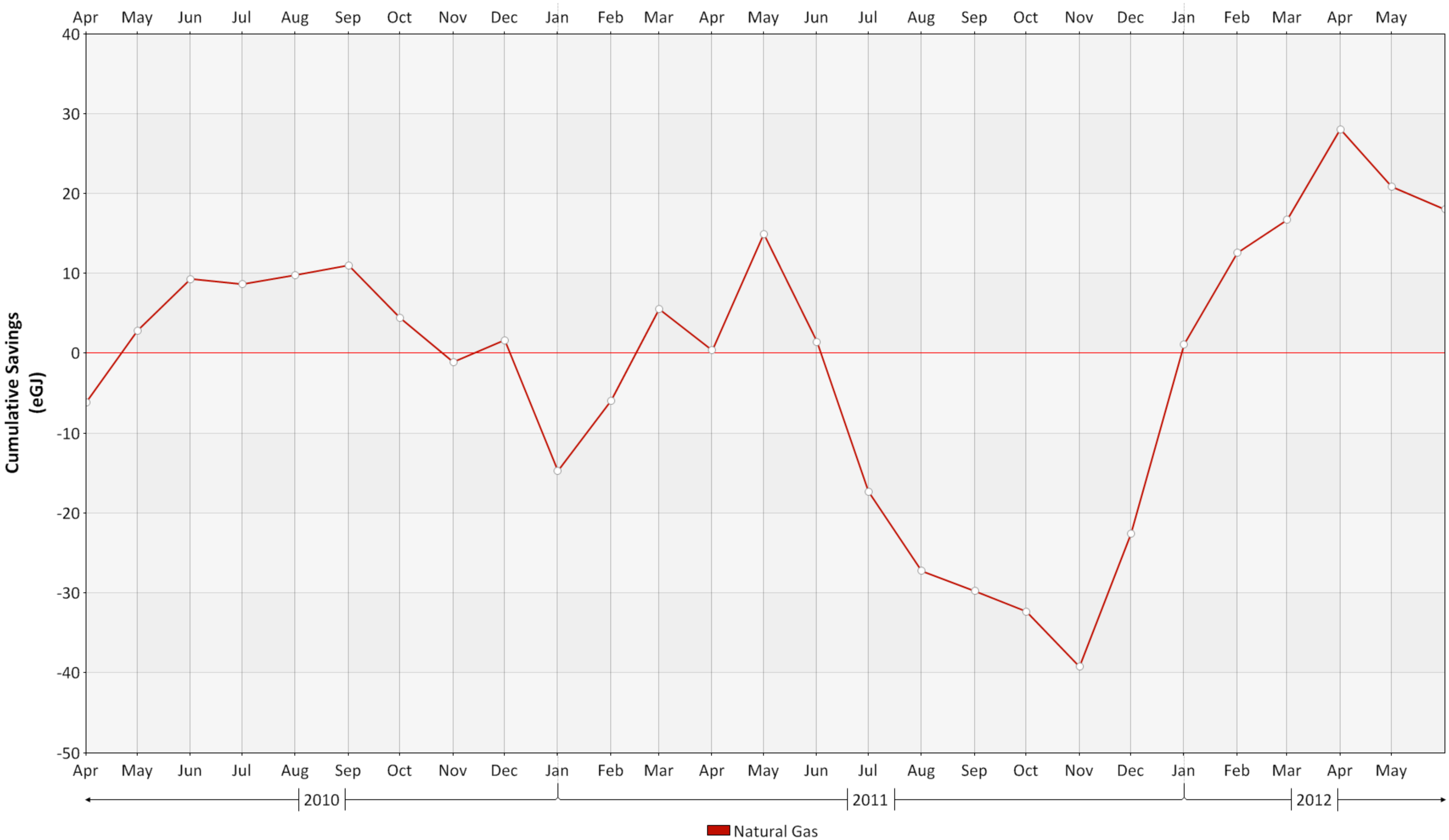
CUSUM: Meter

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0003-743213 - 2575 Ware Street**
Meter: **743213-GAS-01**



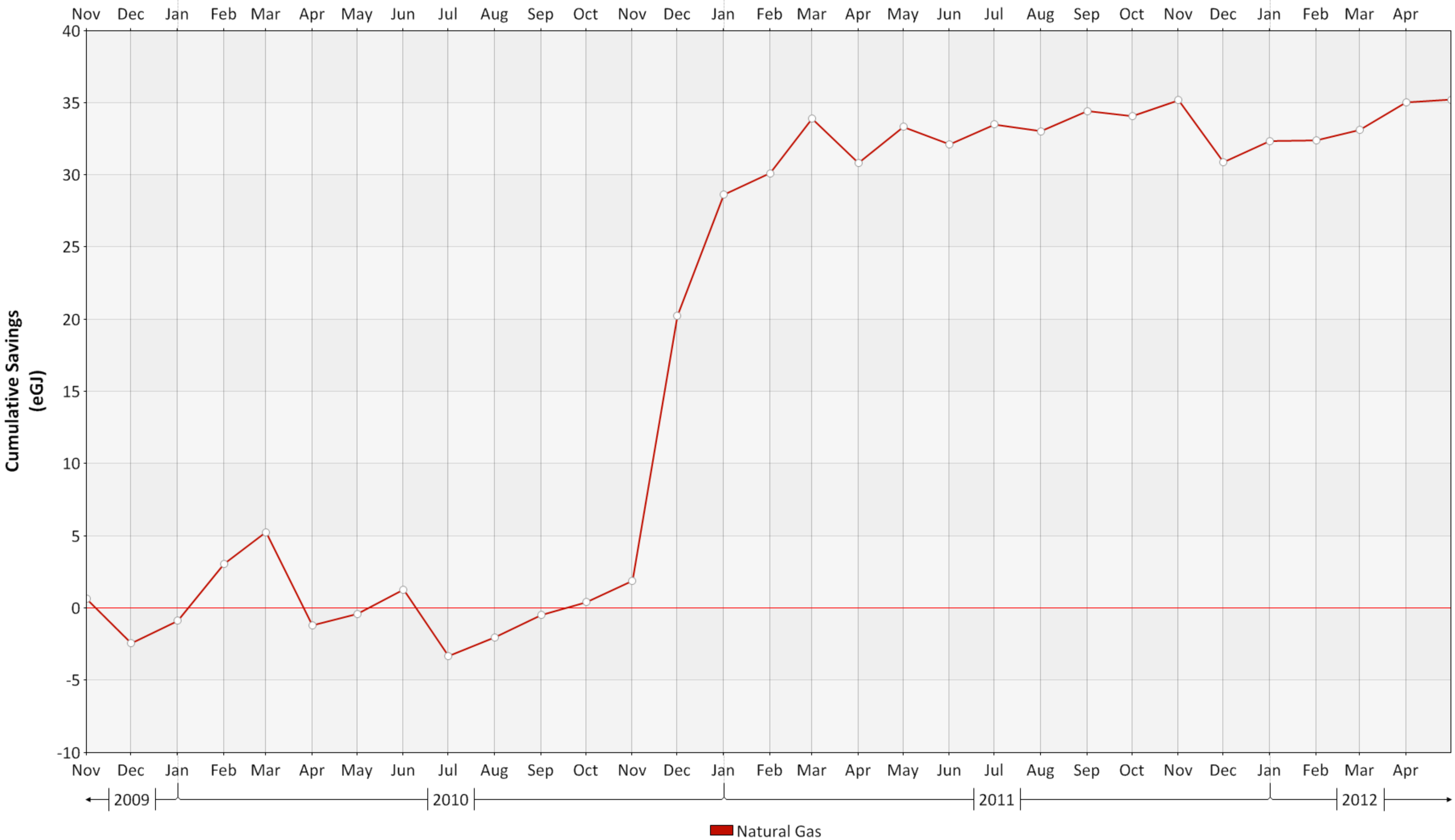
CUSUM: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0005-713430 - 18 Jack Mahony Place**



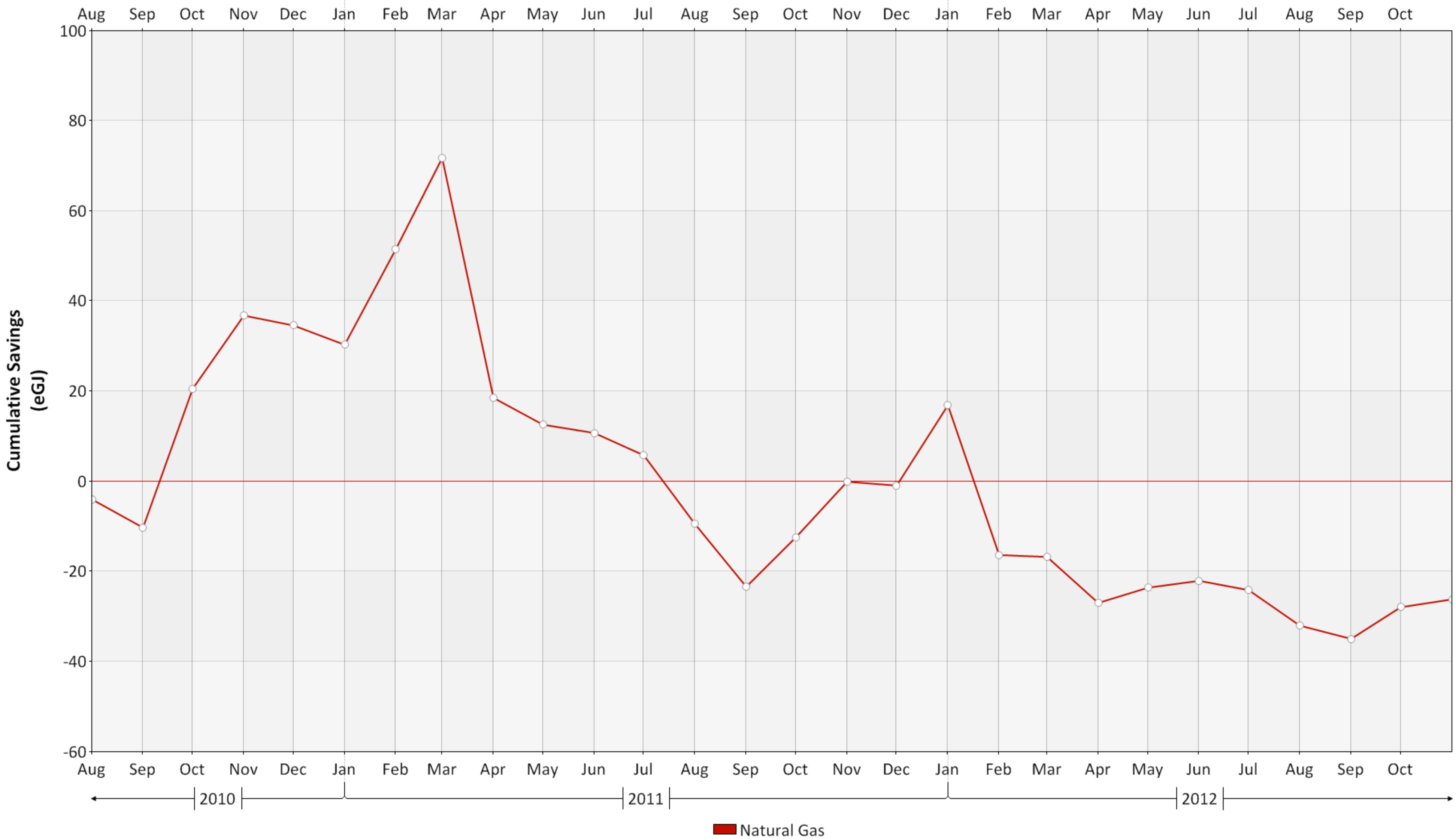
CUSUM: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0006-471682 - 1678 W. 7th Avenue**



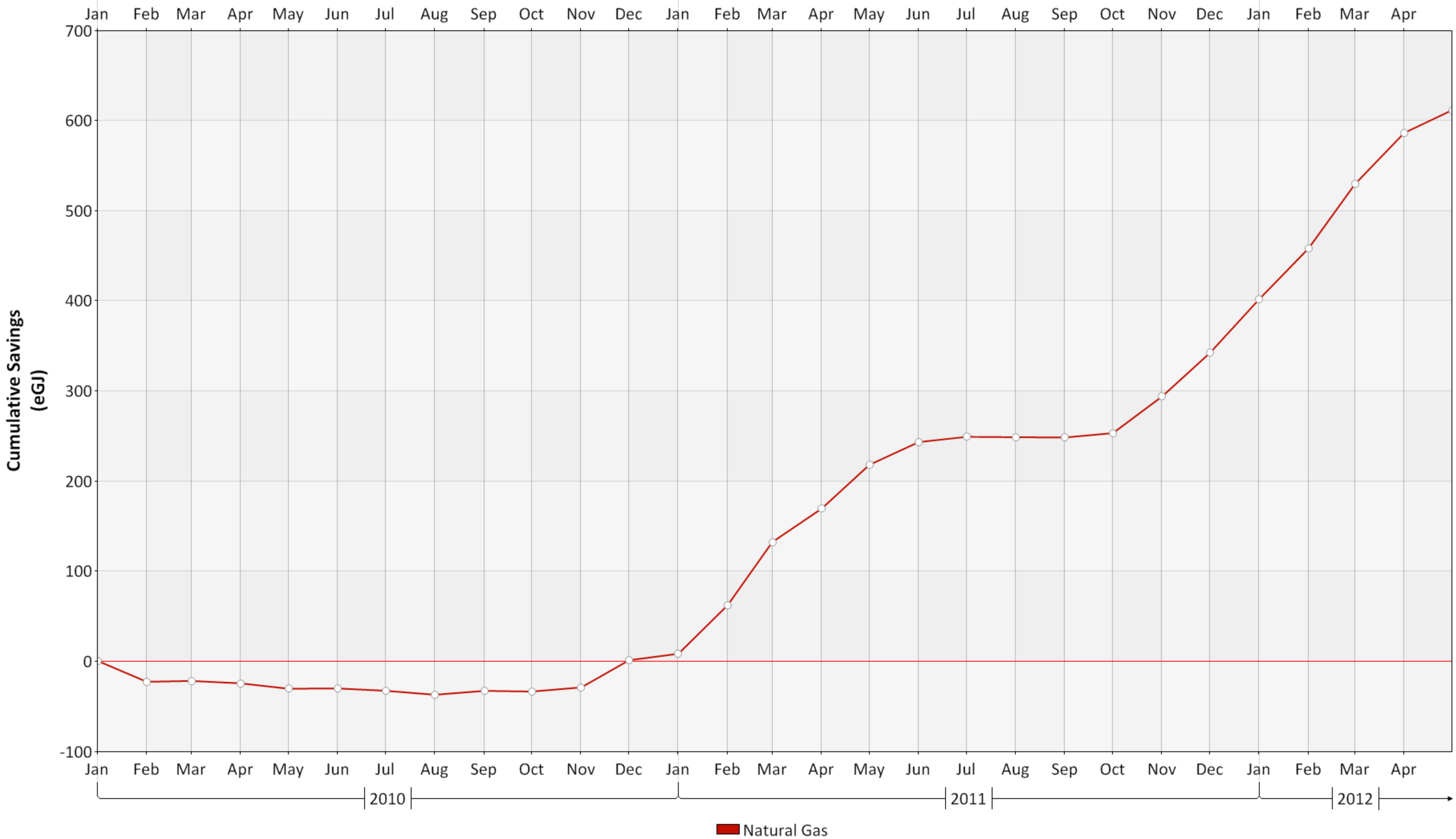
CUSUM: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0007-59502 - 712 Sahali Terrace**



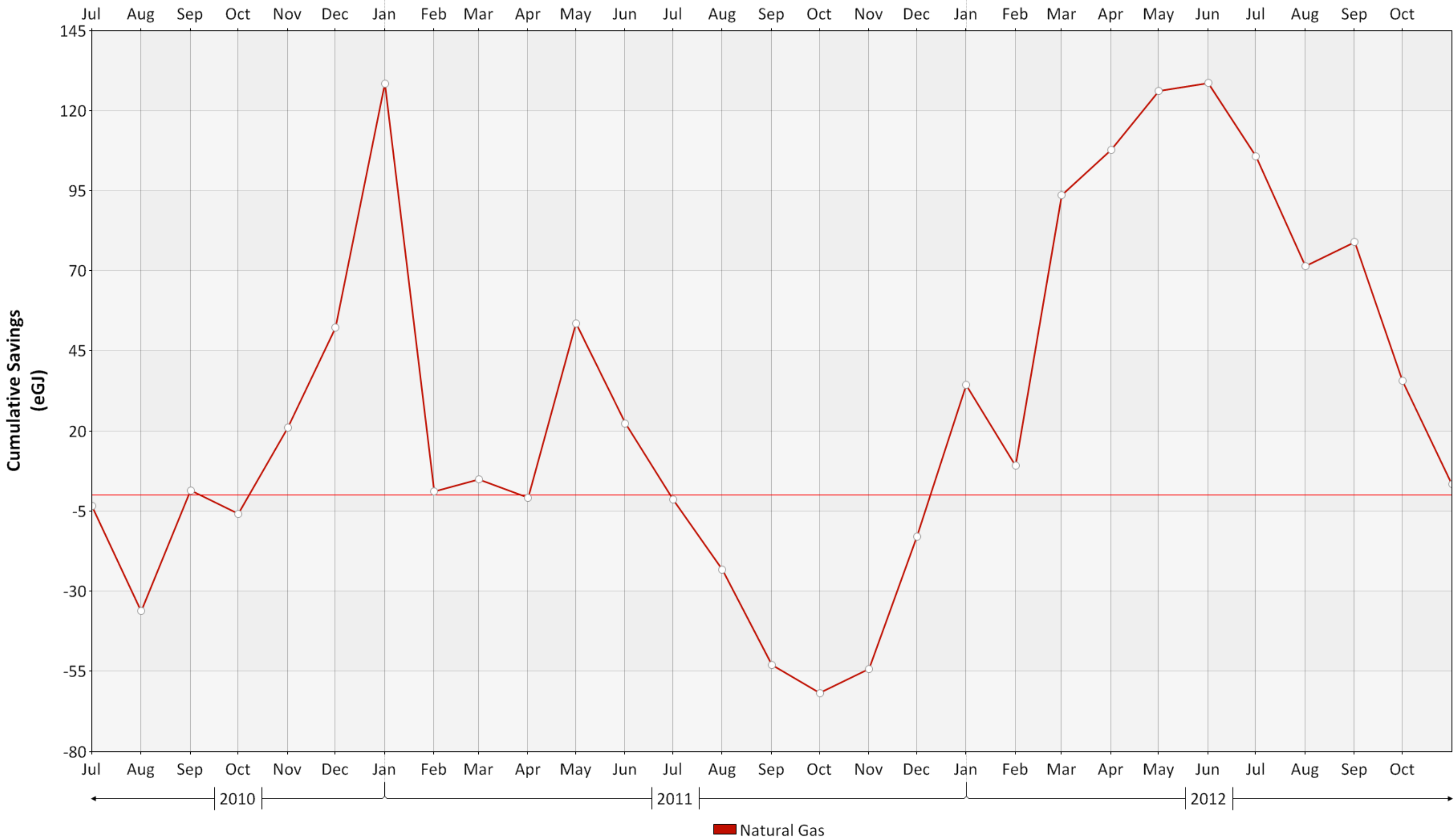
CUSUM: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0008-291374 - 1826 Barclay Street**



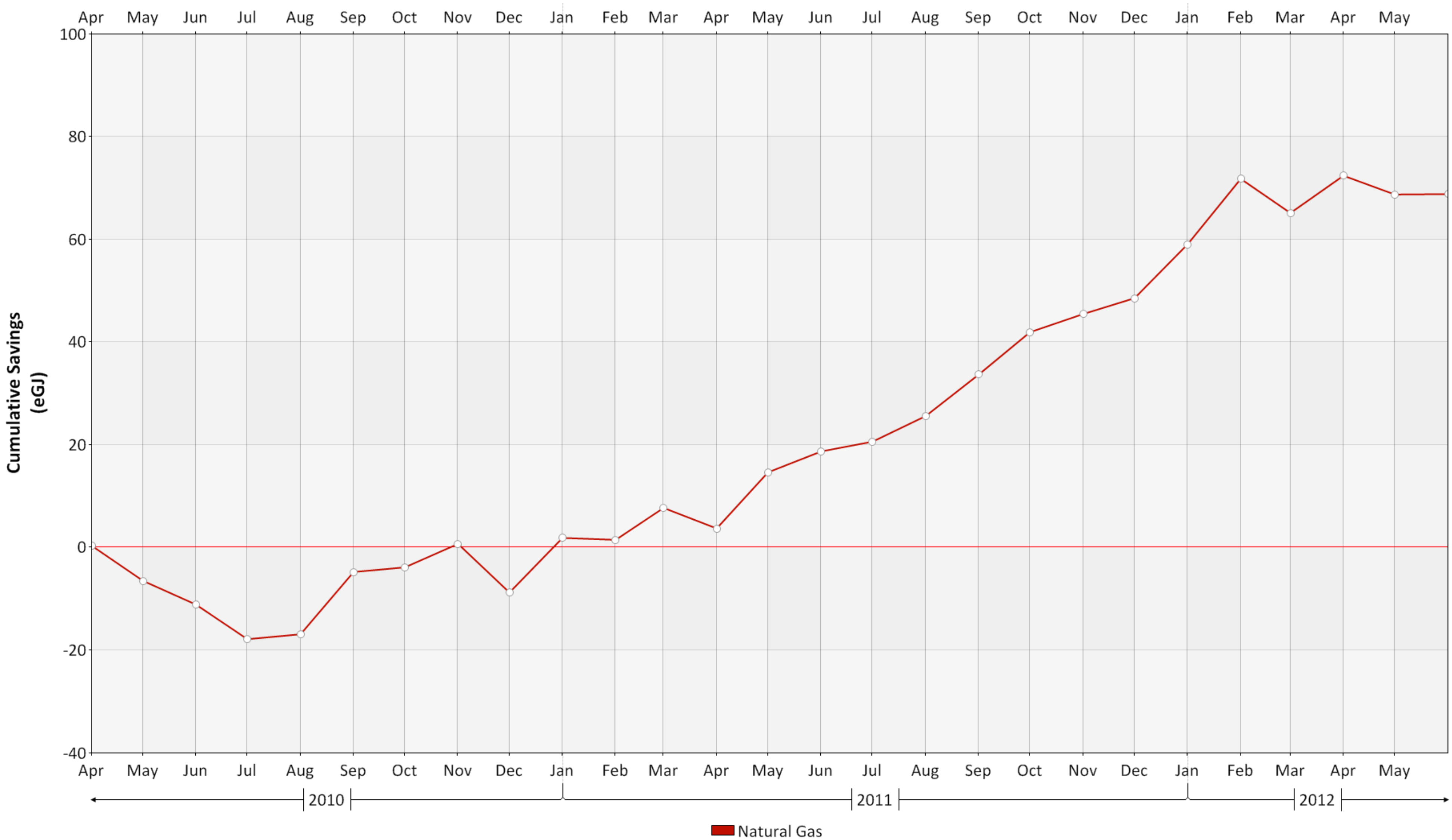
CUSUM: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0009-486157 - 3766 West 7th Avenue**



CUSUM: Site

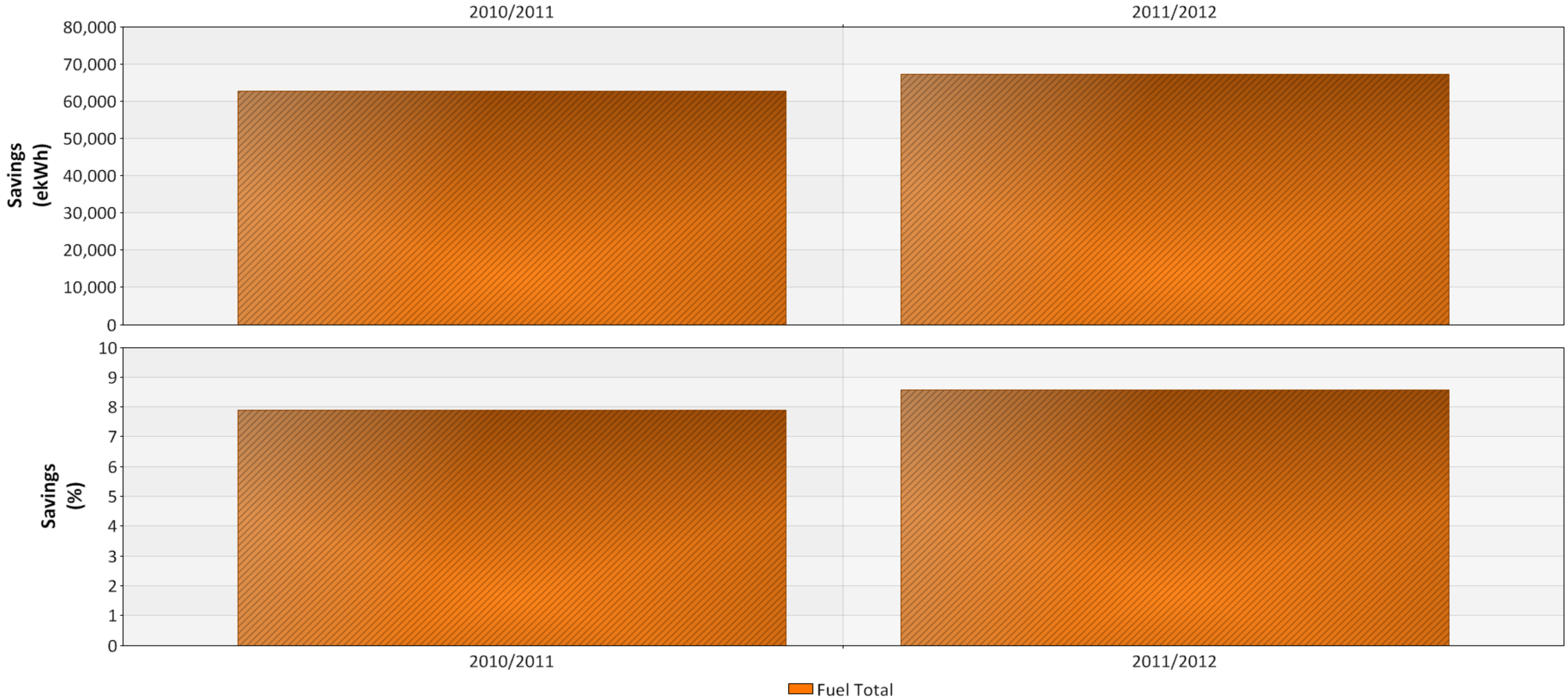
Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0010-721055 - 5440-201 A Street**



APPENDIX H: ANNUAL NATURAL GAS SAVINGS – SITE

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0001-763042 - 32101 Mt. Waddington Avenue**

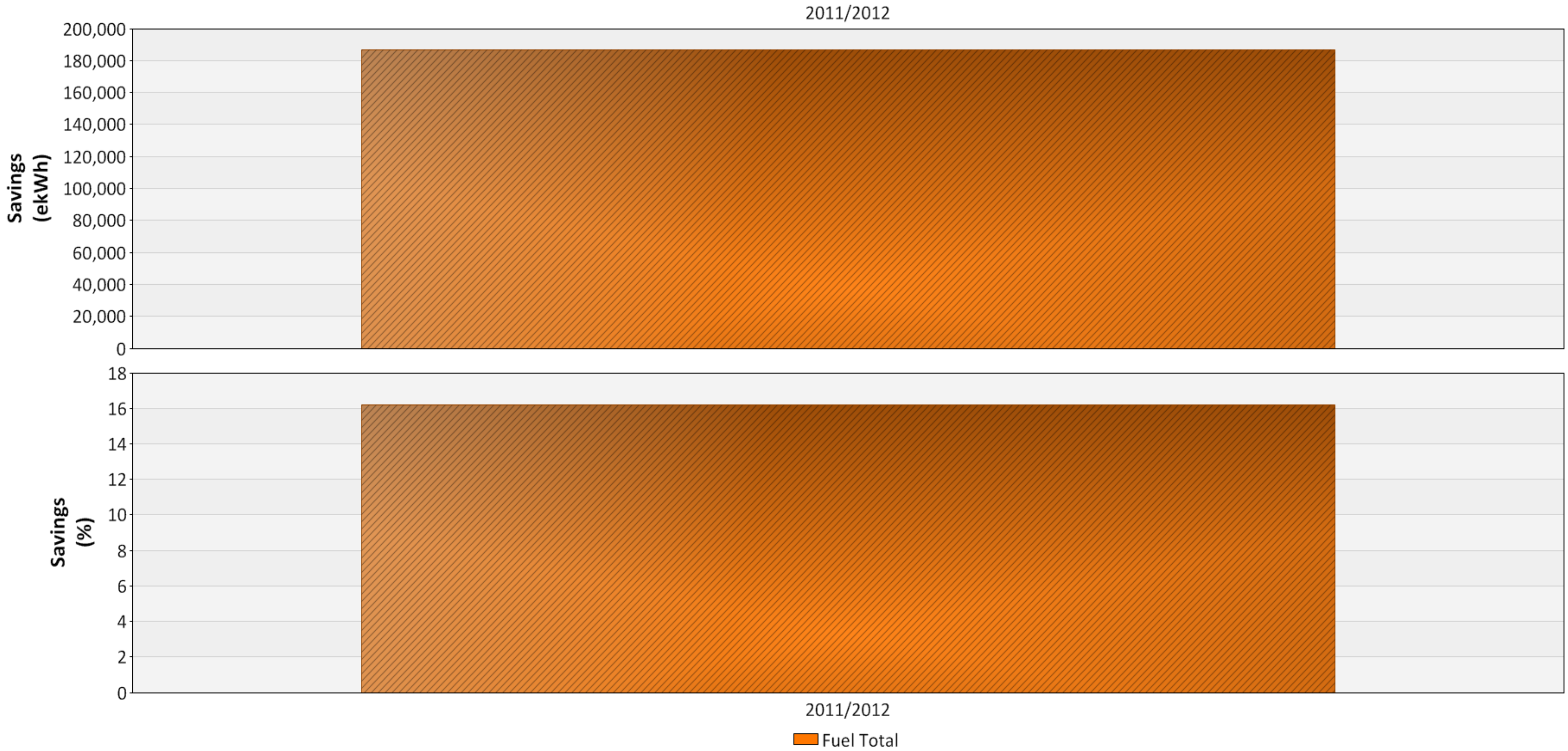


Year[1]	Fuel Total Actual GJ	Fuel Total Prorated Baseline GJ	Fuel Total Savings Abs. GJ	Fuel Total Savings %
2010/2011	2,631	2,857	226	8
2011/2012	2,583	2,826	243	9
Total:	**5,215**	**5,683**	**469**	**8**

[1] "Year" refers to fiscal year ending in April
Brown indicates missing data and Blue indicates prorated data.

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0003-743213 - 2575 Ware Street**

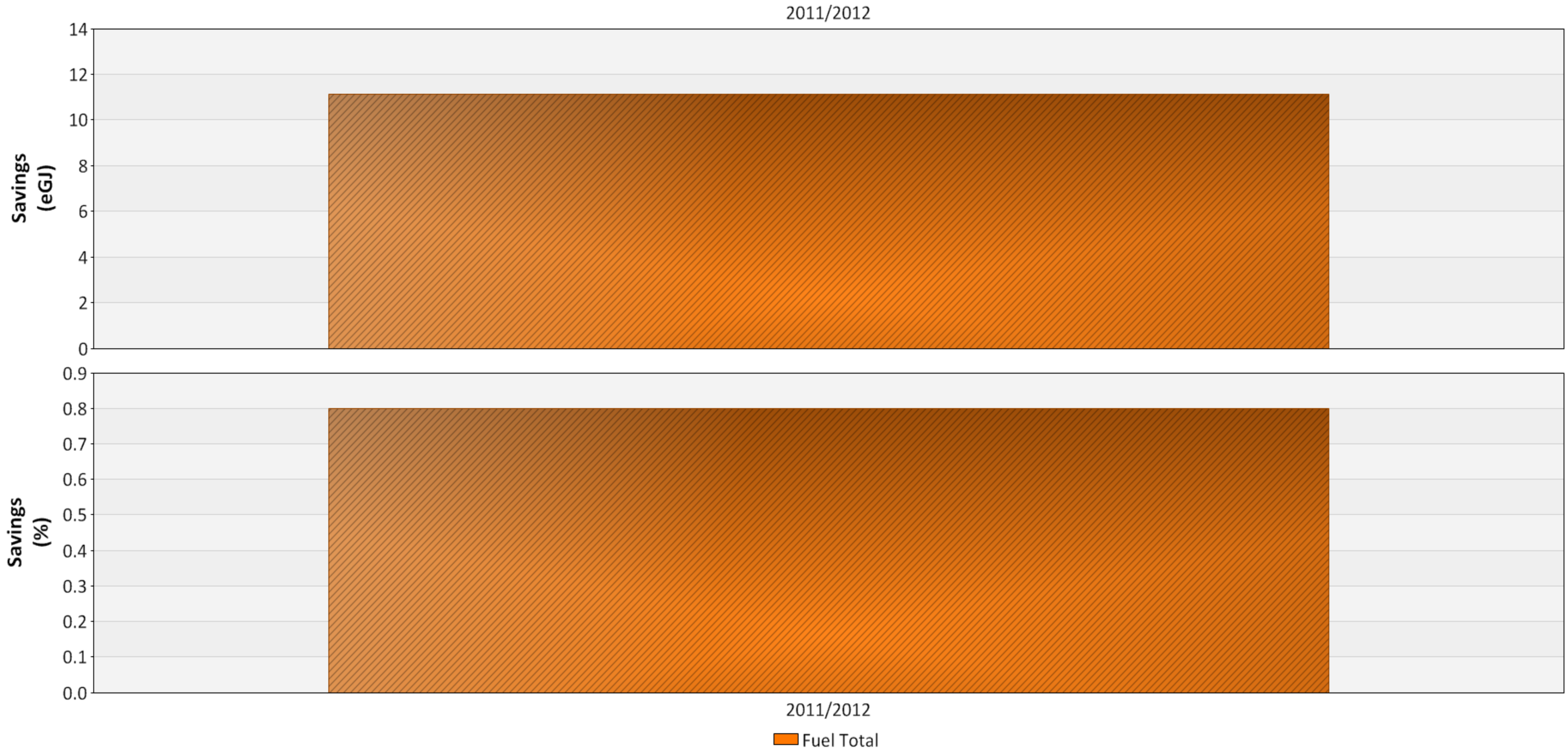


Year[1]	Fuel Total			
	Prorated Actual	Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	3,480	4,153	673	16

[1] "Year" refers to fiscal year ending in August
Brown indicates missing data and Blue indicates prorated data.

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0005-713430 - 18 Jack Mahony Place**

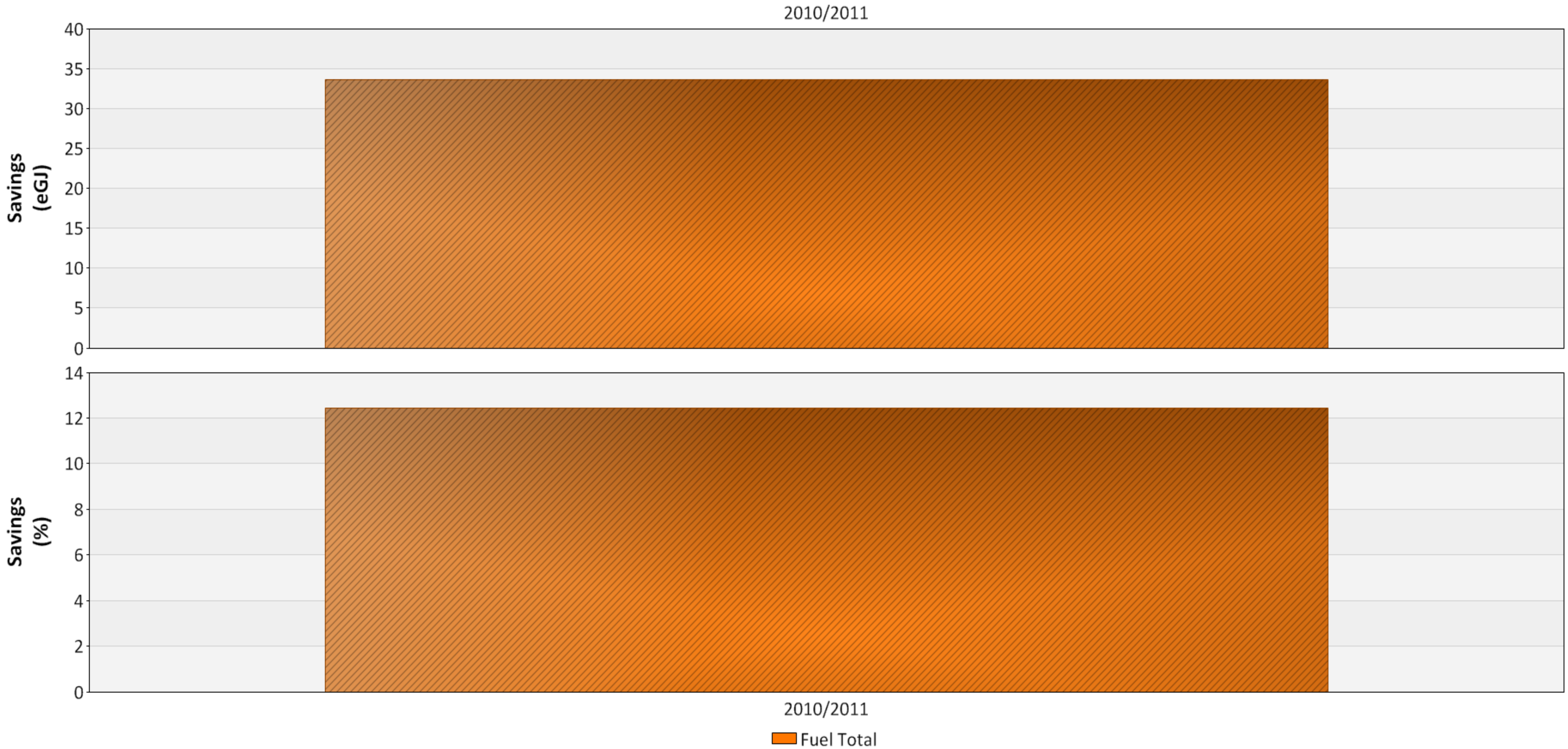


Year[1]	Fuel Total			
	Actual	Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	1,383	1,394	11.2	1

[1] "Year" refers to fiscal year ending in February
Brown indicates missing data and Blue indicates prorated data.

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0006-471682 - 1678 W. 7th Avenue**

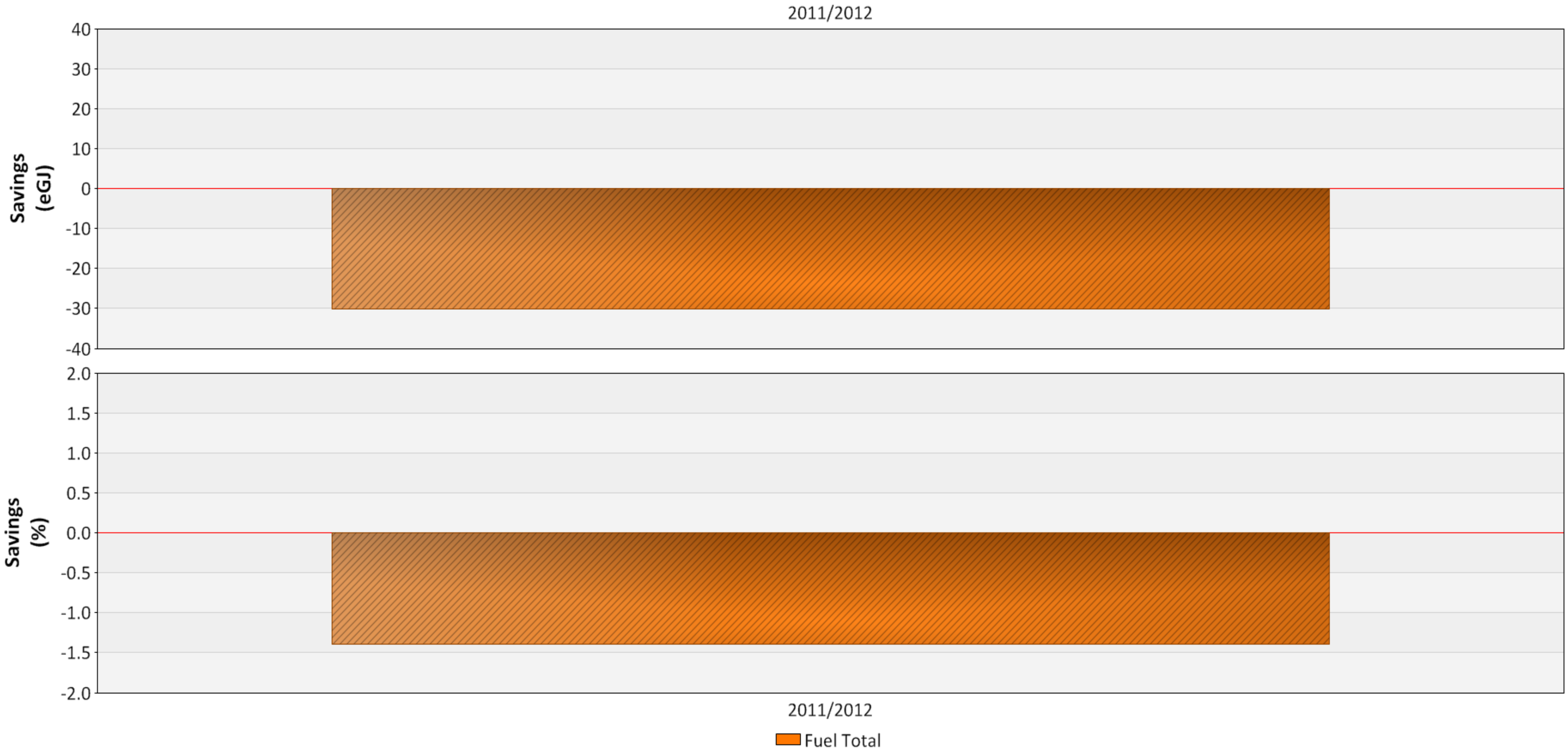


Year[1]	Fuel Total			
	Actual	Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2010/2011	237	270	33.7	12

[1] "Year" refers to fiscal year ending in September
Brown indicates missing data and Blue indicates prorated data.

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTPP0007-59502 - 712 Sahali Terrace**

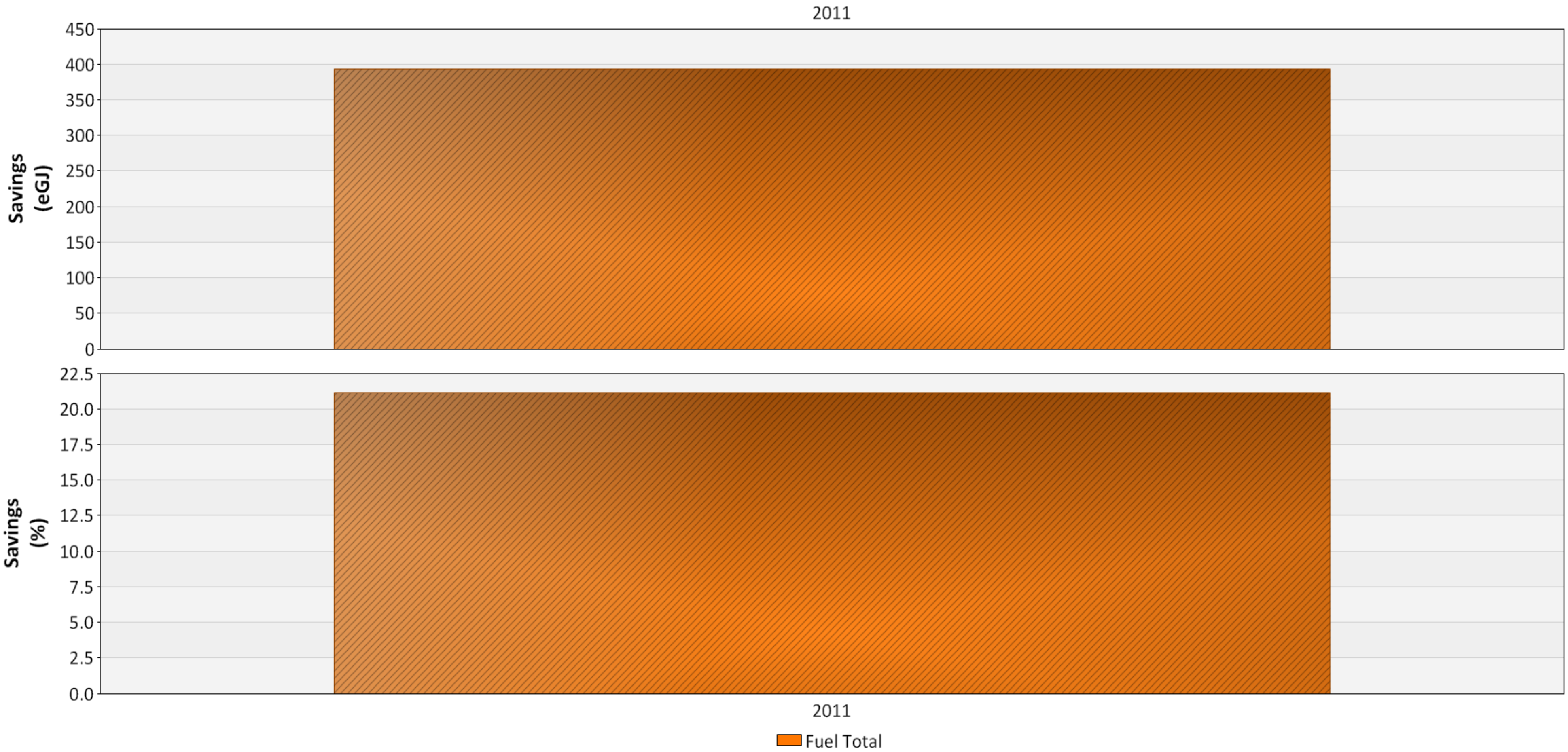


Year[1]	Fuel Total			
	Actual	Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	2,191	2,161	-29.9	-1

[1] "Year" refers to fiscal year ending in June
Brown indicates missing data and Blue indicates prorated data.

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0008-291374 - 1826 Barclay Street**

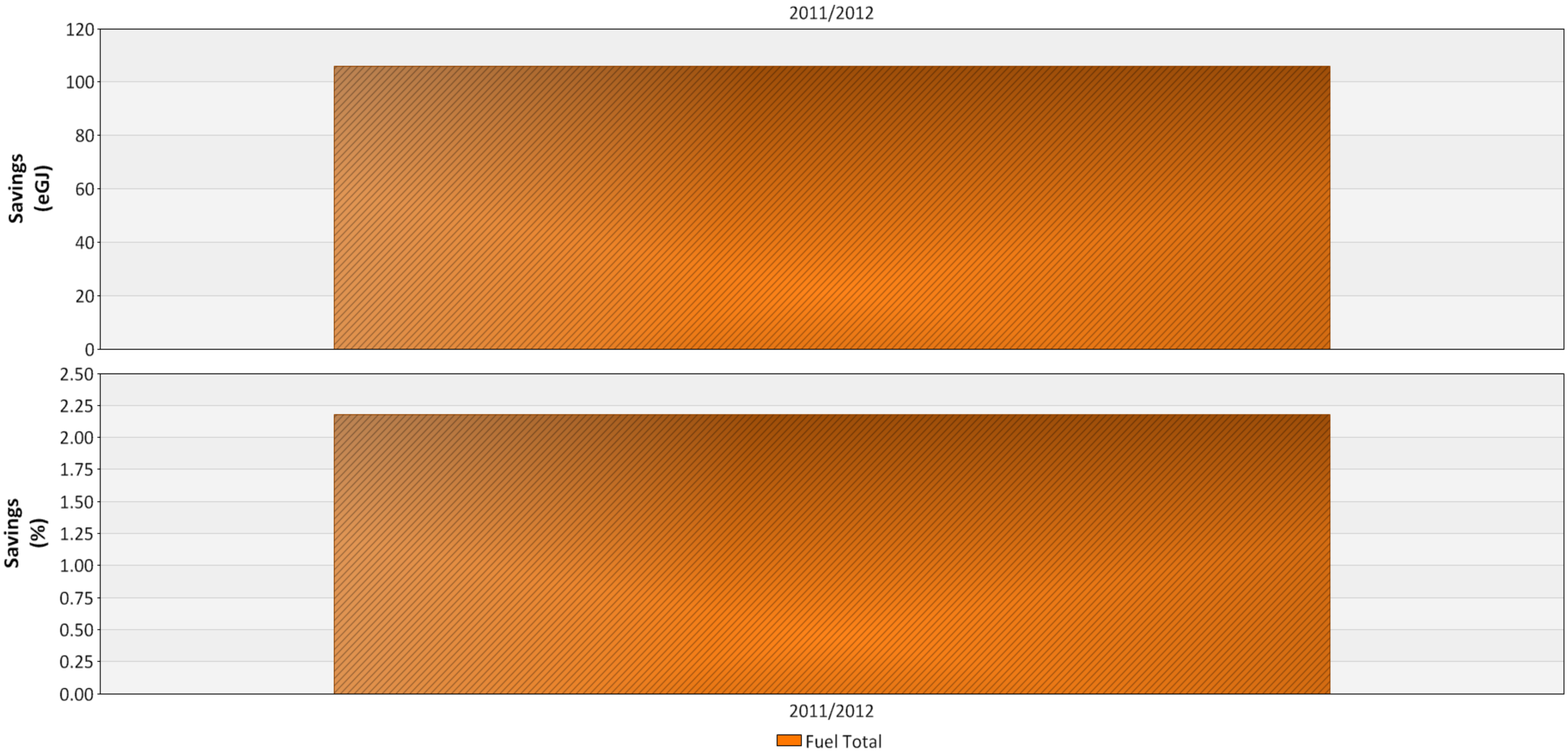


Year	Fuel Total			
	Actual	Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2011	1,468	1,862	394	21

Brown indicates missing data and Blue indicates prorated data.

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0009-486157 - 3766 West 7th Avenue**

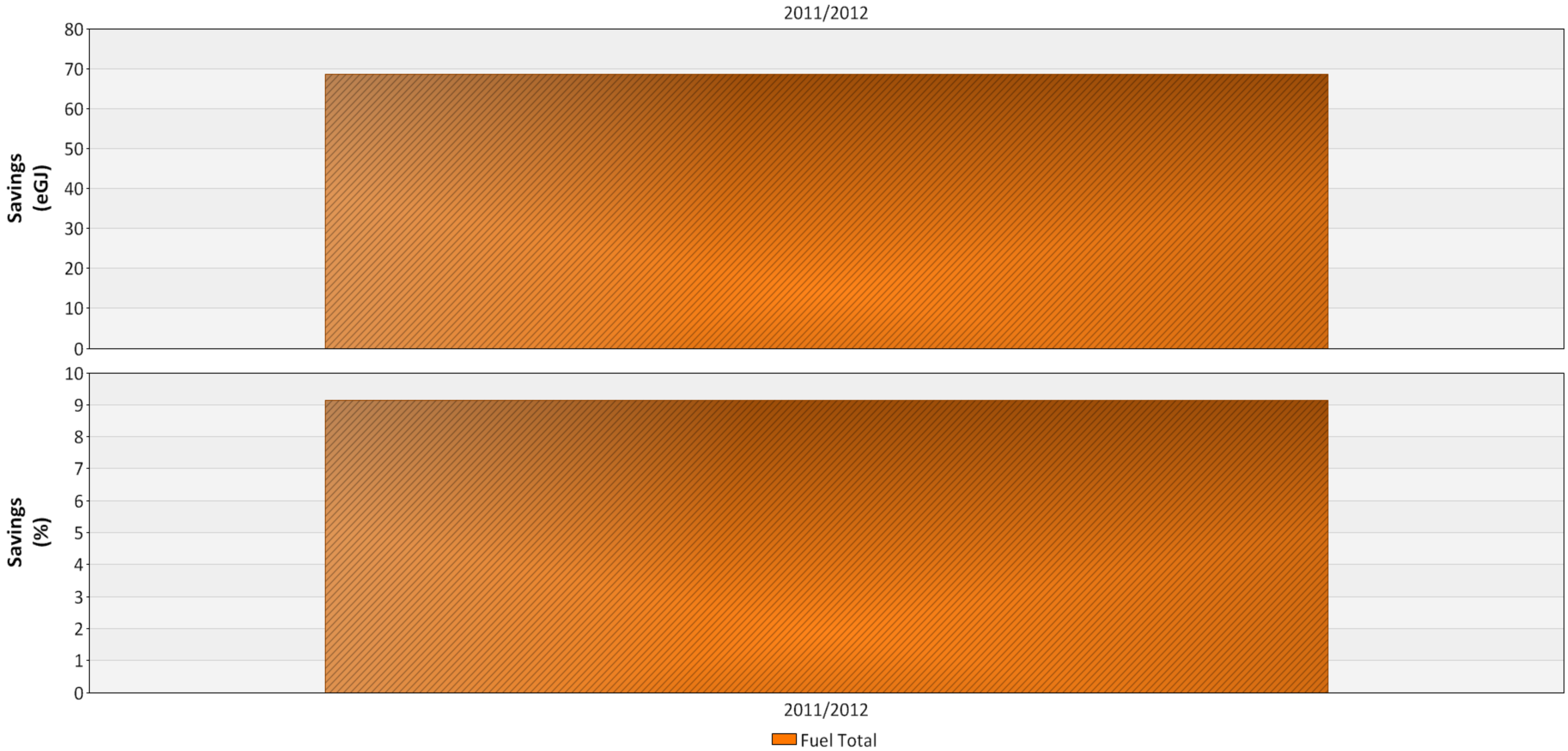


Year[1]	Fuel Total			
	Actual	Baseline	Savings	
			Abs.	%
	GJ	GJ	GJ	
2011/2012	4,756	4,862	106	2

[1] "Year" refers to fiscal year ending in May
Brown indicates missing data and Blue indicates prorated data.

Annual Energy Savings: Site

Project: **FortisBC - Fireplace Timers Pilot (2012259)**
Site: **FTP0010-721055 - 5440-201 A Street**



Year[1]	Fuel Total			
	Actual	Baseline	Savings	
	GJ	GJ	Abs. GJ	%
2011/2012	682	751	68.7	9

[1] "Year" refers to fiscal year ending in March
Brown indicates missing data and Blue indicates prorated data.

Prism ENGINEERING
saving you energy

ENERGY SPECIALIST PROGRAM – ENERGY SAVINGS AUDITOR

FORTIS BC™

Prepared for: Cindy Wong
Prepared by: Jermin Hsieh P.Eng., and Robert Greenwald, P.Eng. Prism Engineering Ltd.
Project No: 2012014
March 31st, 2013 FINAL

Limits of Liability

This report was prepared by Prism Engineering Limited for FortisBC. The material in it reflects our professional judgement in light of the information available to us at the time of preparation. The savings calculations are estimates of savings potential and are not guaranteed. The impact of building changes, building use changes, new equipment, additional computers, and weather needs to be considered when evaluating savings. Without express written permission, any use which a third party makes of this report, or any reliance on or decisions to be made based on it, are the responsibility of such third parties. Prism Engineering Limited accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this report.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES AND GLOSSARY

1. EXECUTIVE SUMMARY

Prism Engineering Ltd. (Prism) and Clear Lead were contracted by Fortis BC to review and verify the natural gas savings from the Energy Specialist program. Fortis BC wanted to determine the savings resulting from projects identified and implemented with the support of Energy Specialists that were not captured in other Fortis BC incentive programs.

The starting point for the evaluation was the "quarterly reports" submitted by Energy Specialists. Prism initially identified sixty-eight (68) completed projects for which project reviews and savings verification were required. After undergoing more scrutiny and a number of filters, twenty-nine (29) projects were evaluated. The remaining projects were not included for one of the following reasons:

- fifteen (15) projects were part of the PSECA program and the savings from these projects cannot be claimed under the Energy Specialist Program;
- twelve (12) projects were not reviewed because the estimated savings were approximately sixty GJ or less. The cost/effort to review the savings were not deemed worthwhile;
- five (5) projects were not reviewed and the analysis postponed due to insufficient project documentation. Prism Engineering plans to evaluate these projects based on a CUSUM analysis once sufficient post retrofit data becomes available;
- three (3) new construction projects had savings calculated based on energy models. Prism Engineering plans to evaluate these projects based on an energy use analysis once sufficient post retrofit data becomes available.
- four (4) projects were not reviewed because the Energy Specialist was not able to provide adequate calculations for review.
- UBC submitted a project (Bio Research Development Facility – BRDF) which was unique, and as such, was not included in the program.

Table 1 provides an overview of the results.

Table 1: Result From Completed Projects in 2011 and 2012

Category	# of projects reviewed	Prism / Clear Lead verified annual savings (GJ/year)	NPV of GJ Savings (*)
2012 Completed Projects	12	1,081	4,713
2011 Completed Projects	17	8,742	24,943
Total	**29**	**9,823**	**29,656**

(*) Calculation of NPV of GJ Savings was performed as per FortisBC methodology

In addition to the annual savings and the NPV of savings, Fortis BC also has a methodology for calculating the Present Value (PV) for the natural gas cost savings. Based on a discount rate of 7.79% and a marginal rate for natural gas of $7.91 GJ (including) $1.50 /GJ for carbon tax, Table 2 shows the PV for projects completed based on the expected life for each measure category.

Table 2: Present Value Natural Gas Cost Savings: 2011 and 2012 Projects

Projects completed in	2011	2012
Present Value Natural Gas Cost Savings over Measure Life	$216,681.9	$37,304.1

2. BACKGROUND AND METHODOLOGY

2.1 Background

The Energy Specialist Program was launched in May 2010. Only organizations which currently have a BC Hydro funded Energy Manager position were eligible for funding of an Energy Specialist. At the time of this analysis (November 2012), 17 Energy Specialist were employed and actively promoting natural gas energy efficiency and conservation projects. Prism Engineering was informed that this program will expand to up to 35 Energy Specialists by the end of 2012.

The sole purpose of Prism Engineering's evaluation project is to verify the energy savings from projects which are not attributed to current FortisBC incentive programs. The energy efficiency projects with the associated energy savings are self-reported by the Energy Specialists and Prism Engineering was contracted to:

- identify the projects which should be verified based on the criteria described in section 2.2;
- collect project documentation which includes the savings calculation and supporting documentation;
- conduct follow up phone calls and site visits if needed;
- Verify and report on energy savings by GJ and NPV.

As outlined in the scope of work, FortisBC expected that at least 80% of the total natural gas savings reported by Energy Specialists to be audited and verified. Prism Engineering took the approach that all projects which were selected according to the criteria as listed in section 2.2 were targeted to be verified except projects

- with minor annual savings (smaller than 60 GJ / year); and
- which received PSECA funding as savings were already claimed under the PSECA program;

Detailed breakdowns of the individual projects falling in each of the categories are provided in section 3.

2.2 Methodology to Identify Projects for Savings Verification

All quarterly reports were reviewed for completeness and Prism Engineering contacted all Energy Specialists to

- fill in the gaps; and
- for clarification of contradicting information.

After the quarterly reports were "cleaned up", we consolidated all quarterly reports and applied the following filters to determine the projects which were subject to evaluation:

- PCP or PIP (project completed or project in progress);
- no incentive program and savings claimed; and
- project completed in 2011 and 2012.

Based on this analysis, 68 projects were identified for review from 11 organizations.

Prism Engineering identified seven projects with Northern Health Authority (NHA) for which Prism Engineering was involved in the initial savings analysis. These projects were submitted to the ClearLead Consulting Inc., the secondary vendor, for savings verification. ClearLead Consulting Inc.'s report is presented in Appendix B.

2.3 Methodology for Gathering of Project Documentation

Prism Engineering followed following the steps for the data gathering process:

- Prism Engineering developed generic project questionnaires for different types of projects. These forms are provided in Appendix D. The project questionnaires also included a list of documents where the Energy Specialists had to submit for our review;
- the Energy Specialists were provided with a separate questionnaire for each of their projects;
- upon receipt of the filled out questionnaire, savings calculation and supporting documentation, Prism started our project review. The completed questionnaires will be provide to FortisBC along with the final report and reviewed measure calculation;
- Energy Specialists were contacted by phone if required to discuss details of their projects. Prism Engineering conducted one site visit at UBC to discuss the BRDF project.

2.4 Methodology for Savings Evaluation

We identified two different approaches in verifying savings and determined which method to apply on a project by project basis. In the interest of the project budget we applied the most cost effective method. The flow chart below illustrates the different approaches.

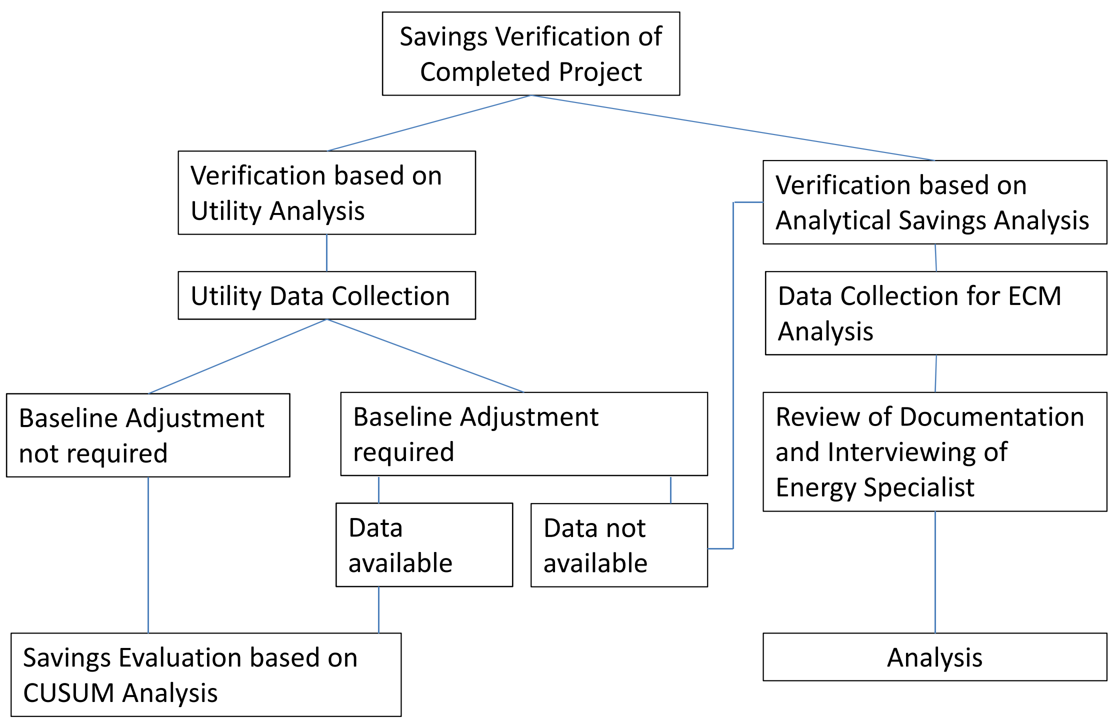


Figure 1: Flow Chart Methodology for Savings Verification

For some of the projects, a CUSUM analysis was performed without the data collection process as CUSUM charts were available in the report provided by the Energy Specialist, such as for BC Hydro COp projects.

2.5 Documentation of Savings Verification

A summary of the savings verification results is provided in the subsequent sections of this report and in a summary Excel spreadsheet. This spreadsheet will be provided to FortisBC along with the raw datasets (project documentation and project savings calculation) as per deliverables.

3. RESULTS OF SAVINGS VERIFICATION

3.1 Projects Completed in 2012

Prism Engineering performed the savings verification of 12 projects completed in 2012 with the results as shown in Table 3.

Table 3: Savings Verification for Projects Completed in 2012

ECM Code	Organization	Project Name	Project Category	Measure Life from ES	ES claimed annual savings (GJ/year)	Prism verified annual savings (GJ/year)	% of claimed savings	2012 prorated savings (GJ)
BCIT_2012_ECM3	BCIT	Potwasher Replacement #2	Dishwasher Replacement	20	155	155	100%	129
IHA_2012_ECM1	IHA	Cottonwoods Domestic Hot Water	Instantaneous Water Heater	15	75	71	95%	53
SFU_2012_ECM1	SFU	TASC 1 Weather Predictor	Controls	5	100	11	11%	0
SFU_2012_ECM2	SFU	Shrum Science Faucet Aerator	Replacement of Flow Fixture	15	175	160	91%	141
SFU_2012_ECM3	SFU	South Science Building Faucet Aerator	Replacement of Flow Fixture	15	60	55	92%	48
SFU_2012_ECM4	SFU	West Mall Complex Demand Controlled Ventilation	Controls	5	420	135	32%	24
SFU_2012_ECM5	SFU	Maggie Benston Centre Weather Predictor	Controls	5	100	35	35%	35
SFU_2012_ECM6	SFU	Install a Timer for the Hot Water Pump in the Diamond Alumni Centre	Controls	10	102	0	0%	0
SFU_2012_ECM7	SFU	Maggie Benston Building Demand Control Ventilation	Controls	20	500	199	40%	76
SFU_2012_ECM9	SFU	Robert C Brown Hall Faucet Aerators	Replacement of Flow Fixture	15	120	103	86%	67
SFU_2012_ECM11	SFU	Energy Efficient Nozzle for Mackenzie Café	Replacement of Flow Fixture	5	72	60	83%	19
SFU_2012_ECM12	SFU	Energy Efficient Nozzle for Dining Hall	Replacement of Flow Fixture	5	108	97	90%	31
				Total	**1,987**	**1,081**	**54%**	**625**

The total claimed savings of all 12 projects were almost 2,000 GJ per year whereas Prism verified that only 54% of the claimed savings were reasonable.

We identified the largest difference between claimed energy savings and verified energy savings were for controls measures such as Demand Controlled Ventilation and Weather Predictor measures. The claimed savings were provided by the Energy Specialists based on calculation from consultants and Prism Engineering's calculation showed that the savings were overestimated.

All 2012 projects were prorated based on their reported project completion date and the verified annual savings. We estimated that 625 GJ of natural gas savings were realized in 2012 through the projects completed in 2012.

3.2 Projects Completed in 2011

Prism Engineering and ClearLead Consulting Inc. performed the savings verification of 17 projects completed in 2011 with the results shown in Table 4. ClearLead Consulting Inc. performed the savings verification for seven Northern Health Authority projects with the detailed results as provided in Appendix A.

Table 4: Savings Verification for Projects Completed in 2011

ECM Code	Organization	Project Name	Project Category	Measure Life from ES	ES claimed annual savings (GJ/year)	Prism / Clear Lead verified annual savings (GJ/year)	% of claimed savings	2011 prorated savings (GJ)
BCIT_2011_ECM1	BCIT	Automotive Virtual Paint Tool	Other	10	55	15	27%	15
BCIT_2011_ECM2	BCIT	Sustainability Precinct Special Project: NE-04 DDC Control Recommissioning (Heat Doctor Pilot)	Control	5	270	706	261%	0
Nvan_2011_ECM4	District of N. Van	Parkgate CC Solar Hot Water	SHW	30	75	75	100%	0
NHA_2011_ECM1	NHA	GR Baker - MUA1 Heat Recovery Control	Control	10	196	196	100%	82
NHA_2011_ECM2	NHA	GR Baker - MUA1 Hot Deck Supply Air Temperature Control Tune-Up	Control	10	24	24	100%	10
NHA_2011_ECM3	NHA	UHNBC -AHU 804 passing valve	Maintenance	10	140	140	100%	59
NHA_2011_ECM4	NHA	UHNBC -Multizone optimization	Control	10	670	670	100%	281
NHA_2011_ECM5	NHA	UHNBC -Optimize heat recovery controls on MZ2, SF402	Control	10	1,600	1,600	100%	672
NHA_2011_ECM6	NHA	UHNBC -SF314 zone isolation – fourth floor	Other	10	1,200	1,070	89%	449
NHA_2011_ECM7	NHA	UHNBC -Install new heat recovery coil on AHU 405	HR	10	670	670	100%	281
SFU_2011_ECM1	SFU	DHW Tank Isolation in AQ MR1027	Other	5	114	5	4%	2
SFU_2011_ECM4	SFU	Library DHW Tank Setpoint Reduction	Control	5	160	11	7%	4
SFU_2011_ECM5	SFU	Library Faucet Aerator	Replacement of Flow Fixture	15	255	233	91%	16
SFU_2011_ECM6	SFU	ASB Faucet Aerator	Replacement of Flow Fixture	15	120	80	67%	13
SFU_2011_ECM9	SFU	West Mall Complex DHW Setback and Tank Isolation	Control	10	70	36	51%	8
UBC_2011_ECM3	UBC	C.Op. Pilot - N. Scarfe	Control	5	1,670	2,635	158%	2,250
VIHASouth_2011_ECM3	VIHA South	Pre-Rinse Spray Valves, eight sites	Replacement of Flow Fixture	10	576	576	100%	242
				Total	7,866	8,742	111%	4,383

The total claimed savings of all 17 projects amount to 7,866 GJ / year. Prism Engineering and ClearLead Consulting Inc. verified that these 17 projects have a savings potential of 8,742 GJ/year or 11% higher than the claimed savings.

We identified the largest difference between claimed energy savings and verified energy savings were for the controls re-commissioning project at BCIT and one of the COp projects at UBC. The actual savings for both projects was verified based on CUSUM analysis. The savings here were underestimated and the actual savings based on CUSUM analysis proved the higher savings.

All 2011 projects were prorated based on their reported project completion date and the verified annual savings. We anticipate that 4,386 GJ of natural gas savings were realized in 2011 through the projects completed in 2011.

3.3 Projects with Minor Savings

Prism Engineering identified twelve projects with minor savings. The total savings of all of these twelve projects is less than 1% of the total claimed savings of the 68 projects. As the level of effort for the engineering review for these projects are significant and the impact on the overall savings is negligible, we did not perform a savings analysis for these projects.

Table 5: Projects Completed in 2011 and 2012 with Minor Savings

ECM Code	Organization	Project Name	Project Category	Measure Life per ES	ES claimed annual savings (GJ/year)
Nvan_2012_ECM7	District of N. Van	DNV Hall - Replace Water Heater Tank	Other	15	15
Nvan_2011_ECM1	District of N. Van	FH3 Solar Hot Water	SHW	30	20
Nvan_2011_ECM2	District of N. Van	FH4 Solar Hot Water	SHW	30	27
Nvan_2011_ECM3	District of N. Van	FH5 Solar Hot Water	SHW	30	26
SFU_2011_ECM2	SFU	Hamilton Hall DHW Tank Setpoint Reduction	Control	5	17
SFU_2011_ECM3	SFU	Pipe Insulation in AQ MR 1027	Piping Insulation	10	51
SFU_2011_ECM3	SFU	Pipe Insulation in AQ MR 1027	Piping Insulation	10	51
SFU_2011_ECM7	SFU	Interlock Garage Door 7 to the heater	Other	5	4
SFU_2011_ECM8	SFU	Maggie Benston Building Domestic Hot Water Setback	Control	10	50
SFU_2012_ECM8	SFU	Turn Off the Fireplace Pilot Light in the Diamond Alumni Centre	Control	5	8
SFU_2012_ECM10	SFU	Education Building Faucet Aerators	Replacement of Flow Fixture	15	61
VCH_2012_ECM2	VCH Alan Lin	Eye Care Centre - Theatre	Control	15	25
				Total	**354**

3.4 Project Verification Postponed

Prism Engineering collected and reviewed the available project documentation for eight projects where the savings verification could not be performed for the following reasons:

- insufficient project documentation; or
- new construction projects that used energy modelling for savings estimation.

We recommend proceeding with the savings verification of the projects as listed in Table 6 once sufficient post retrofit consumption history is available for a CUSUM analysis.

Table 6: Project Verification Postponed

ECM Code	Organization	Project Name	Project Category	ES claimed annual savings (GJ/year)
BCHousing_2012_ECM1	BC Housing	Group Home energy retrofits	Other	2,110
Nvan_2012_ECM6	District of N. Van	FH3 Retrofit, Renovation + Addition	Renovation	250
SFU_2011_ECM10	SFU	TASC1 CO2 Sensor Adjustment	Controls	500
UBC_2011_ECM1	UBC	Bioscience Renew	Renovation	590
UBC_2011_ECM2	UBC	C.Op. Pilot - Buchanan	Controls	826
UBC_2012_ECM4	UBC	ESSB	New Construction	468
UBC_2012_ECM5	UBC	Pharmacy Building	New Construction	4,624
VCH_2012_ECM8	VCH Alan Lin	VGH - Willow Pavilion	New Construction	2,510
				11,878

3.5 Projects Without Savings Calculation

The four projects as listed in Table 8 were provided by the Energy Specialists without savings calculations. Prism Engineering contacted the Energy Specialists to discuss the individual projects and we were provided the following information:

- BCIT: no further information available
- Coil Cleaning: gas savings was an estimate. Prism Engineering's view on savings associated with coil cleaning is that this measure provides savings on fan electricity due to reduced static pressure but no or little quantifiable gas savings.
- Gas savings from piping insulation was estimated by a former Energy Manager who left the organization and did not file project documentation.
- Prince George Cancer Agency is a new construction project and the gas savings were estimated without any supporting calculations.

Table 7: Projects without Savings Calculations

ECM Code	Organization	Project Name	Project Category	Measure Life by ES	ES claimed annual savings (GJ/year)
BCIT_2012_ECM4	BCIT	Demolition of NW07 Building	Other	N/A	500
PHSA_2011_ECM2	PHSA	Coils cleaning at RGH	Other	5	1,250
PHSA_2011_ECM3	PHSA	Repair insulation to Hot Water Pipes at GPC	Piping Insulation	10	1,600
PHSA_2011_ECM4	PHSA	Prince George Cancer Agency	New Construction	15	5,300
				Total	**8,650**

3.6 Bio Research Development Facility (BRDF)

Lillian Zaremba, Energy Specialist at UBC, reported the Bio Research Development Facility as one of the UBC projects. An in-person interview was carried out at UBC to discuss the project and gather detailed project documentation.

The 2012 natural gas savings for the BRDF was calculated using following data:

- metered steam output of the BRDF with meter readings taken on a daily basis;
- daily central plant heating efficiency which is determined on a daily basis using the daily central plant steam output and daily natural gas input; and
- sub-metered gas consumption of the BRDF plant (process load).

Operation of the BRDF commenced in September 2012 and the data, as described above, was provided by Lillian Zaremba for the savings verification. Prism Engineering verified that the operation of the BRDF displaced 19,240 GJ of natural gas in 2012 at UBC.

The verified savings is about 46% of the expected natural gas savings which is due to lower run hours during the plant commissioning process.

4. FINANCIAL ANALYSIS

The Present Value represents the current worth of a future sum of money or stream of cash flows (annual gas cost savings) given a specified discount rate over the measure life. The Present Value for the projects completed in 2011 and 2012, shown in Table 8, were calculated using following assumption:

- discount rate of 7.79% as provided by FortisBC;
- total marginal rate for natural gas of $7.914 which is the average of the Rate 3 costs (LM, Inland and Columbia) according to January 2013 rate schedule plus $1.50 for carbon tax;
- measure life as provided by FortisBC or estimated by Prism; and
- verified annual natural gas savings.

Table 8: Present Value Natural Gas Cost Savings 2011 and 2012 Projects

Projects completed in	2011	2012
Present Value Natural Gas Cost Savings over Measure Life	$216,681.9	$37,304.1

Free-ridership was considered where available in the Present Value calculation. FortisBC provided Free-rider rates for some of the project categories which were taken into consideration using following methodology:

- NTG Ration = (100 % - Free rider rate)
- Gas Savings adj for Free Rider (GJ/year)= Annual verified gas savings (GJ/year) x NTG
- Gas Savings adj for Free Rider (GJ/year) is then used for NPV calculation.

FortisBC suggested a NPV of GJ savings which takes into account the annual gas savings (GJ/year), discount rate, free rider rate and measure life. Prism Engineering was provided with the calculation methodology but not with the background of this approach. As such, the results are included in Appendix B for reference only. Please note that the values provided are gas savings in GJ and not cost savings.

5. RECOMMENDATIONS

Prism Engineering gained comprehensive knowledge of the quality of the quarterly reports and project savings analysis submitted by the individual Energy Specialists. We experienced both extremes for the project documentation and energy savings analysis: some projects were well documented with high quality savings analysis whereas some projects were submitted with limited or no documentation claiming substantial energy savings.

As such Prism Engineering identified the following opportunities for improvements of the Energy Specialist program:

5.1 Ongoing Review of Quarterly Reports and Savings Verification

We recommend that Energy Specialists should be required to submit project documentation and savings calculations on a quarterly basis as part of their submission. An ongoing review of the quarterly reports by Fortis BC and/or its consultants should be carried out on a regular basis. Upon completion of the review, Energy Specialists should be provided with feedback on their submissions so that they can provide complete and accurate savings estimates.

The proposed approach will reduce the Energy Specialist's efforts and FortisBC's expenditures in the program verification as the Energy Specialists would

- provide documentation shortly after the completion of the project when documentation is still readily available; and
- have strong motivation to provide complete project documentation resulting in reduced efforts during the verification process.

FortisBC would also benefit from a review on quarterly basis as the success of the Energy Specialist Program can be assessed throughout the year. This might become more important in the next years as the program grows to 35 Energy Specialists. The savings verification on an annual basis might become increasingly challenging due to the increased numbers of projects and the time constraints for the savings verification.

5.2 Engineering Support for Energy Specialist

During our savings verification process, Prism Engineering identified that some of the Energy Specialists would have benefitted from engineering support which would provide the following positive effects:

- more guidance for the Energy Specialist during the project documentation and savings estimate process;
- decreases the numbers of projects for which little or no documentation was provided; and
- decreases the likelihood of overestimating energy savings.

We envision that the Engineering support would include engineering advice and guidance on developing energy savings calculation methodology. The actual energy savings calculations should then be performed by the Energy Specialists or their consultants.

5.3 Kick off Event and Energy Specialist Challenge

As the Energy Specialist Program expands, we recommend hosting Kick Off Events to provide new Energy Specialists with training on expectations of project documentation and savings analysis.

Prism Engineering could offer their services during Kick Off Events to discuss the documentation requirements and present examples of good and bad project documentation. This will provide new Energy Specialists with guidance from the onset and reduce efforts for the Energy Specialists as they will be more likely to compile useful project documentation in their day to day operation. As such, efforts and expenditures will be reduced during the project evaluation.

Prism Engineering identified a wide spread in the number of submitted projects and associated energy savings potential of implemented projects. We recommend establishing competitions and challenges to encourage and recognize Energy Specialists. Prism Engineering has been involved in numerous social marketing initiatives which involved competitions of different sites within the same organization and experienced great success in creating positive competition.

5.4 Training

We have identified that some of the Energy Specialists would greatly benefit from training on energy efficiency software which will assist them with quantifying projects. This will reduce the efforts for the Energy Specialists in developing their own calculations and free up time for them to identify other opportunities. Furthermore, this would also provide the opportunity for more accurate savings analysis and reduced efforts during the verification process.

Prism Engineering recommends training on RETScreen and RETScreen Plus for the following reasons:

- Software available at no cost;
- easy to learn and easy to use; and
- can be used for a wide range of commercial applications.

For RETScreen we recommend training on the Energy Efficiency Module and Solar Hot Water Module. RETScreen Plus would allow Energy Specialist to perform CUSUM analysis for projects for M&V purposes.

Prism Engineering has provided RETScreen and RETScreen Plus trainings for Energy Managers and for the BCIT’s Sustainable Energy Management Advanced Certificate (SEMAC) Program with great success and could provide such training to FortisBC’s Energy Specialists.

5.5 Energy Specialist Project Database

Although Energy Specialists are using similar templates for quarterly reporting, many have modified the format and content to suit their requirements. It is difficult to combine the spreadsheets into a “master” version suitable for program evaluation. Consideration should be given to ensuring a uniform reporting spreadsheet and/or require projects be entered into a database created for the program with the required fields and information.

5.6 ClearLead Consulting Inc.s Input for Next Steps and Lesson Learned

Through a variety of work including the FortisBC Energy Assessment Program, ClearLead has had the pleasure of working with most of the Energy Specialists, and we have made some observations about the program. Many Specialists have charged forth and made a great start.

The commercial custom design program is eagerly awaited, as many Specialists identify very significant opportunities outside of the existing incentive programs, and would appreciate assistance in selling these internally.

The Specialists are often under the direction of a BC Hydro sponsored Energy Manager. This has a natural synergy with benefits including mentorship, a larger "team" size, and sharing of network relationships. However, the Specialists may find themselves fitted into a pre-established program in their organization where goals are measured more often in kWh rather than GJ. They also may be assigned tasks of an administrative nature such as reporting, completing documentation, monitoring consumption, and funding research.

Many of the Specialists do not have the technical background to specify or evaluate measures themselves, and have not yet developed the spending discretion within their organization to hire outside help. We have had many opportunities to provide ad hoc technical input and resource directions. The backgrounds and skill sets of the Specialists vary, and some may need time to adjust to the culture of the organization they have joined. At this stage, it may be difficult to accurately evaluate an individual's impact in an organization. It is possible that the effect of "soft skills" and relationship building of some Specialists will have a significant impact on the course of investment and operations to reduce natural gas consumption in the future. The savings from this may be very difficult to quantify, but should be documented nonetheless. The Specialists are always are highly appreciative of opportunities for networking, sharing of specific examples, success stories, resources and technical training.

This section of the report was prepared by Adrian Partridge President, ClearLead Consulting Ltd., North Vancouver, BC, P:604.229.6159, C:604.209.8938, adrian@clearlead.ca, www.clearlead.ca

APPENDIX A: CONTACT INFORMATION

CLIENT CONTACT	**FortisBC**
Address	16705 Fraser Highway, Surrey V4NOE8
Contact Name	Cindy Wong, B.A. Econ
Title	Evaluation, Measurement & Verification Specialist
Telephone	(778) 578-3853
Fax	(604) 592 - 7661
Email	Cindy.Wong@fortisbc.com

CONSULTANT CONTACT	**PRISM ENGINEERING LTD.**
Address	320 – 3605 Gilmore Way, Burnaby, BC V5C 2J1
Telephone	(604) 298-4858
Fax	(604) 298-8143
Website	www.prismengineering.com
Contact Name	Robert Greenwald, P.Eng
Title	President
Direct Line	(604) 205-5500
Email	Robert@prismengineering.com
Contact Name	Ken Holdren, P.Eng.
Title	Associate
Direct Line	(604) 205-5508
Email	Ken@ prismengineering.com
Contact Name	Jermin Hsieh, P.Eng.
Title	Energy Engineer
Direct Line	(604) 298-4858
Email	Jermin@ prismengineering.com

APPENDIX B: CLEARLEAD CONSULTING INC. SAVINGS VERIFICATION

Fortis BC Energy Specialist Review of Energy Saving Estimates
Evaluated by ClearLead (Prim Conflict)

Building Name	Measure Description	Type	Account	Comments	GJ Savings Claimed	GJ Savings Verified	Life	2011 GJ Savings Estimated
GR Baker Memorial Hospital	MUA1 Heat Recovery Control	Controls; DDC	1178013 (premise 29750)	Calculations provided by Prism. Completion verified by site personnel.	196	196	10 years	82
GR Baker Memorial Hospital	MUA1 Hot Deck Supply Air Temperature Control Tune-Up	Mechanical and Controls	1178013 (premise 29750)	Calculations provided by Prism. Completion verified by site personnel.	24	24	10 years	10
UNBC Hospital	AHU 804 passing valve	Mechanical	1178013 (premise 824738)	Calculations provided by Prism. Completion verified by site personnel.	140	140	10 years	59
UNBC Hospital	Multizone Optimization	Mechanical/ Electrical	1178013 (premise 824738)	Calculations provided by Prism. Completion verified by site personnel.	670	670	10 years	281
UNBC Hospital	Optimize Heat Recovery Controls on MZ2 and SF 402	Electrical system	1178013 (premise 824738)	Calculations provided by Prism. Completion verified by site personnel.	1600	1600	10 years	672
UNBC Hospital	SF314 Zone Isolation	Mechanical/ Electrical	1178013 (premise 824738)	Calculations by proprietary macro not provided by Prism; Verified by separate calculation. Completion verified by site personnel.	1200	1070	10 years	449
UNBC Hospital	Install New Heat Recovery Coil on AHU404	Mechanical/ Electrical	1178013 (premise 824738)	Calculations provided by Prism. Completion verified by site personnel.	670	670	10 years	281

2011 Savings estimates are based on the proportion of HDD's between when the work was reported to be completed (June 2011), and December 31st 2011.

Methodology of Verification:

- The ES was interviewed to determine his role in initiating the measures
- It was determined the measures would not have occurred without the ES's actions
- The supplied reports were compared with the table of measures
- Additional potential measures were sought from the reports, ES interview and site personnel
- GJ calculations in the supplied spreadsheets were verified
- In some cases clarification was sought and received from the individuals who performed the calculation
- For a calculation which was not given (proprietary formula), a separate rough calculation was performed to verify it.
- Site personnel were contacted to verify that the measures had indeed been implemented and appeared to function as described.

ES quarterly reports were not supplied to ClearLead.

APPENDIX C: FORTISBC NPV CALCULATION

NPV Gas Savings = PV (discount rate, measure life, annual gas savings adjusted for free rider)

- Annual gas savings adjusted for free rider = annual verified gas savings (GJ/year) x (100% - free rider rate).
- Discount rate = 7.79%
- Measure Life was either provided by FortisBC or estimated by Prism Engineering
- The free rider rate was not available for all measure categories. As such, the free rider rate was only applied where available as show in table below.

Project Category	Measure Life	NTG Ratio provided by Jady Peng	Comment Prism Engineering
Dishwasher Replacement	12	100%	Life expectancy from US Applicance Industry (Market Value, Life Expectancy & Replacement Picture 2006-2013) http://www.researchandmarkets.com/research/af298a/u_s_appliance_ind http://www.mrappliance.com/expert/life-guide/
Instantaneous Water Heater	12	100%	http://www.fortisbc.com/NaturalGas/Homes/AppliancesAndEquipment/WaterHeaters/Pages/Types-of-water-heaters.aspx
Controls	3	100%	Various control measures such as reduction of DHW setpoint, Demand Controlled Ventilation,... Free Rider Rate was not available, therefore set to 0%
Replacement of Flow Fixture	8	73%	Jady provided two different set of measure life and NTG ration for this project category (the other one was 5 years with an NTG of 73%).
Maintenance & Repair (Valve)	5	100%	Passing valve was identified and repaired Free Rider Rate was not available, therefore set to 0%
Installation of Heat Recovery	10	100%	ASHRAE service life of heat exchanger 24 years. HR system is a retrofit system is a non critical system (not required for building operation). Generally we make the overvation that the persistency of such a measure is significantly lower than the service life of the actual equipment. Free Rider Rate was not available, therefore set to 0%
DHW Tank Isolation	10	100%	Site condition pre: two DHW tanks were installed which was a significantly oversized system. Site condition post: one DHW tank was isolated which saves natural gas as the heat loss through the 2nd tank can be avoided. Free Rider Rate was not available, therefore set to 0%
Installation of Domestic Hot Water Tank	12	100%	http://www.fortisbc.com/NaturalGas/Homes/AppliancesAndEquipment/WaterHeaters/Pages/Types-of-water-heaters.aspx
Solar Hot Water	10	100%	Service life of SHW system was estimated with 25 years. A SHW retrofit system is a non critical system (not required for building operation). Generally we make the overvation that the persistency of such a measure is significantly lower than the service life of the actual equipment.
Piping Insulation	20	95%	

2011 Projects

Measure Code	Organization	Project Name	Verified Gas Savings (GJ/year)	NTG	Gas Savings adj for Free Rider (GJ/year)	Measure Life (years)	NPV of GJ Savings
BCIT_2011_ECM2	BCIT	Sustainability Precinct Special Project: NE-04 DDC Control Recommissioning (Heat Doctor Pilot)	706	100%	706	3	1,826
Nvan_2011_ECM4	District of N. Van	Parkgate CC Solar Hot Water	75	100%	75	10	510.8
NHA_2011_ECM1	NHA	GR Baker - MUA1 Heat Recovery Control	196	100%	196	3	507.0
NHA_2011_ECM2	NHA	GR Baker - MUA1 Hot Deck Supply Air Temperature Control Tune-Up	24	100%	24	3	62.1
NHA_2011_ECM3	NHA	UHNBC -AHU 804 passing valve	140	100%	140	5	562.1
NHA_2011_ECM4	NHA	UHNBC -Multizone optimization	670	100%	670	3	1,733.2
NHA_2011_ECM5	NHA	UHNBC -Optimize heat recovery controls on MZ2, SF402	1,600	100%	1,600	3	4,139.0
NHA_2011_ECM6	NHA	UHNBC -SF314 zone isolation – fourth floor	1,070	100%	1,070	3	2,768.0
NHA_2011_ECM7	NHA	UHNBC -Install new heat recovery coil on AHU 405	670	100%	670	10	4,538.7
SFU_2011_ECM1	SFU	DHW Tank Isolation in AQ MR1027	5	100%	5	10	33.9
SFU_2011_ECM4	SFU	Library DHW Tank Setpoint Reduction	11	100%	11	3	28.5
SFU_2011_ECM5	SFU	Library Faucet Aerator	233	73%	170	8	985.3
SFU_2011_ECM6	SFU	ASB Faucet Aerator	80	73%	58	8	338.3
SFU_2011_ECM9	SFU	West Mall Complex DHW Setback and Tank Isolation	36	100%	36	3	93.1
UBC_2011_ECM3	UBC	C.Op. Pilot - N. Scarfe	2,635	100%	2,635	3	6,816.5
VIHASouth_2011_ECM3	VIHA South	Pre-Rinse Spray Valves, eight sites	576	73%	420	8	2,435.7
		2011 Projects Total	**8,151**	**99%**	**8,067**		**24,943**

2012 Projects

Measure Code	Organization	Project Name	Verified Gas Savings (GJ/year)	NTG	Gas Savings adj for Free Rider (GJ/year)	Measure Life (years)	PV of NG cost savings (over measure life)	NPV of GJ Savings
BCIT_2012_ECM3	BCIT	Potwasher Replacement #2	155	100%	155	12	$9,346	1,181
IHA_2012_ECM1	IHA	Cottonwoods Domestic Hot Water	71	100%	71	12	4,281.1	541
SFU_2012_ECM1	SFU	TASC 1 Weather Predictor	11	100%	11	3	225.2	28
SFU_2012_ECM2	SFU	Shrum Science Faucet Aerator	160	73%	117	8	5,354.8	677
SFU_2012_ECM3	SFU	South Science Building Faucet Aerator	55	73%	40	8	1,840.7	233
SFU_2012_ECM4	SFU	West Mall Complex Demand Controlled Ventilation	135	100%	135	3	2,763.9	349
SFU_2012_ECM5	SFU	Maggie Benston Centre Weather Predictor	35	100%	35	3	716.6	91
SFU_2012_ECM6	SFU	Install a Timer for the Hot Water Pump in the Diamond Alumni Centre	0	100%	0	3	0.0	0
SFU_2012_ECM7	SFU	Maggie Benston Building Demand Control Ventilation	199	100%	199	3	4,074.2	515
SFU_2012_ECM9	SFU	Robert C Brown Hall Faucet Aerators	103	73%	75	8	3,447.1	436
SFU_2012_ECM11	SFU	Energy Efficient Nozzle for Mackenzie Café	60	73%	44	8	2,008.0	254
SFU_2012_ECM12	SFU	Energy Efficient Nozzle for Dining Hall	97	73%	71	8	3,246.3	410
		2012 Projects Total	**1,081**	**88%**	**953**		**$37,304**	**4,713**

APPENDIX D: PROJECT REVIEW FORMS

Reference No. (assigned by Prism)

Company / Organization:

Site: please fill out

Date when this form was filled out: please fill out

Energy Specialist:

Project Name:

Description / Measure Type:

Natural Gas Account number through which the building is served and savings are being realized.

FortisBC Account Number: please fill out

Comments:

Please indicate the Reference Number in the email subject when providing the supporting documentation for this project. Do not send supporting documents for other measures in the same email!

ECM Description:

Write a brief description of the pre retrofit system(s) configuration, operation, operational requirements and identified energy savings opportunity.

Write a brief description of what was done.

<u>Fuel Savings Calculation</u>:

Provide a copy of the fuel savings calculation in excel format including a list of assumptions. If the measure was identified and quantified through consultants provide their calculation.

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	equipment capacities
☐	☐	☐	estimated annual load profiles
☐	☐	☐	estimated existing and retrofit fuel consumption
☐	☐	☐	other applicable supporting documentation

<u>Supporting Documentation:</u>

Where applicable also provide supporting documentation for the natural gas consuming equipment for which savings are reported such as:

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	Equipment data sheets including make and model of pre and post boilers
☐	☐	☐	System single line diagrams and schematics of heating plant
☐	☐	☐	DDC system graphic screens showing the heating plant
☐	☐	☐	trend log of return water temperature (minimum last 2 weeks)
☐	☐	☐	If possible include photos of the relevant equipment (name plate of post retrofit boilers)

Reference No. (assigned by Prism)

Company / Organization:

Site: please fill out

Date when this form was filled out: please fill out

Energy Specialist:

Project Name:

Description / Measure Type:

Natural Gas Account number through which the building is served and savings are being realized.

FortisBC Account Number: please fill out

Comments:

Please indicate the Reference Number in the email subject when providing the supporting documentation for this project. Do not send supporting documents for other measures in the same email!

ECM Description:

Write a brief description of the system(s) configuration, operation and operational requirements of the AHU's where coil cleaning was performed.

Write a brief description of the AHU's where the coil cleaning was performed include information such as :

- Specification of AHU (cfm, fan horse power, make and model,…)
- Heating system of AHU (is it an indirectly gas fired system, input BTU, include photos of the name plates of the units)
- Areas served with operating hours, setpoints in these spaces…

Fuel Savings Calculation:

Provide a copy of the fuel savings calculation in excel format including a list of assumptions. If the measure was identified and quantified through COp or consultants provide their calculation.

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	weekly & annual operating schedules
☐	☐	☐	equipment capacities
☐	☐	☐	estimated annual load profiles
☐	☐	☐	estimated existing and retrofit fuel consumption
☐	☐	☐	other applicable supporting documentation

Supporting Documentation:

Where applicable also provide supporting documentation for the natural gas consuming equipment for which savings are reported such as:

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	Equipment data sheets
☐	☐	☐	Air balancing reports
☐	☐	☐	System single line diagrams
☐	☐	☐	DDC system • graphic screens • trend data • sequence of operation and program code • point/variable values
☐	☐	☐	Include photos of the relevant equipment (name plates of AHU)

Reference No. (assigned by Prism)

Company / Organization:

Site: please fill out

Date when this form was filled out: please fill out

Energy Specialist:

Project Name:

Description / Measure Type:

Natural Gas Account number through which the building is served and savings are being realized.

FortisBC Account Number: please fill out

Comments:

Please indicate the Reference Number in the email subject when providing the supporting documentation for this project. Do not send supporting documents for other measures in the same email!

ECM Description:

Write a brief description of the pre retrofit system(s) configuration, operation, operational requirements and identified energy savings opportunity.

Write a brief description of what was done, the existing system (kitchen exhaust and make up air unit) and the installed demand control system.

<u>Fuel Savings Calculation</u>:

Provide a copy of the fuel savings calculation in excel format including a list of assumptions. If the measure was identified and quantified through COp or consultants provide their calculation.

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	weekly & annual operating schedules
☐	☐	☐	equipment capacities (kitchen exhaust and make up air unit)
☐	☐	☐	estimated annual load profiles (including cooking profile for the kitchen where the DCV was installed)
☐	☐	☐	estimated existing and retrofit fuel consumption
☐	☐	☐	other applicable supporting documentation

<u>Supporting Documentation:</u>

Where applicable also provide supporting documentation for the natural gas consuming equipment for which savings are reported such as:

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	Equipment data sheets
☐	☐	☐	Air balancing reports
☐	☐	☐	System single line diagrams
☐	☐	☐	DDC system • graphic screens • trend data • sequence of operation and program code • point/variable values
☐	☐	☐	If possible include photos of the relevant equipment

Reference No. (assigned by Prism)

Company / Organization:

Site: please fill out

Date when this form was filled out: please fill out

Energy Specialist:

Project Name:

Description / Measure Type:

Natural Gas Account number through which the building is served and savings are being realized.

FortisBC Account Number: please fill out

Comments:

Please indicate the Reference Number in the email subject when providing the supporting documentation for this project. Do not send supporting documents for other measures in the same email!

ECM Description:

Write a brief description of the pre retrofit system(s) configuration, operation, operational requirements and identified energy savings opportunity.

Write a brief description of what was done.

<u>Fuel Savings Calculation</u>:

Provide a copy of the fuel savings calculation in excel format including a list of assumptions. If the measure was identified and quantified through COp or consultants provide their calculation.

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	weekly & annual operating schedules
☐	☐	☐	equipment capacities
☐	☐	☐	estimated annual load profiles
☐	☐	☐	estimated existing and retrofit fuel consumption
☐	☐	☐	other applicable supporting documentation

<u>Supporting Documentation:</u>

Where applicable also provide supporting documentation for the natural gas consuming equipment for which savings are reported such as:

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	Equipment data sheets
☐	☐	☐	Air balancing reports
☐	☐	☐	System single line diagrams
☐	☐	☐	DDC system • graphic screens • trend data • sequence of operation and program code • point/variable values
☐	☐	☐	If possible include photos of the relevant equipment

Reference No. (assigned by Prism)

Company / Organization:

Site: please fill out

Date when this form was filled out: please fill out

Energy Specialist:

Project Name:

Description / Measure Type:

Natural Gas Account number through which the building is served and savings are being realized.

FortisBC Account Number: please fill out

Comments:

Please indicate the Reference Number in the email subject when providing the supporting documentation for this project. Do not send supporting documents for other measures in the same email!

ECM Description:

Write a brief description of the pre retrofit system(s) configuration (i.e. number of DHW tanks, number of recirculation pumps, boiler or natural gas fired DHW tanks,…), operation (temperature setpoints,….), operational requirements and identified energy savings opportunity.

Write a brief description of what was done.

Fuel Savings Calculation:

Provide a copy of the fuel savings calculation in excel format including a list of assumptions. If ECM was identified and quantified through COp or consultants please provide their calculation.

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	weekly & annual operating schedules
☐	☐	☐	equipment capacities (tanks sizes, rated MBH inputs for gas fired DHW tanks,…)
☐	☐	☐	estimated annual load profiles
☐	☐	☐	description of pre and post control strategy and setpoints
☐	☐	☐	for piping insulation measure provide pipe length, diameter, existing insulation, retrofit insulation, hot water service
☐	☐	☐	estimated existing and retrofit fuel consumption
☐	☐	☐	other applicable supporting documentation

Supporting Documentation:

Where applicable also provide supporting documentation for the natural gas consuming equipment for which savings are reported such as:

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	Equipment data sheets
☐	☐	☐	Flow balancing reports
☐	☐	☐	Piping schematic, plumbing drawings to explain DHW system configuration
☐	☐	☐	DDC system if the system for which the retrofit was carried out is controlled by DDC • graphic screens • trend data • sequence of operation and program code • point/variable values
☐	☐	☐	If possible include photos of the relevant equipment

Reference No. (assigned by Prism)

Company / Organization:

Site: please fill out

Date when this form was filled out: please fill out

Energy Specialist:

Project Name:

Description / Measure Type:

Natural Gas Account number through which the building is served and savings are being realized.

FortisBC Account Number: please fill out

Comments:

Please indicate the Reference Number in the email subject when providing the supporting documentation for this project. Do not send supporting documents for other measures in the same email!

ECM Description:

Write a brief description of the installed solar hot water system and include information such as

- Total number of installed panels
- Make and Model of installed panels
- Unglazed, glazed or evacuated solar hot water panels
- Building type (hospital, office), number of beds, number of occupants
- Orientation of panels (please provide a building plan showing north and draw the location of the panels on it)
- Storage tank as buffer if yes provide number and the capacity of tank(s)

<u>Fuel Savings Calculation</u>:

Provide a copy of the fuel savings calculation in excel format including a list of assumptions. If the measure was identified and quantified through COp or consultants provide their calculation.

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	weekly & annual occupancy schedules of the concerning spaces
☐	☐	☐	Number of occupants, or beds with occupancy rate
☐	☐	☐	Calculation spreadsheets
☐	☐	☐	estimated existing and retrofit fuel consumption
☐	☐	☐	operating conditions (i.e hot water temperature setpoints…)
☐	☐	☐	other applicable supporting documentation

<u>Supporting Documentation:</u>

Where applicable also provide supporting documentation for the natural gas consuming equipment for which savings are reported such as:

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	Product specification of solar panels
☐	☐	☐	Product Specification of storage tank(s)
☐	☐	☐	Roof plan showing the orientation of solar panels
☐	☐	☐	Photos

Reference No. (assigned by Prism)

Company / Organization:

Site: please fill out

Date when this form was filled out: please fill out

Energy Specialist:

Project Name:

Description / Measure Type:

Natural Gas Account number through which the building is served and savings are being realized.

FortisBC Account Number: please fill out

Comments:

Please indicate the Reference Number in the email subject when providing the supporting documentation for this project. Do not send supporting documents for other measures in the same email!

ECM Description:

Write a brief description of the pre retrofit system(s) configuration (flow rates), operation (estimated usage), any operational requirements and identified energy savings opportunity.

Write a brief description of what was done including information such as type of plumbing/flow fixtures which were retrofitted, usage, location, date of replacements….

Fuel Savings Calculation:

Provide a copy of the fuel savings calculation in excel format including a list of assumptions. If the measure was identified and quantified through COp or consultants provide their calculation.

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	weekly & annual occupancy schedules of the concerning spaces
☐	☐	☐	flush and flow rates of pre and post retrofit plumbing/flow fixtures
☐	☐	☐	count of the fixtures which were retrofitted
☐	☐	☐	estimated existing and retrofit fuel consumption
☐	☐	☐	operating conditions (i.e hot water temperature setpoints…)
☐	☐	☐	other applicable supporting documentation

Supporting Documentation:

Where applicable also provide supporting documentation for the natural gas consuming equipment for which savings are reported such as:

Provided	not available	not relevant *(double click check box to check or uncheck the box)*	
☐	☐	☐	Cut sheets of aerators, shower heads, pre rinse water valves, for all the replacements)
☐	☐	☐	If possible include photos of the relevant equipment if any equipment is more complex

APPENDIX E: CONTACT LIST ENERGY SPECIALISTS

Customer:	Energy Specialist Name	FortisBC Account Manager	Energy Manager / Contact Name	Energy Specialist Phone #	Energy Specialist Email
District of North Vancouver	Paul Forsyth	Doug Taber	Dominica Babicki	604-990-2254	forsythp@dnv.org
Capilano University	Mariko Fuchihara ***contract is finishing and won't be renewed**	Doug Taber	Laura Williams	604-990-7986	marikofuchihara@capilanou.ca
University of BC	Lillian Zaremba	Doug Taber	Orion Henderson	604-827-3441	lillian.zaremba@ubc.ca
BCIT	TBD	Doug Taber	Alexandre Hebert		
VIHA - South	Claudette Poirier	Nancy Myers	Deanna Fourt	250-370-8111, 13708	claudette.poirier@viha.ca
PHSA	Victor Benitez	Nancy Myers	Mauricio Acosta	604-875-3006	vbenitez@cw.bc.ca
NHA	Keith Hebert	Nancy Myers	Albert Sommerfeld	604-636-2180 /250-277-4960	keith.hebert@northernhealth.ca
School District #38 (Richmond)	Dina Mously ***NEW**	Doug Taber	Tracy Blagdon	604-668-6000 (ext. 6006)	dmously@sd38.bc.ca
BCAOMA	Natalie Yao	Wes Nienaber	Marg Gordon	604-733-9440	nyao@bcaoma.com
Simon Fraser University	Bernard Chan	Doug Taber	Ron Sue	W: 778-782-9288 H:604.728.5225	b_chan@sfu.ca
VIHA - Central	Bjorn Richt	Nancy Myers	Deanna Fourt	778-386-6244	Bjorn.Richt@viha.ca
BC Housing	Jamee DeSimone	Mandy Assi	Jennifer Sanguinetti	604-454-5440	jdesimone@bchousing.org
School District #37 (Delta)	Debra Eng	Doug Taber	Jim White	604 946 5235	deng@deltasd.bc.ca
Interior Health Authority	Greg McMurray	Nancy Myers	Ted Spearin	250-491-6496	greg.mcmurray@interiorhealth.ca
Vancouver Coastal Health	Alan Lin	Nancy Myers	Mauricio Acosta	604-250-4365	alan.lin2@vch.ca
School District #41 (Burnaby)	Josh Munro	Doug Taber	Matt Foley	604-664-8427	josh.munro@sd41.bc.ca
VIHA - North	Kevin Ramlu	Nancy Myers	Deanna Fourt	250-331-8505 ext.68349	kevin.ramlu@viha.ca

InterVISTAS

REPORT: FortisBC Switch N' Shrink Program Carbon Emissions and Cost Savings Analysis




Prepared for

FortisBC

Prepared by

Inter*VISTAS* Consulting Inc.

Final Version

21 November 2012

1. Technical Analysis Overview

The objective of technical analysis is to compare annual customer usage of heating oil versus natural gas for the following:

- Energy consumption/efficiency in gigajoules (GJ)
- Consumer costs in dollars ($)
- Greenhouse gas emissions in carbon dioxide equivalent (CO2e)

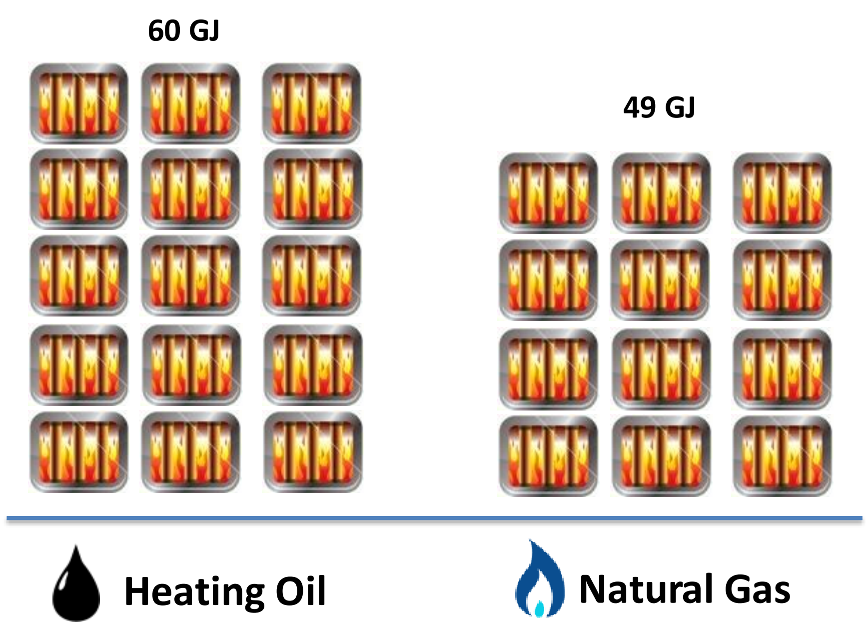
Actual customer heating oil bills/data were requested.

FortisBC natural gas usage and invoice data were similarly used.

Approximately 70 respondents, but records only analyzed when 12 consecutive whole months of data were available for both heating oil and natural gas.

The data was normalized to obtain annual usage, cost, and emissions amounts comparisons for 31 customers.

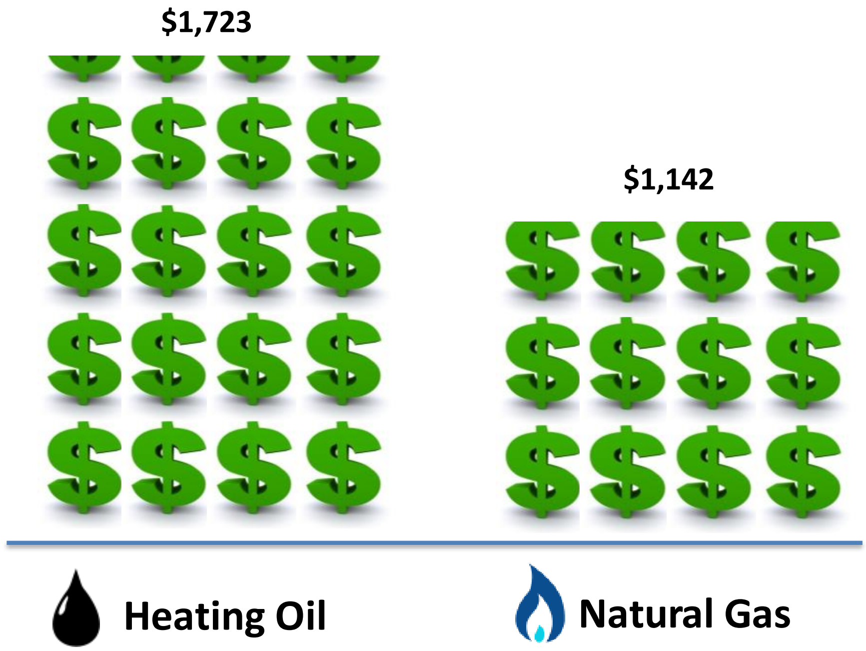
1.1 Energy Consumption Results



↓ 11 GJ average annually

7% less energy use per customer, on average, due to better efficiency of natural gas

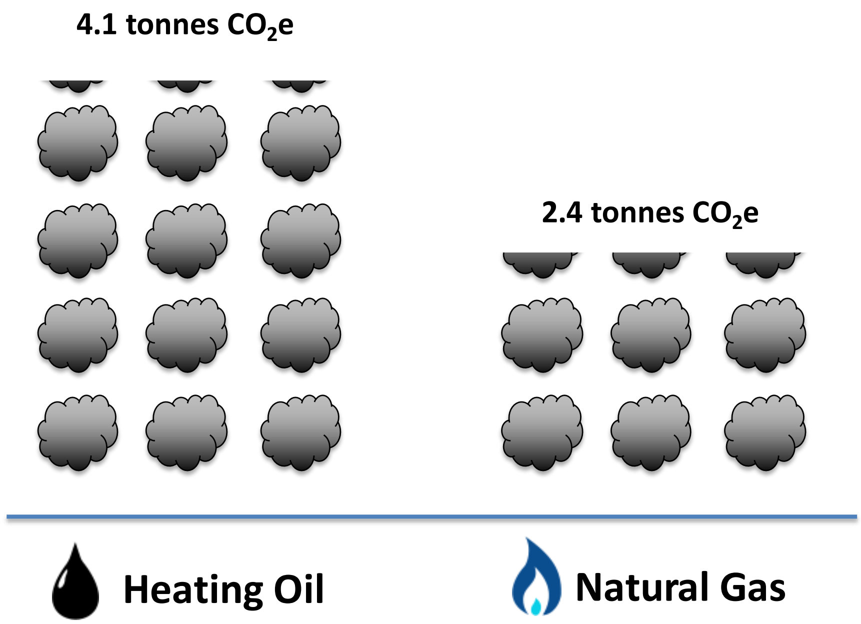
1.2 Consumer Savings Results



↓ $582 average annually

20% average consumer cost savings from lower fuel price and use

1.3 Greenhouse Gas Emissions Results



↓ ~1.6 tonnes carbon dioxide equivalent average annually

31% average household reduction in carbon emissions from much cleaner burning natural gas

2. Calculation Methodology

The following methodology was used to calculate the greenhouse gas emissions improvements for the FortisBC customers who made a switch from heating oil to natural gas. The normalized annual carbon dioxide equivalent (CO_2e), dollar savings, and energy usage were estimated.

Typical seasonal heating usage was calculated by totalling the FortisBC normalized natural gas consumption volumes by month and expressing them as a percentage of the total.

For each individual survey respondent, these specific steps were taken:

1) Note heating oil refill dates, amount (L), and amount paid ($);
2) Count the number of months to previous refill (pro-rating usage within the month of the oil refill date) and sum the annual percentage of use that the refill represents;
3) Use the percentage to determine the weighted average monthly oil usage (L) and weighted average monthly cost ($) (weighted average was determined by multiplying the seasonal monthly percentage and dividing by the sum of those seasonal monthly percentages since the last refill date accounting for day of month);
4) Ensure that there are 12 months' of continuous heating oil usage data (using the most recent 12 months only);
5) Look up the normalization factor by region, rate class, and date for the specific months in question;
6) Divide the month's weighted average usage by the month's normalization factor to get normalized heating oil consumption (L) (along with energy consumption in GJ) and normalized heating oil cost ($);
7) Multiply the normalized heating oil consumption amount (L) by the heating oil emission factor (kg/L) to get heating oil CO_2e emissions (kg);
8) Use the earliest 12 continuous months of normalized natural gas consumption data (GJ) and normalized natural gas cost ($);
9) Multiply the normalized natural gas consumption amount (GJ) by the natural gas emission factor (kg/GJ) to get natural gas CO_2e emissions (kg);
10) Total the CO_2e emissions (kg) and normalized costs ($) for 12 months for both heating oil and natural gas; and
11) Subtract the total normalized costs ($), CO_2e emissions (kg), and energy usage (GJ) of natural gas from heating oil to get the total savings (if either number is negative, it means that heating oil was more advantageous).

2.1 Emission Factors Source

The emission factors for both heating oil and natural gas are those recommended by the BC Climate Action Secretariat from "Methodology for Reporting B.C. Local Government Greenhouse Gas Emissions, version 2.0" released in December 2011. See Stationary Sources, Direct Emissions: Stationary Fuel Combustion - Table 1 and 2. The primary sources for these emission factors are: 1) British Columbia (2011). British Columbia Greenhouse Gas Inventory Report 2008, pp. 62-63 and 2)

Environment Canada (2011). National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990-2009, Annex 8 pp. 191-205.

2.2 Energy Conversion Rate

The energy usage of heating oil (in litres) was converted to gigajoules (GJ) using Natural Resources Canada definition/conversion rate

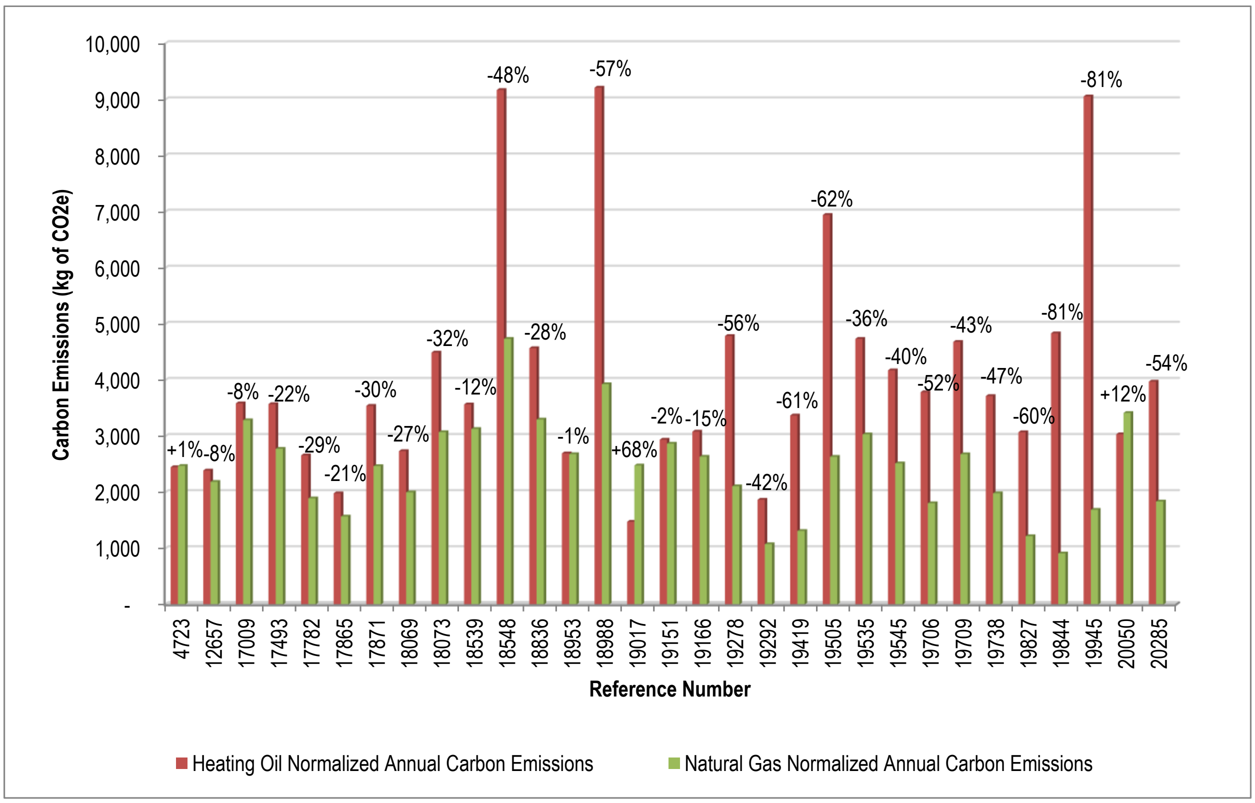
3. Results

3.1 Carbon Emissions Results

Of 62 respondents with data inputted in the online version of the survey, 31 responses had adequate data to be evaluated for emissions (i.e. 12 continuous months of heating oil and natural gas usage with no apparent data gaps). Of the remaining 31 unusable responses; 18 were due to insufficient heating oil data, 7 were due to missing elements within the heating oil data, and 6 were due to insufficient natural gas data. All results were from residential properties. For the usable responses, six were from the Lower Mainland while the other 25 were from Vancouver Island.

The average **CO2e reduction was 1,628 kg** and the average percentage CO2e emissions improvement was **31%**. The range of emissions change from heating oil to natural gas was from a negative impact of 68% up to an improvement of 81% with a standard deviation of 30%.

The following chart provides a summary of the carbon emissions savings. The percentages above each bar show the percentage change.



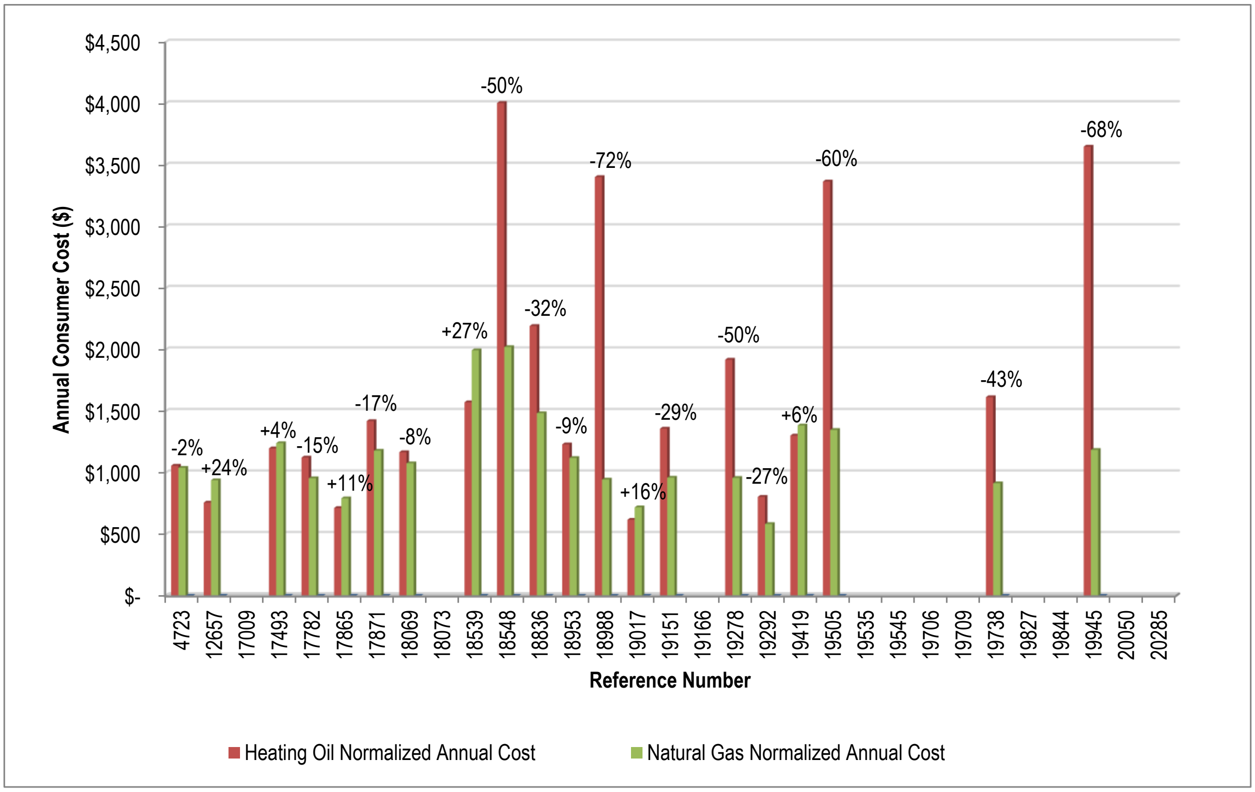
InterVISTAS

3.2 Cost Savings Results

Of the 31 cases that could be evaluated for emissions savings, 20 had adequate data (i.e. 12 continuous months of heating oil and natural gas cost data with no apparent data gaps) to calculate the consumer cost savings. Both the heating oil and natural gas bill amounts were normalized by month in order to provide a fair comparison.

The average annual **cost savings were $581.60 per yea**r and the average percentage cost savings from switching from heating oil to natural gas were **20%**. The change from heating oil to natural gas ranged from an increased cost of 27% to a cost saving of 72% with a standard deviation of 30%.

The following chart provides a summary of the annual cost savings. The percentages above each bar show the percentage change.

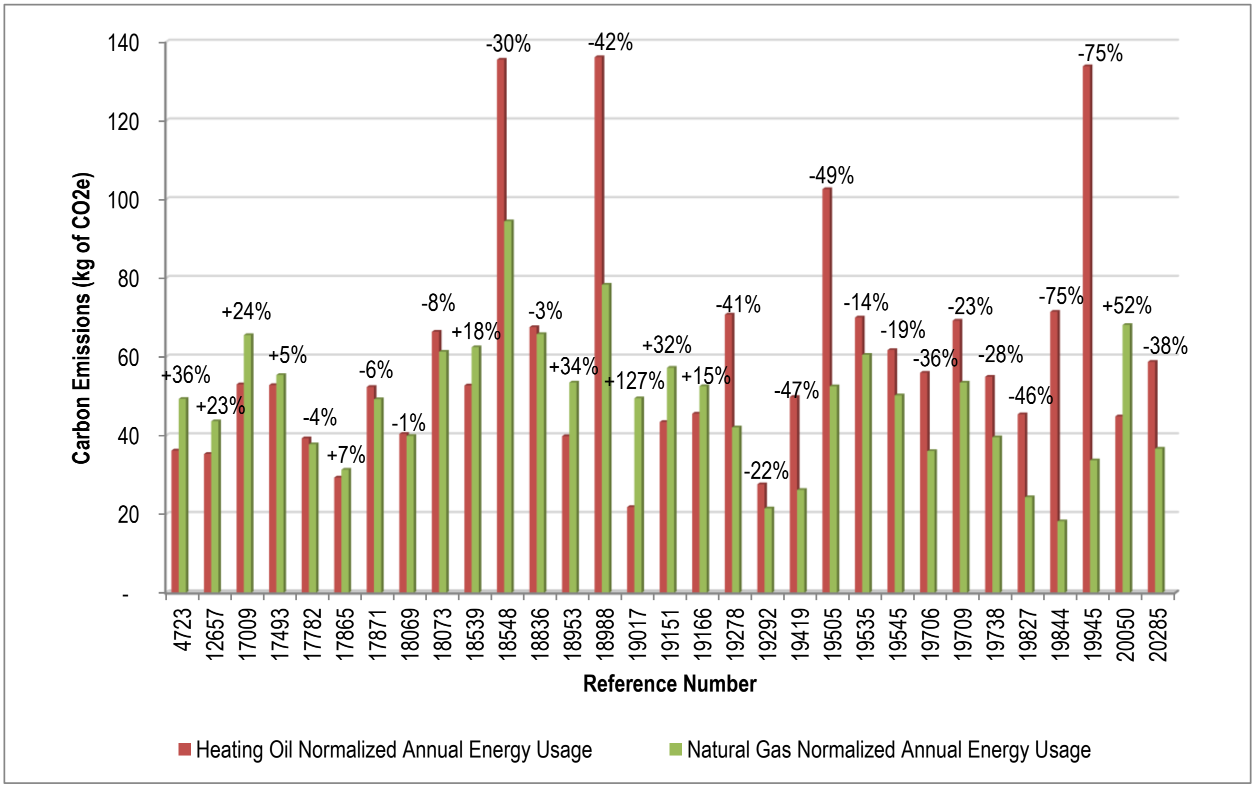


3.3 Energy Usage Results

The energy content of the normalized annual heating oil consumption was converted to gigajoules in order to compare energy usage.

The average annual **energy savings were 11.44 gigajoules per year** and the average percentage energy savings from switching from heating oil to natural gas were **7%**. The energy usage change from heating oil to natural gas ranged from an increased consumption of 127% to energy savings of 75% with a standard deviation of 41%.

The following chart provides a summary of the energy usage savings. The percentages above each bar show the percentage change.



3.4 Detailed Carbon Emissions and Cost Savings Results

			Heating Oil				Natural Gas									
RefNum	Rate Class	Region	Normalized Annual Usage (L)	Energy Used (GJ)	Normalized Annual Cost ($)	Normalized Annual CO_2e Emissions (kg)	Normalized Annual Usage (GJ)	Normalized Annual Cost ($)	Normalized Annual CO2e (kg)	Annual CO2e Emissions Reduction (kg)	% Emissions Change	Annual Cost Savings ($)	% Cost Change	Energy Savings (GJ)	% Energy Change
4723	VI-RGS	VI	932.82	36.19	$1,056.97	2,449.72	49.29	$1,039.68	2,472.55	(22.83)	+1%	$17.29	-2%	(13.10)	+36%
12657	VI-RGS	VI	910.29	35.32	$756.84	2,390.58	43.62	$939.16	2,187.84	202.74	-8%	$(182.32)	+24%	(8.30)	+23%
17009	RATE1	LML	1,366.22	53.01		3,587.91	65.52		3,286.63	301.29	-8%			(12.51)	+24%
17493	VI-RGS	VI	1,361.12	52.81	$1,197.82	3,574.52	55.37	$1,239.97	2,777.30	797.22	-22%	$(42.14)	+4%	(2.56)	+5%
17782	VI-RGS	VI	1,013.00	39.30	$1,123.16	2,660.29	37.77	$955.13	1,894.53	765.76	-29%	$168.03	-15%	1.53	-4%
17865	VI-RGS	VI	755.65	29.32	$713.49	1,984.46	31.31	$792.20	1,570.50	413.97	-21%	$(78.71)	+11%	(1.99)	+7%
17871	VI-RGS	VI	1,349.15	52.35	$1,419.57	3,543.09	49.22	$1,178.67	2,469.08	1,074.01	-30%	$240.90	-17%	3.12	-6%
18069	VI-RGS	VI	1,041.90	40.43	$1,166.93	2,736.20	39.90	$1,076.40	2,001.34	734.86	-27%	$90.53	-8%	0.53	-1%
18073	RATE1	LML	1,710.73	66.38		4,492.63	61.29		3,074.53	1,418.11	-32%			5.08	-8%
18539	VI-RGS	VI	1,358.92	52.73	$1,572.23	3,568.74	62.43	$1,994.66	3,131.27	437.47	-12%	$(422.43)	+27%	(9.70)	+18%
18548	VI-RGS	VI	3,492.34	135.50	$4,004.25	9,171.43	94.43	$2,021.06	4,736.67	4,434.76	-48%	$1,983.20	-50%	41.07	-30%
18836	VI-RGS	VI	1,740.63	67.54	$2,192.16	4,571.18	65.77	$1,483.50	3,299.10	1,272.08	-28%	$708.66	-32%	1.77	-3%
18953	VI-RGS	VI	1,026.86	39.84	$1,230.46	2,696.71	53.47	$1,120.05	2,681.86	14.85	-1%	$110.41	-9%	(13.62)	+34%
18988	RATE1	LML	3,508.67	136.14	$3,402.31	9,214.31	78.33	$944.23	3,929.00	5,285.31	-57%	$2,458.0	-72%	57.81	-42%
19017	RATE1	LML	562.56	21.83	$617.68	1,477.38	49.46	$718.62	2,480.70	(1,003.32)	+68%	$(100.94)	+16%	(27.63)	+127%
19151	VI-RGS	VI	1,119.50	43.44	$1,358.26	2,939.98	57.21	$959.53	2,869.66	70.32	-2%	$398.73	-29%	(13.77)	+32%
19166	VI-RGS	VI	1,174.23	45.56		3,083.72	52.54		2,635.63	448.09	-15%			(6.98)	+15%
19278	VI-RGS	VI	1,823.11	70.74	$1,918.86	4,787.78	42.06	$957.62	2,109.60	2,678.18	-56%	$961.24	-50%	28.68	-41%
19292	VI-RGS	VI	711.85	27.62	803.91	1,869.42	21.48	$582.92	1,077.67	791.75	-42%	$220.99	-27%	6.14	-22%
19419	VI-RGS	VI	1,283.70	49.81	$1,301.82	3,371.19	26.18	$1,384.06	1,313.19	2,058.00	-61%	$(82.23)	+6%	23.63	-47%
19505	VI-RGS	VI	2,644.50	102.61	$3,366.05	6,944.86	52.52	$1,347.59	2,634.21	4,310.65	-62%	$2,018.46	-60%	50.09	-49%
19535	RATE1	LML	1,803.83	69.99		4,737.14	60.51		3,034.94	1,702.20	-36%			9.48	-14%
19545	VI-RGS	VI	1,590.25	61.70		4,176.23	50.19		2,517.65	1,658.58	-40%			11.51	-19%
19706	RATE1	LML	1,441.95	55.95		3,786.79	36.04		1,807.81	1,978.98	-52%			19.91	-36%
19709	VI-RGS	VI	1,783.12	69.19		4,682.76	53.46		2,681.37	2,001.38	-43%			15.73	-23%
19738	VI-RGS	VI	1,415.71	54.93	$1,613.87	3,717.87	39.57	$914.06	1,984.92	1,732.94	-47%	$699.81	-43%	15.36	-28%
19827	VI-RGS	VI	1,170.34	45.41		3,073.50	24.33		1,220.43	1,853.06	-60%			21.08	-46%
19844	VI-RGS	VI	1,841.31	71.44		4,835.56	18.20		912.85	3,922.71	-81%			53.24	-75%
19945	VI-RGS	VI	3,449.30	133.83	$3,649.61	9,058.41	33.70	$1,185.24	1,690.58	7,367.83	-81%	$2,464.37	-68%	100.13	-75%
20050	VI-RGS	VI	1,156.25	44.86		3,036.48	68.09		3,415.39	(378.91)	+12%			(23.23)	+52%
20285	VI-RGS	VI	1,513.72	58.73		3,975.27	36.65		1,838.55	2,136.72	-54%			22.08	-38%

Prepared by
Inter*VISTAS* Consulting Inc.

Airport Square – Suite 550
1200 West 73rd Avenue
Vancouver, BC
Canada V6P 6G5

Telephone: 604-717-1800
Facsimile: 604-717-1818
www.intervistas.com

Attachment 216.1

EEC Advisory Group (EECAG)

Last Updated July 24, 2013		
	CONTACT	ORGANIZATION
1	Alison Thorson	BC Utilities Commission
2	Andrea Linsky	BC Non Profit Housing Assoc.
3	Andrew Pape-Salmon	RDH Building Engineering Ltd
4	Bruce Macgowan	IBC Technologies Inc.
5	Cindy Stern	Tseshaht First Nation
6	Craig Williams	Canadian Manufacturers & Exporters
7	Dan Pasacreta	Crosby Property Mgmts., Ltd.
8	David Craig	Commercial Energy Consumers Association of BC
9	David Hutniak	Rental Housing Council
10	Erik Kaye	Ministry of Energy and Mines
11	Eugene Kung	BC Public Interest Advocacy Centre
12	Gary Fabbro	EMCO Corporation BC, TECA
13	Gord Monro	Heating, Refrigeration and Air Conditioning Institute of Canada
14	Jeff Fisher	Urban Development Institute
15	Jennifer Sanguinetti	BC Housing
16	Joan Huzar	Consumers Council of Canada
17	Malcolm Bradbury	AO Smith and CIPH
18	Mark Hartman	City of Vancouver
19	Mark Sakai	Greater Vancouver Home Builders' Assoc.
20	Mike Todd	Canfor Pulp
21	Nina Winham	New Climate Strategies
22	Nir Kushnir	National Energy Equipment
23	Peter Love	Energy Services Assoc.
24	Rob Noel	BC Mechnical Contractors Assoc
25	Steve Hobson	BC Hydro
26	Terry Brace	Teck Resources
27	Tom Hackney	BC Sustainable Energy Assoc.
28	Tom-Pierre Frappé-Sénéclauze	Pembina Institute

FortisBC Energy Utilities'[1] ("FEU") Energy Efficiency and Conservation ("EEC") Advisory Group Terms of Reference ("ToR")

1 INTRODUCTION

The objective of the EEC Advisory Group ("EECAG") is to provide insight and feedback on FEU's portfolio of EEC activities. The FEU collectively form the largest natural gas distribution utility in BC, providing sales and transportation services to approximately 950,000 customers in more than 140 communities. The EECAG provides a mechanism for accountability and transparency on EEC spending and initiatives based on the British Columbia Utilities Commission's ("BCUC") Decision and Order No. G-036-09, which approved the increase in FEU's funding of EEC activity. BCUC directives contained in its Decision and in Order No. G-44-12, regarding FEU's 2012-13 Revenue Requirement Application ("RRA"), have also been taken into account in the development of these ToR. Accountability is provided through the complete, transparent and accurate reporting by FEU of EECAG activities, feedback and opinions within its submissions to the BCUC as appropriate.

The EECAG activities will provide a forum for stakeholders to engage in dialogue with FEU; however, FEU is ultimately responsible for the management of the EEC portfolio. It is FEU's objective to maintain a balance between obtaining advisory group feedback, appropriate accountability mechanisms and a reasonable burden of commitment among EECAG members.

2 CONTEXT

Energy policy at all levels of government is increasingly focused on energy conservation and efficiency, cleaner energy production, reducing greenhouse gas ("GHG") emissions and overall sustainability. FEU's EEC activities are designed to support these policies by promoting the efficient use of natural gas, reducing energy costs for customers and reducing GHG emissions.

Federal, Provincial and Municipal Regulations, Policies and Bylaws

FEU must conduct its operations, including EEC activity, in adherence to all federal and BC laws and regulations and within the context of both federal and provincial policies. Those regulations and policies most likely to affect EEC activities relate to energy, emissions, environment and safety. These include, but are not limited to, the BC *Utilities Commission Act*, the BC *Clean Energy Act*, the *Greenhouse Gas Reductions Targets Act,* the Provincial Building Code and the BC Demand-Side Measures Regulation.

[1] **FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc. and FortisBC Energy Inc. Fort Nelson Service Area will together be noted as FortisBC Energy Utilities (FEU) throughout the document.**

Regional and municipal bylaws and policies may also play a role in EEC programs and activities. For example, municipalities may enforce their own building by-laws or implement development guidelines that can have implications for EEC programs in those municipalities.

BC Utilities Commission

The BCUC is a regulatory agency of the Provincial Government. It operates under and administers the *Utilities Commission Act* ("UCA"), and can be issued instructions from the Provincial Government by way of Special Directions. The BCUC's mission is to ensure that ratepayers receive safe, reliable, and nondiscriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital.

FEU must adhere to directives and orders from the BCUC that may be included in its decisions on a range of FEU submissions and applications, most notably FEU's RRA, Long Term Resource Plan ("LTRP") submission, other EEC funding applications and any EEC related special inquiries initiated by the BCUC.

3 PURPOSE & OBJECTIVES

The EECAG is intended to act as an advisory body. It cannot make decisions that are binding on FEU. The purpose of the EECAG is to:

- Review and provide feedback to FEU on a range of EEC related issues and activities, including:
  - Information and reports presented by FEU
  - Demand Side Management ("DSM") planning
  - EEC program and portfolio performance
  - EEC program development and design (e.g. goals, assumptions, inputs, incentives and terms and conditions)
  - Funding transfers
  - FortisBC's Evaluation, Measurement and Verification ("EM&V") Framework
  - The EECAG ToR
- Consider other issues and activities as they may arise. Review, understand and advise FEU on energy and emissions policy and regulations at all levels of government that may impact its EEC activities
- Bring forward any new ideas for EEC related activities that might be included in FEU's EEC portfolio of activities
- Provide unique perspectives and expertise representing a broad range of stakeholders
- Create an open dialogue between stakeholders, increasing understanding of EEC issues and facilitating partnerships
- Carry all pertinent information from EECAG activities back to members' respective organizations for dissemination and consideration as appropriate

- Improve the efficiency of program deployment by acting as a centralized mechanism for stakeholder review and input into a range of EEC issues

4 SCOPE

The EEC Stakeholder Group may be asked to review, discuss and provide feedback on any aspect of the EEC portfolio or particular EEC program. It is FEU's intention that EECAG members provide insight and feedback that will inform the EEC portfolio. FortisBC does not intend participation in the EECAG to represent explicit approval or support from individual members with respect to specific initiatives or plans that may be included in an application or submission to the BCUC for which the Commission sets out a formal regulatory proceeding. FortisBC recognizes and advises EECAG members that they may participate in such proceedings and convey their positions or those of their organizations on any EEC planning issue without prejudice during such process.

5 MEMBERSHIP

The EECAG is intended to be a consortium representing the broad constituency of FEU stakeholders. Members may be appointed based on their personal capacity (i.e. independent experts), representation of a common interest shared by stakeholders or representation of a particular organization/group (including but not limited to governments, regions, First Nations, customers, suppliers, industries, non-government organizations and research institutes). While the number of members and interest groups they represent is not specifically set, a periodic review will be conducted to assess the adequacy and appropriateness of representation within the EECAG.

The optimum number of EECAG members is 35. Membership on the EECAG is to be formalized by each member signing a copy of these ToR and returning same to FEU. Only one person from any one organization may typically sit as a member of the EECAG. Membership to the EECAG cannot be transferred by members, though members may occasionally appoint someone from their own organization to attend in their place with prior notification to FEU.

Once the initial EECAG membership is set following the adoption of the final ToR, the process for identifying and inducting new members is:

- Prospective members will submit in writing (letter or email) a request to join the EECAG, stating their name, organization, contact information and reasons for wanting to join the EECAG.
- Prospective members will be considered by FEU. Input from the Independent Facilitator (See Section 6) and/or EECAG members will be considered, but the final decision will rest with FEU.
- Membership will be formalized by the signing of these ToR.
- In the case where a member leaves the organization they are representing a review will be conducted by FEU to determine:

- If that person should remain a member of the EECAG
- If an alternative person from that organization should be chosen to join the EECAG (with prior agreement by both that organization and FortisBC and providing the membership requirements are met)
- If that seat should be vacated and made available for a potential new member

FEU recognizes that in some cases it is the participation of an influencer within an organization that is important to the FEU-EECAG objectives, while in other cases it may be the expertise and experience of an individual that is desired, provided that individual remains engaged in the energy efficiency field. This aspect will be considered in the review.

Members who are consistently absent, fail to participate or do not adhere to these ToR may be asked to leave the EECAG.

Open and frank discussion within the EECAG is important for the group to function effectively. To facilitate such discussion, members must recognize that an individual's comments cannot always be assumed to represent the formal position of their organization. It is therefore important that the discussions held within the EECAG workshops and other forums balance the need for confidentiality in some situations with the need to share information in other situations. As such, FEU will strive to create an environment of trust among EECAG members built on mutual respect, freedom of opinion and equal opportunity to participate.

6 INDEPENDENT FACILITATOR

In addition to regular EECAG members, FEU will appoint an Independent Facilitator (see RESPONSIBILITIES). The Independent Facilitator will:

- Act as an advisor to FEU for the planning of EECAG activities
- Act as an advisor to FEU in its review of the adequacy and appropriateness of interest group representation on the EECAG
- Facilitate workshop sessions in which FEU is seeking input from the EECAG to ensure that all stakeholders have a fair and balanced opportunity to understand issues and provide input
- Act as an advisor to FEU in its communications with the EECAG on how input and feedback from the EECAG has been utilized by FEU

7 MEETINGS and FEEDBACK

FEU expects to hold a minimum of two meetings a year to discuss EEC issues and initiatives. These two meetings will typically occur in the spring and fall; however, special meetings may be requested by FEU as needed in order to obtain EECAG feedback on more pressing issues. This includes any activities that will require BCUC approval such as funding transfers or introducing new programs not identified in the approved DSM plan. Meetings may be in person at a central location or via remote communication such as conference calling and/or via internet based meeting tools.

FEU recognizes that EECAG member time is valuable and that meetings need to be conducted in order to maximize group feedback rather than simply presenting information. As such, FEU will endeavor to use a workshop format whenever practical to facilitate meaningful feedback, and to have pre-reading materials for meetings available approximately 2 weeks prior to the meeting to allow sufficient review time. FEU may also solicit feedback from the EECAG in other forms, including electronic communication and telecommunication methods.

When planning for an upcoming EECAG meeting, if FEU, in consultation with the Independent Facilitator, determines that issues to be dealt with do not require an in-person, full meeting of the EECAG and would more appropriately be addressed through a different mechanism such as a teleconference meeting or an email package of information and feedback, FEU may choose not to hold one of the regular semi-annual meetings. Reasons for choosing another mechanism to provide information and gain feedback will be provided by FEU to the EECAG.

FEU commits to keeping EECAG members informed about the results of any feedback sought from the EECAG, how FEU interprets those results and the outcomes of any issues the EECAG is asked to advise on. Although not all EECAG requests/feedback will necessarily be adopted, all feedback will be considered and FEU will do its best to report the interests and opinions of the group.

Minutes or meeting notes will be recorded for all EECAG meetings. These notes will contain a record of EECAG feedback and any decisions made during the meeting, and will be circulated to attending members to review for omissions and errors prior to being considered final. A discussion of the EECAG's activities, feedback and decisions will be included in the EEC Annual Report, submitted to the BCUC in the first quarter of the year following the reporting year.

Comments and opinions expressed during meetings will not be attributed to individuals if and when reported in FEU's EEC Annual Reports or other regulatory filings. It should be noted, however, that the BCUC, as part of its regulation of FEU under the BC Utilities Commission Act, may require FEU to file any documents created as a result of or distributed as part of EECAG activity.

8 DECISION MAKING

The EECAG is intended to function as an advisory group. The group's diversity and varying perspectives are a valued part of FEU's decision making process, and therefore FEU will seek robust discussion from the EECAG and will endeavor to report on those discussions with transparency, accuracy and completeness.

On decision making issues where FEU is seeking the opinion of the EECAG, the EECAG recognizes that FEU is ultimately responsible for making decisions concerning its EEC activities and seeking approval from the BCUC where necessary. As such, FEU may seek opinions from the EECAG for certain matters in support of its decisions and applications or submissions to the BCUC. FEU commits to document the results of such feedback, including opinions that may be in disagreement, and fully report on such feedback in any related submissions to the BCUC. The Independent Facilitator shall play an advisory role in planning the methods by which FEU seeks consensus and in the completeness of reporting the results.

The purpose of obtaining such opinions is for FEU to:

- Gain an understanding of the preference of the EECAG on a decision or recommendation
- Document such preference
- Consider such preference in determining a course of action
- Be able to report such preference in an application or submission to the BCUC related to the matter at hand

9 RESPONSIBILITIES

MEMBERS

- Provide feedback and direction
- Raise issues and suggest solutions
- Bring forth ideas beneficial to all
- Keep topics within PURPOSE & OBJECTIVES and SCOPE
- Attend meetings/workshops as confirmed or send an alternate (on an occasional basis only)
- Participate in recommendations or decision making activities (see DECISION MAKING)
- Participate in periodic meeting/workshop evaluations and surveys to help improve the effectiveness of EECAG activities
- Carry pertinent information from EECAG activities back to the organizations/interest groups they represent to disseminate and consider as appropriate
- Review FEU reports on EECAG activities and feedback to ensure accurate recording of member comments

INDEPENDENT FACILITATOR

- Act as an advisor on EECAG activity plans, agendas, meetings and other activities as needed
- Act as an advisor on EECAG membership (selection process, review process, representation)
- Act as a third-party facilitator at EECAG meetings

- Act as an advisor on the reporting of EECAG activities and feedback

FEU

- Host meetings
- Appoint EECAG members
- Appoint Independent Facilitator
- Work with the Independent Facilitator on EECAG plans, agendas, meetings, membership and other activities as needed
- Provide pre-reading materials for upcoming meetings or workshops approximately 2 weeks in advance
- Record and consider suggestions and stakeholder input Draft and distribute meeting minutes
- Follow up with stakeholders post-meeting, if necessary
- Include detailed summaries of EECAG activities in EEC Annual Reports

10 GUESTS

Guest speakers will occasionally be invited to discuss their fields of expertise as it pertains to the industry. Such speakers may be identified by either FEU or EECAG members.

FEU or EECAG members may wish to invite guest attendees from time to time. Where EECAG members wish to invite guests (not including alternates), the EECAG member must seek approval from FEU prior to extending such invitation. In considering such requests, FEU will take into account such things as the meeting purpose, meeting effectiveness, meeting facilities and the reasons why the EECAG member wants to extend the invitation. Email communication is the preferred method of seeking such approval.

11 EXPENSES

FEU will entertain reasonable expenses up to a limit of CA$500 (e.g. travel and lodging) for EECAG Members from outside of the Lower Mainland to attend workshops. Anything above CA$500 will be reviewed on a case by case and exception basis. EECAG members will be reimbursed for expenses incurred to attend a meeting or workshop once valid receipts and invoices are submitted to FEU. Confirmation of attendance is required (e.g. registration on the sign in sheet.)

12 ATTENDANCE

Attendance is not mandatory, but is strongly encouraged and highly valued. If an EECAG member cannot attend a meeting, an appropriate alternate from the same organization may attend as an occasional substitute. The attendance of such alternates must be confirmed with FEU in advance of the meeting. A sign-in sheet will be available at all meetings to confirm the attendance and participation of stakeholders.

13 EVALUATIONS

Evaluation documents will be circulated periodically to collect valuable and necessary feedback. This information will be used to strengthen and enhance future workshops and correspondence. Feedback may also be submitted at any time to the contact below. Surveys may also be conducted from time to time to help evaluate the effectiveness of EECAG activities.

14 CONTACT (FEU Lead EECAG Representative)

All communications between FEU and EECAG members should be directed through the FEU Lead EECAG Representative identified below.

Ken Ross	Integrated Resource Planning Manager	604-576-7343	ken.ross@fortisbc.com

The Lead Representative may change from time to time without requiring an update to these ToR. EECAG members will be notified of such changes.

15 MEMBER CONFIRMATION

I, the undersigned, agree to participate as a member of FEU's EECAG pursuant to the Terms of Reference set out above.

Signature ________________________________ Date _________________
Print name:
Organization:
Phone:
Email:

Attachment 217.2

Understanding Cost-Effectiveness of Energy Efficiency Programs:

Best Practices, Technical Methods, and Emerging Issues for Policy-Makers

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2008

About This Document

This paper, *Understanding Cost-Effectiveness of Energy Efficiency Programs*, is provided to assist utility regulators, gas and electric utilities, and others in meeting the 10 implementation goals of the National Action Plan for Energy Efficiency's Vision to achieve all cost-effective energy efficiency by 2025.

This paper reviews the issues and approaches involved in considering and adopting cost-effectiveness tests for energy efficiency, including discussing each perspective represented by the five standard cost-effectiveness tests and clarifying key terms.

The intended audience for the paper is any stakeholder interested in learning more about how to evaluate energy efficiency through the use of cost-effectiveness tests. All stakeholders, including public utility commissions, city councils, and utilities, can use this paper to understand the key issues and terminology, as well as the various perspectives each cost-effectiveness test provides, and how the cost-effectiveness tests can be implemented to capture additional energy efficiency.

Understanding Cost-Effectiveness of Energy Efficiency Programs:

Best Practices, Technical Methods, and Emerging Issues for Policy-Makers

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2008

The Leadership Group of the National Action Plan for Energy Efficiency is committed to taking action to increase investment in cost-effective energy efficiency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers* was developed under the guidance of and with input from the Leadership Group. The document does not necessarily represent a consensus view and does not represent an endorsement by the organizations of Leadership Group members.

Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers is a product of the National Action Plan for Energy Efficiency and does not reflect the views, policies, or otherwise of the federal government. The role of the U.S. Department of Energy and U.S. Environmental Protection Agency is limited to facilitation of the Action Plan.

If this document is referenced, it should be cited as:

National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*. Energy and Environmental Economics, Inc. and Regulatory Assistance Project. <www.epa.gov/eeactionplan>

For More Information

Regarding *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*, please contact:

Katrina Pielli
U.S. Environmental Protection Agency
Office of Air and Radiation
Climate Protection Partnerships Division
Tel: (202) 343-9610
E-mail: pielli.katrina@epa.gov

Regarding the National Action Plan for Energy Efficiency, please contact:

Stacy Angel
U.S. Environmental Protection Agency
Office of Air and Radiation
Climate Protection Partnerships Division
Tel: (202) 343-9606
E-mail: angel.stacy@epa.gov

Larry Mansueti
U.S. Department of Energy
Office of Electricity Delivery and Energy Reliability
Tel: (202) 586-2588
E-mail: lawrence.mansueti@hq.doe.gov

or visit www.epa.gov/eeactionplan

Table of Contents

List of Figures

List of Tables

List of Abbreviations and Acronyms

AEO	Annual Energy Outlook
Btu	British thermal unit
CCGT	combined cycle gas turbine
CDM	conservation and demand management
CEC	California Energy Commission
CFL	compact fluorescent light bulb
CO_2	carbon dioxide
DCR	debt-coverage ratio
DOE	U.S. Department of Energy
DR	demand response
DSM	demand-side management
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
HP	horsepower
HVAC	heating, ventilation, and air conditioning
ICAP	installed capacity
IOU	investor-owned utility
IRP	integrated resource planning
kW	kilowatt
kWh	kilowatt-hour
LNG	liquefied natural gas
LSE	load serving entity
MMBtu	million Btu
MW	megawatt
MWh	megawatt-hour
NEBs	non-energy benefits
NO_x	nitrogen oxides
NPV	net present value
NTG	net-to-gross ratio
NWPCC	Northwest Power and Conservation Council
NYSERDA	New York State Energy Research and Development Authority
PACT	program administrator cost test (same as UCT)
PCT	participant cost test
PSE	Puget Sound Energy
RIM	ratepayer impact measure test
ROE	return on equity
RPS	renewable portfolio standard
SCE	Southern California Edison
SCT	societal cost test
SEER	Seasonal Energy Efficiency Ratio
SO_x	sulfur oxides
T&D	transmission and distribution
TOU	time of use
TRC	total resource cost test
TWh	terawatt-hour
UCAP	unforced capacity
UCT	utility cost test (same as PACT)
VOC	volatile organic compound
WACC	weighted average cost of capital

Acknowledgements

This technical issue paper, *Understanding Cost-Effectiveness of Energy Efficiency Programs,* is a key product of the Year Three Work Plan for the National Action Plan for Energy Efficiency. This work plan was developed based on Action Plan Leadership Group discussions and feedback expressed during and in response to the January 7, 2008, Leadership Group Meeting and the February 2008 Initial Draft Work Plan. A full list of Leadership Group members is provided in Appendix A.

With direction and comment by the Action Plan Leadership Group, the paper's development was led by Snuller Price, Energy and Environmental Economics, Inc., under contract to the U.S. Environmental Protection Agency (EPA). Additional preparation was performed by Eric Cutter and Rebecca Ghanadan of Energy and Environmental Economics, Inc.

Rich Sedano and Brenda Hausauer of the Regulatory Assistance Project supplied information on the use of cost-effectiveness tests by states and provided their expertise during the review and editing of the paper. Alison Silverstein also provided expertise during the review and editing of the paper.

EPA and the U.S. Department of Energy (DOE) facilitate the National Action Plan for Energy Efficiency. Key staff include Larry Mansueti (DOE Office of Electricity Delivery and Energy Reliability), Dan Beckley (DOE Office of Energy Efficiency and Renewable Energy), and Kathleen Hogan, Katrina Pielli, and Stacy Angel (EPA Climate Protection Partnership Division).

Eastern Research Group, Inc., provided copyediting, graphics, and production services.

Executive Summary

This paper, Understanding Cost-Effectiveness of Energy Efficiency Programs, reviews the issues and approaches involved in considering and adopting cost-effectiveness tests for energy efficiency, including discussing each perspective represented by the five standard cost-effectiveness tests and clarifying key terms. This paper is provided to assist organizations in meeting the 10 implementation goals of the National Action Plan for Energy Efficiency's Vision to achieve all cost-effective energy efficiency by 2025.

Improving energy efficiency in our homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Despite these benefits and the success of energy efficiency programs in some regions of the country, energy efficiency remains critically underutilized in the nation's energy portfolio. It is time to take advantage of more than two decades of experience with successful energy efficiency programs, broaden and expand these efforts, and capture the savings that energy efficiency offers. Understanding energy efficiency cost-effectiveness tests and the various stakeholder perspectives each test represents is key to establishing the policy framework to capture these benefits.

This paper has been developed to help parties pursue the key policy recommendations and implementation goals of the National Action Plan for Energy Efficiency. The Action Plan was released in July 2006 as a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new level. This paper directly supports the National Action Plan's Vision for 2025 implementation goal three, which encourages state agencies along with key stakeholders to establish cost-effectiveness tests for energy efficiency. This goal highlights the policy step to establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.

Evaluating the cost-effectiveness of energy efficiency is essential to identifying how much of our country's potential for energy efficiency resources will be captured. Based on studies, energy efficiency resources may be able to meet 50 percent or more of the expected load growth by 2025 (National Action Plan for Energy Efficiency, 2008). Defining cost-effectiveness helps energy efficiency compete with the broad range of other resource options in order for energy efficiency to get the attention and funding necessary to succeed.

In its simplest form, energy efficiency cost-effectiveness is measured by comparing the benefits of an investment with the costs. Five key cost-effectiveness tests have, with minor updates, been used for over 20 years as the principal approaches for energy efficiency program evaluation. These five cost-effectiveness tests are the participant cost test (PCT), the utility/program administrator cost test (PACT), the ratepayer impact measure test (RIM), the total resource cost test (TRC), and the societal cost test (SCT).

The key points from this paper include:

- There is no single best test for evaluating the cost-effectiveness of energy efficiency.

- Each of the cost-effectiveness tests provides different information about the impacts of energy efficiency programs from distinct vantage points in the energy system. Together, multiple tests provide a comprehensive approach.

- Jurisdictions seeking to increase efficiency implementation may choose to emphasize the PACT, which compares energy efficiency as a utility investment on a par with other resources.

- The most common primary measurement of energy efficiency cost-effectiveness is the TRC, followed closely by the SCT. A positive TRC result indicates that the program will produce a net reduction in energy costs in the utility service territory over the lifetime of the program. The distributional tests (PCT, PACT, and RIM) are then used to indicate how different stakeholders are affected. Historically, reliance on the RIM test has limited energy efficiency investment, as it is the most restrictive of the five cost-effectiveness tests.

There are a number of choices in developing the costs and benefits of energy efficiency that can significantly affect the cost-effectiveness results. Several major choices available to utilities, analysts, and policy-makers are described below.

- **Where in the process to apply the cost-effectiveness tests:** The choice of where to apply each cost-effectiveness test has a significant impact on the ultimate set of measures offered to customers. In general, there are three places to evaluate the cost-effectiveness test: at the "measure" level, the "program" level, and the "portfolio" level. Applying cost-effectiveness tests at the program or portfolio levels allows some non-cost-effective measures or programs to be offered as long as their shortfall is more than offset by cost-effective measures and programs.

- **Which benefits to include:** There are two main categories of avoided costs: energy-related and capacity-related. Energy-related avoided costs refer to market prices of energy, fuel costs, natural gas commodity prices, and other variable costs. Capacity-related avoided costs refer to infrastructure investments such as power plants, transmission and distribution lines, and pipelines. From an environmental point of view, saving energy reduces air emissions, including greenhouse gases (GHGs). Within each of these categories, policy-makers must decide which specific benefits are sufficiently known and quantifiable to be included in the cost-effectiveness evaluation.

- **Net present value and discount rates:** A significant driver of overall cost-effectiveness of energy efficiency is the discount rate assumption used to calculate the net present value (NPV) of the annual costs and benefits. Since costs typically occur upfront and savings occur over time, the lower the discount rate the more likely the cost-effectiveness result is to be positive. As each cost-effectiveness test portrays a specific stakeholder's view, each cost-effectiveness test should use the discount rate associated with its perspective. For a household, the consumer lending rate is used, since this is the debt cost that a private individual would pay to finance an energy efficiency investment. For a business firm, the discount rate is the firm's weighted average cost of capital, typically in the 10 to 12 percent range. However, commercial and industrial customers often demand payback periods of two years or less, implying a discount rate well in excess of 20 percent. The PACT, RIM, and TRC should reflect the utility weighted average cost of capital. The social discount rate (typically the lowest rate) should be used for the SCT to reflect the benefit to society over the long term.

- **Net-to-gross ratio (NTG):** The NTG can be a significant driver in the results of TRC, PACT, RIM, and SCT. The NTG adjusts the impacts of the programs so that they only reflect those energy efficiency gains that are the result of the energy efficiency program. Therefore, the NTG deducts energy savings that would have been achieved without the efficiency program (e.g., “free-riders”) and increases savings for any “spillover” effect that occurs as an indirect result of the program. Since the NTG attempts to measure what customers would have done in the absence of the energy efficiency program, it can be difficult to determine precisely.

- **Non-energy benefits (NEBs):** Energy efficiency measures often have additional benefits (and costs) beyond energy savings, such as improved comfort, productivity, health, convenience and aesthetics. However, these benefits can be difficult to quantify. Some jurisdictions choose to include NEBs and costs in some of the cost-effectiveness tests, often focusing on specific issues emphasized in state policy.

- **GHG emissions:** There is increasing interest in valuing the energy efficiency’s effect on reducing GHG emissions in the cost-effectiveness tests. The first step is to determine the quantity of avoided carbon dioxide (CO_2) emissions from the efficiency program. Once the amount of CO_2 reductions has been determined, its economic value can be calculated and added to the net benefits of the energy efficiency measures used to achieve the reductions. Currently, some jurisdictions use an explicit monetary CO_2 value in cost-benefit calculations and some do not.

- **Renewable portfolio standards (RPS):** The interdependence between energy efficiency and RPS goals is an emerging issue in energy efficiency. Unlike supply-side investments, energy efficiency, by reducing load, can reduce the amount of renewable energy that must be procured pursuant to RPS targets. This reduces RPS compliance cost, which is a benefit that should be considered in energy efficiency cost-effectiveness evaluation.

1: Introduction

Improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Mining this efficiency could help us meet on the order of 50 percent or more of the expected growth in U.S. consumption of electricity and natural gas in the coming decades, yielding many billions of dollars in saved energy bills and avoiding significant emissions of greenhouse gases and other air pollutants.[1]

Recognizing this large opportunity, more than 60 leading organizations representing diverse stakeholders from across the country joined together to develop the National Action Plan for Energy Efficiency. The Action Plan identifies many of the key barriers contributing to underinvestment in energy efficiency; outlines five policy recommendations for achieving all cost-effective energy efficiency; and offers a wealth of resources and tools for parties to advance these recommendations, including a Vision for 2025. As of November 2008, over 120 organizations have endorsed the Action Plan recommendations and made public commitments to implement them in their areas. Establishing cost-effectiveness tests for energy efficiency investments is key to making the Action Plan a reality.

1.1 Background on Cost-effectiveness Tests

The question of how to define the cost-effectiveness of energy efficiency investments is a critical issue to address when advancing energy efficiency as a key resource in meeting future energy needs. How cost-effectiveness is defined substantially affects how much of our nation's efficiency potential will be accessed and whether consumers will benefit from the lower energy costs and environmental impacts that would result. The decisions on how to define cost-effectiveness or which tests to use are largely made by state utility commissions and their utilities, and with critical input from consumers and other stakeholders. This paper is provided to help facilitate these discussions.

Cost-effectiveness in its simplest form is a measure of whether an investment's benefits exceed its costs. Key differences among the cost-effectiveness tests that are currently used include the following:

- **The stakeholder perspective of the test.** Is it from the perspective of an energy efficiency program participant, the organization offering the energy efficiency program, a non-participating ratepayer, or society in general? Each of these perspectives represents a valid viewpoint and has a role in assessing energy efficiency programs.

- **The key elements included in the costs and the benefits.** Do they reflect avoided energy use, incentives for energy efficiency, avoided need for new generation and new transmission and distribution, and avoided environmental impacts?

- **The baseline against which the cost and benefits are measured.** What costs and benefits would have been realized absent investment in energy efficiency?

The five cost-effectiveness tests commonly used across the country are listed below:

- Participant cost test (PCT).
- Program administrator cost test (PACT).[2]
- Ratepayer impact measure test (RIM).
- Total resource cost test (TRC).
- Societal cost test (SCT).

These cost-effectiveness tests are used differently in different states. Some states require all of the tests, some require no specific tests, and others designate a primary test. Table 1-1 provides a quick overview of which tests are used in which states. Chapter 5 presents more information and guidelines on the use of the cost-effectiveness tests by the states.

Table 1-1. Cost-Effectiveness Tests in Use by Different States as Primary or Secondary Consideration

PCT	PACT	RIM	TRC	SCT
AR, FL, GA, HI, IA, IN, MN, VA	AT, CA, **CT**, HI, IA, IN, MN, NO, NV, OR, **UT**, VA, **TX**	AR, DC, **FL**, GA, HI, IA, IN, KS, MN, NH, VA	AR, **CA**, CO, CT, DE, FL, GA, HI, IL, IN, KS, **MA**, MN, **MO**, MT, **NH**, **NM**, NY, UT, VA	**AZ**, CO, GA, HI, IA, IN, MW, **ME**, **MN**, MT, NV, OR, VA, **VT**, **WI**

Source: Regulatory Assistance Project (RAP) analysis.

Note: Boldface indicates the primary cost-effectiveness test used by each state.

1.2 About the Paper

This paper examines the five standard cost-effectiveness tests that are regularly used to assess the cost-effectiveness of energy efficiency, the perspectives each test represents, and how states are currently using the tests. It also discusses how the tests can be used to provide a more comprehensive picture of the cost-effectiveness of energy efficiency as a resource. Use of a single cost-effectiveness test as a primary cost-effectiveness test may lead to an efficiency portfolio that does not balance the benefits and costs between stakeholder perspectives. Overall, using all five cost-effectiveness tests provides a more comprehensive picture than using any one test alone.

Paper Objective

After reading this paper, the reader should be able to understand each the perspective represented by each of the five standard cost tests, understand that all five tests provide a more comprehensive picture than any one test alone, have clarity around key terms and definitions, and use this information to shape how the cost-effectiveness of energy efficiency programs is treated.

This paper was prepared in response to a need identified by the Action Plan Leadership Group (see Appendix A) for a practical discussion of the key considerations and technical terms involved in defining cost-effectiveness and establishing which cost-effectiveness tests to use in developing an energy efficiency program portfolio. The Leadership Group offers this reference to program designers and policy-makers who are involved in adopting and implementing cost-effectiveness tests for evaluating efficiency investments.

This paper supports the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change* (National Action Plan for Energy Efficiency, 2008). This Vision establishes a long-term aspirational goal to achieve all cost-effective energy efficiency by 2025 and outlines 10 goals for implementing the Leadership Group's recommendations (see Figure 1-1). This paper directly supports the Vision's third implementation goal, which encourages states and key stakeholders to establish cost-effectiveness tests for energy efficiency. This goal encourages applicable state agencies, along with key stakeholders, to establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.

Figure 1-1. Ten Implementation Goals of the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change*

Goal One:	Establishing Cost-Effective Energy Efficiency as a High-Priority
Goal Two:	Developing Processes to Align Utility and Other Program Administrator Incentives Such That Efficiency and Supply Resources Are on a Level Playing Field
Goal Three:	Establishing Cost-Effectiveness Tests
Goal Four:	Establishing Evaluation, Measurement, and Verification Mechanisms
Goal Five:	Establishing Effective Energy Efficiency Delivery Mechanisms
Goal Six:	Developing State Policies to Ensure Robust Energy Efficiency Practices
Goal Seven:	Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency
Goal Eight:	Establishing State of the Art Billing Systems
Goal Nine:	Implementing State of the Art Efficiency Information Sharing and Delivery Systems
Goal Ten:	Implementing Advanced Technologies

1.3 Structure of the Paper

This paper walks the reader through the basics of cost-effectiveness tests and the perspectives they represent, issues in determining the costs and benefits to include in the cost-effectiveness tests, emerging issues, how states are currently using cost-effectiveness tests, and guidelines for policy-makers.

The key chapters of the paper are the following:

- **Chapter 2.** This chapter discusses the five standard cost-effectiveness tests and their application in four utility best practice programs.

- **Chapter 3.** This chapter briefly describes the interpretation of each test and presents a calculation of each cost-effectiveness test using an example residential program from Southern California Edison.

- **Chapter 4.** This chapter presents the key factors and issues in the determination of an energy efficiency program's cost-effectiveness. It also discusses key emerging issues that are shaping energy efficiency programs, including the impact greenhouse gas (GHG) reduction targets and renewable portfolio standards (RPS) may have on energy efficiency programs.

- **Chapter 5.** This chapter gives guidelines and examples for policy-makers to consider when choosing which cost-effectiveness test(s) to emphasize, and summarizes of the use of the cost-effectiveness tests in each state.

- **Chapter 6.** This chapter describes the calculation of each cost-effectiveness test in detail, as well as the key considerations when reviewing and using cost-effectiveness tests and the pros and cons of each test in relation to increased efficiency investment.

- **Appendix C.** This chapter gives further detail on the four example programs included in Chapter 2. It also describes how the cost-effectiveness test results were calculated for each program.

1.4 Development of the Paper

Understanding Cost-Effectiveness of Energy Efficiency Programs is a product of the Year Three Work Plan for the National Action Plan for Energy Efficiency. With direction and comment by the Action Plan Leadership Group (see Appendix A for a list of group members), the paper's development was led by Snuller Price, Eric Cutter, and Rebecca Ghanadan of Energy and Environmental Economics, Inc., under contract to the U.S. Environmental Protection Agency and the U.S. Department of Energy. Chapter 5 was authored by Rich Sedano and Brenda Hausauer of the Regulatory Assistance Project, under contract to the U.S. Department of Energy.

1.5 Notes

1 See the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change* (National Action Plan for Energy Efficiency, 2008).

2 The program administrator cost test, or PACT, was originally named the utility cost test (UCT). As program management has expanded to government agencies, nonprofit groups, and other parties, the term "program administrator cost test" has come into use, but the computations are the same. This document refers to the UCT/PACT as the "PACT" for simplicity. See Section 6.2 for more information on the test.

2: Getting Started: Overview of the Cost-Effectiveness Tests

This chapter provides a brief overview of the cost-effectiveness tests used to evaluate energy efficiency measures and programs. All the cost-effectiveness tests use the same fundamental approach in comparing costs and benefits. However, each test is designed to address different questions regarding the cost-effectiveness of energy efficiency programs.

2.1 Structure of the Cost-Effectiveness Tests

Each of the tests provides a different kind of information about the impacts of energy efficiency programs from different vantage points in the energy system. On its own, each test provides a single stakeholder perspective. Together, multiple tests provide a comprehensive approach for asking: Is the program effective overall? Is it balanced? Are some costs or incentives too high or too low? What is the effect on rates? What adjustments are needed to improve the alignment? Each test contributes one of the aspects necessary to understanding these questions and answering them.

The basic structure of each cost-effectiveness test involves a calculation of the total benefits and the total costs in dollar terms from a certain vantage point to determine whether or not the overall benefits exceed the costs. A test is positive if the benefit-to-cost ratio is greater than one, and negative if it is less than one. Results are reported either in net present value (NPV) dollars (method by difference) or as a ratio (i.e., benefits/costs). Table 2-1 outlines the basic approach underlying cost-effectiveness tests.

Table 2-1. Basic Approach for Calculating and Representing Cost-Effectiveness Tests

Net Benefits (Difference)	Net Benefits_a (dollars)	=	$\text{NPV} \sum \text{benefits}_a \text{ (dollars)} - \text{NPV} \sum \text{costs}_a \text{ (dollars)}$
Benefit-Cost Ratio	$\text{Benefit-Cost Ratio}_a$	=	$\dfrac{\text{NPV} \sum \text{benefits}_a \text{ (dollars)}}{\text{NPV} \sum \text{costs}_a \text{ (dollars)}}$

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Note: "NPV" refers to the net present value of benefits and costs. See Section 4.6.

> Cost-effectiveness test results compare relative benefits and costs from different perspectives. A benefit-cost ratio above 1 means the program has positive net benefits. A benefit-cost ratio below 1 means the costs exceed the benefits. A first step in analyzing programs is to see which cost-effectiveness tests are produce results above or below 1.

2.2 The Five Cost-Effectiveness Tests and Their Origins

Currently, five key tests are used to compare the costs and benefits of energy efficiency and demand response programs. These tests all originated in California. In 1974, the Warren Alquist Act established the California Energy Commission (CEC) and specified cost-effectiveness as a leading resource planning principle. In 1983, California's *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* manual developed five cost-effectiveness tests for evaluating energy efficiency programs. These approaches, with minor updates, continue to be used today and are the principal approaches used for evaluating energy efficiency programs across the United States.[1]

Table 2-2 summarizes the five tests in terms of the questions they help answer and the key elements of the comparison.

Table 2-2. The Five Principal Cost-Effectiveness Tests Used in Energy Efficiency

Test	Acronym	Key Question Answered	Summary Approach
Participant cost test	PCT	Will the participants benefit over the measure life?	Comparison of costs and benefits of the customer installing the measure
Program administrator cost test	PACT	Will utility bills increase?	Comparison of program administrator costs to supply-side resource costs
Ratepayer impact measure	RIM	Will utility rates increase?	Comparison of administrator costs and utility bill reductions to supply-side resource costs
Total resource cost test	TRC	Will the total costs of energy in the utility service territory decrease?	Comparison of program administrator and customer costs to utility resource savings
Societal cost test	SCT	Is the utility, state, or nation better off as a whole?	Comparison of society's costs of energy efficiency to resource savings and non-cash costs and benefits

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

2.3 Cost-Effectiveness Test Results in Best Practice Programs

Illustrating cost-effectiveness test calculations, Table 2-3 shows benefit-cost ratio results from four successful energy efficiency programs from across the country.[2] The Southern California Edison (SCE) Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances. Avista's results are for its Regular Income Portfolio, which includes a variety of programs targeted to residential users. Puget Sound Energy's Commercial/Industrial Retrofit Program encourages commercial customers to install cost- and energy-efficient equipment, adopt energy-efficient designs, and use energy-efficient operations at their facilities. Finally, the National Grid's MassSAVE residential program provides residential in-home audits and incentives for comprehensive whole-house improvements.

All the programs presented have been determined to be cost-effective by the relevant utilities[3] and regulators. Nevertheless, the results of the five cost-effectiveness tests vary significantly for each program. Furthermore, the result of each cost-effectiveness test across the four programs is also quite different. (Puget Sound Energy is the only utility for which all five cost-effectiveness tests are positive.) The test results show a range of values that reflect the program designs and the individual choices made by the program administrators and policy-makers for their evaluation. As later chapters discuss, both the individual tests *and* the relationships between test results offer useful information for assessing programs.

Table 2-3. Summary of Cost-effectiveness Test Results for Four Energy Efficiency Programs

Test	Southern California Edison Residential Energy Efficiency Incentive Program	Avista Regular Income Portfolio	Puget Sound Energy Commercial/ Industrial Retrofit Program	National Grid MassSAVE Residential
	Benefit-Cost Ratio			
PCT	7.14	3.47	1.72	8.81
PACT	9.91	4.18	4.19	2.64
RIM	0.63	0.85	1.15	0.54
TRC	4.21	2.26	1.90	1.73
SCT	4.21	2.26	1.90	1.75

Source: E3 analysis; see Appendix C.

Note: The calculation of each cost-effectiveness test varies slightly by jurisdiction. See Appendix C for more details.

The choice of cost-effectiveness test depends on the policy goals and circumstances of a given program and state. Multiple tests yield a more comprehensive assessment than any test on its own.

2.4 Notes

1 The California standard practice manual was first developed in February 1983. It was later revised and updated in 1987–88 and 2001; a Correction Memo was issued in 2007. The 2001 California SPM and 2007 Correction Memo can be found at <http://www.cpuc.ca.gov/PUC/energy/electric/Energy+Efficiency/EM+and+V/>.

2 The cost-effectiveness test results of each program are described further in Appendix C.

3 "Utility" refers to any organization that delivers electric and gas utility services to end users, including investor-owned, cooperatively owned, and publicly owned utilities.

3: Cost-Effectiveness Test Review—Interpreting the Results

This chapter discusses the benefit and cost components included in each cost-effectiveness test, and profiles how a residential lighting and appliance incentive program fares under each test. It also provides an overview of important considerations when using cost-effectiveness tests.

Overall, the results of all five cost-effectiveness tests provide a more comprehensive picture than the use of any one test alone. The TRC and SCT cost tests help to answer whether energy efficiency is cost-effective overall. The PCT, PACT, and RIM help to answer whether the selection of measures and design of the program is balanced from participant, utility, and non-participant perspectives respectively. Looking at the cost-effectiveness tests together helps to characterize the attributes of a program or measure to enable decision making, to determine whether some measures or programs are too costly, whether some costs or incentives are too high or too low, and what adjustments need to be made to improve distribution of costs and benefits among stakeholders. The scope of the benefit and cost components included in each test is summarized in Table 3-1 and Table 3-2.

The broad categories of costs and benefits included in each cost-effectiveness test are consistent across all regions and applications. However, the specific components included in each test may vary across different regions, market structures, and utility types. Transmission and distribution investment may be considered deferrable through energy efficiency in some areas and not in others. Likewise, the TRC and SCT may consider just natural gas or electricity resource savings in some cases, but also include co-benefits of other savings streams (such as water and fuel oil) in others. Considerations regarding the application of each cost-effectiveness test and which cost and benefit components to include are the subject of Chapter 5.

3.1 Example: Southern California Edison Residential Energy Efficiency Program

The Southern California Edison (SCE) Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances (not including HVAC). It is part of a statewide mass market efficiency program that coordinates marketing and outreach efforts. This section summarizes how to calculate cost-effectiveness for each cost-effectiveness test using the SCE Residential Energy Efficiency Incentive Program as an example. Calculations for three additional programs from other utilities are evaluated in Appendix C.

Table 3-1. Summary of Benefits and Costs Included in Each Cost-Effectiveness Test

Test	Benefits	Costs
PCT	*Benefits and costs from the perspective of the customer installing the measure*	
	▪ Incentive payments ▪ Bill savings ▪ Applicable tax credits or incentives	▪ Incremental equipment costs ▪ Incremental installation costs
PACT	*Perspective of utility, government agency, or third party implementing the program*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program overhead costs ▪ Utility/program administrator incentive costs ▪ Utility/program administrator installation costs
RIM	*Impact of efficiency measure on non-participating ratepayers overall*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program overhead costs ▪ Utility/program administrator incentive costs ▪ Utility/program administrator installation costs ▪ Lost revenue due to reduced energy bills
TRC	*Benefits and costs from the perspective of all utility customers (participants and non-participants) in the utility service territory*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (i.e., gas and water if utility is electric) ▪ Monetized environmental and non-energy benefits (see Section 4.9) ▪ Applicable tax credits (see Section 6.4)	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or utility)
SCT	*Benefits and costs to all in the utility service territory, state, or nation as a whole*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (i.e., gas and water if utility is electric) ▪ Non-monetized benefits (and costs) such as cleaner air or health impacts	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Table 3-2. Summary of Benefits and Costs Included in Each Cost-Effectiveness Test

Component	PCT	PACT	RIM	TRC	SCT
Energy- and capacity-related avoided costs		Benefit	Benefit	Benefit	Benefit
Additional resource savings				Benefit	Benefit
Non-monetized benefits					Benefit
Incremental equipment and installation costs	Cost			Cost	
Program overhead costs		Cost	Cost	Cost	Cost
Incentive payments	Benefit	Cost	Cost		
Bill savings	Benefit		Cost		

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Note: Incentive payments include any equipment and installation costs paid by the program administrator.

3.1.1 Overview of the Program

The SCE Residential Energy Efficiency Incentive Program resulted in costs of:

- $3.5 million in administration and marketing for SCE.
- $15.5 million in customer incentives, direct installation, and upstream payments combined for SCE.
- $41.1 million in measure installation costs for customers (before incentives).

The reduced energy consumption achieved as a result of the program resulted in:

- $188 million in avoided cost savings to the utility.
- $278 million in bill savings to the customers (and reduced revenue to SCE).
- Reduced nitrogen oxides (NO_x), PM_{10},[1] and carbon dioxide (CO_2) emissions.

The costs and savings are presented on a “net” basis, after the application of the net-to-gross ratio (NTG). The determination of the NTG is described in Section 4.7. The benefits and costs of the SCE program are presented in Table 3-3 and Table 3-4. Together, these two tables provide the key parameters for employing individual cost-effectiveness tests, as well as the calculations leading to each test are discussed in turn.

Table 3-3. SCE Residential Energy Efficiency Incentive Program Benefits

Net Benefit Inputs		
Resource savings	**Units**	**$**
Energy (MWh)	2,795,290	$ 187,904,906
Peak demand (kW)	55,067	—
Total resource savings		**$ 187,904,906**
Participant bill savings		**$ 278,187,587**
Emission savings	**Tons**	
NO_x	421,633	
PM_{10}	203,065	
CO_2	1,576,374	

Source: E3 analysis; see Appendix C.

Table 3-4. SCE Residential Energy Efficiency Incentive Program Costs

Cost Inputs	
Program overhead	
Program administration	$ 898,548
Marketing and outreach	$ 559,503
Rebate processing	$ 1,044,539
Other	$ 992,029
Total program administration	**$ 3,494,619**
Program incentives	
Rebates and incentives	$ 1,269,393
Direct installation costs	$ 564,027
Upstream payments	$ 13,624,460
Total incentives	**$ 15,457,880**
Total program costs	**$ 18,952,499**
Net measure equipment and installation	**$ 41,102,993**

Source: E3 analysis; see Appendix C.

3.1.2 Cost-Effectiveness Test Results Overview

The results of each of the five cost-effectiveness tests for 2006 (based on the information in the fourth quarter 2006 SCE filing) are presented in Table 3-5[2] A first level assessment shows that the SCE program is very cost-effective for the participant (PCT), the utility (PACT), and the region as a whole (TRC). The program will reduce average energy bills, and a RIM below 1.0 suggests that the program will increase customer rates. Greater detail on the application of each of these cost-effectiveness tests is provided below.

Table 3-5. Summary of Cost-Effectiveness Test Results ($Million)

Test	Cost	Benefits	Ratio	Result
PCT	$41	$294	7.14	Bill savings are more than seven times greater than customer costs.
PACT	$19	$188	9.91	The value of saved energy is nearly 10 times greater than the program cost.
RIM	$297	$188	0.63	The reduced revenue and program cost is greater than utility savings.
TRC	$45	$188	4.21	Overall benefits are four times greater than the total costs.
SCT	$45	$188	4.21	Same as the TRC, as no additional benefits are currently included in the SCT in California.

Source: E3 analysis; see Appendix C.

3.1.3 Calculating the PCT

The PCT assesses the costs and benefits from the perspective of the customer installing the measure. Overall, customers received $294 million in benefits (derived from utility program incentives and bill savings from reduced energy use). The incremental costs to customers were $41 million. This yields an overall net benefit of $252 million and a benefit-cost ratio of 7.14. The PCT shows that bill savings are seven times customer costs—a cost-effective program for the participant. PCT calculation terms from the SCE program data are presented in Table 3-6.

Table 3-6. Participant Cost Test for SCE Residential Energy Efficiency Program

PCT Calculations		
	Benefits	**Costs**
Program overhead		
Program incentives	$ 15,457,880	
Measure costs		$ 41,102,993
Energy savings		
Bill savings	$ 278,187,587	
Monetized emissions		
Non-energy benefits		
Total	**$ 293,645,466**	**$ 41,102,993**
Net benefit	**$252,542,473**	
Benefit-cost ratio	**7.1**	

Source: E3 analysis; see Appendix C.

3.1.4 Calculating the PACT

The PACT calculates the costs and benefits of the program from the perspective of SCE as the utility implementing the program. SCE's avoided costs of energy are $188 million (energy savings). Overhead and incentive costs to SCE are $19 million. These figures yield an overall net benefit of $169 million and a benefit-to-cost ratio of 9.91. The PACT result shows that the value of saved energy is nearly 10 times greater than the program cost: high cost-effectiveness from the perspective of the utility's administration of the program. Table 3-7 shows the breakdown of costs and benefits yielding the positive PACT result.

Table 3-7. Program Administrator Cost Test for SCE Residential Efficiency Program

PACT Calculations		
	Benefits	**Costs**
Program overhead		$ 3,494,619
Program incentives		$ 15,457,880
Measure costs		
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	$ 0	
Non-energy benefits		
Total	**$ 187,904,906**	**$ 18,952,499**
Net benefit	**$168,952,407**	
Benefit-cost ratio	**9.91**	

Source: E3 analysis; see Appendix C.

3.1.5 Calculating the RIM

The RIM examines the potential impact the energy efficiency program has on rates overall. The net benefits are the avoided cost of energy (same as PACT). The net costs include the overhead and incentive costs (same as PACT), but also include utility lost revenues from customer bill savings. The result of the SCE program is a loss of $109 million and a benefit-to-cost ratio of 0.63. This result suggests that, all other things being equal, the hypothetical impact of the program on rates would be for rates to increase. However, in practice, non-participants are unaffected until rates are adjusted through a rate case or a decoupling mechanism. In the long term, energy efficiency may reduce the capacity needs of the system; this can lead to either higher or lower rates to non-participants depending on the level of capital costs saved. Energy efficiency can be a lower-cost investment than other supply-side resources to meet customer demand, thereby keeping rates lower than they otherwise would be. (This is discussed in more detail in Section 3.2.2.) Thus it is important to recognize the RIM as examining the potential impacts on rates, but also recognizing that a negative RIM does not necessarily mean that rates will actually increase. Section 6.3 discusses impacts over time in greater detail. Table 3-8 breaks down the costs and benefits included in the RIM.

Table 3-8. Ratepayer Impact Measure for SCE Residential Energy Efficiency Program

RIM Calculations		
	Benefits	**Costs**
Program overhead		$ 3,494,619
Program incentives		$ 15,457,880
Measure costs		
Energy savings (net)	$ 187,904,906	
Bill savings (net)		$ 278,187,587
Monetized emissions (net)	$ 0	
Non-energy benefits		
Total	**$ 187,904,906**	**$ 297,140,085**
Net benefit	**($109,235,180)**	
Benefit-cost ratio	**0.63**	

Source: E3 analysis; see Appendix C.

3.1.6 Calculating the TRC

The TRC reflects the total benefits and costs to all customers (participants and non-participants) in the SCE service territory. The key difference between the TRC and the PACT is that the former does not include program incentives, which are considered zero net transfers in a regional perspective (i.e., costs to the utility and benefits to the customers). Instead, the TRC includes the net measure costs of $41 million. Net benefits in the TRC are the avoided costs of energy, $188 million. The regional perspective yields an overall benefit of $143 million and a benefit-to-cost ratio of 4.21. In California, the TRC includes an adder that internalizes the benefits of avoiding the emission of NO_x, CO_2, sulfur oxides (SO_x), and volatile organic compounds (VOCs). The adder is incorporated into energy savings (and not broken out as a separate category).[3] In many jurisdictions, the avoided costs are based on a market price that is presumed to implicitly include emissions permit costs and an explicit calculation of permit costs for regulated emissions is not made. The TRC shows that overall benefits are four times greater than total costs (a lower benefits-to-cost ratio than the PACT and PCT, but still positive overall). Table 3-9 shows the costs and benefits included in the TRC calculation.

Table 3-9. Total Resource Cost Test for SCE Residential Energy Efficiency Program

TRC Calculations		
	Benefits	**Costs**
Program overhead		$ 3,494,619
Program incentives		
Measure costs (net)		$ 41,102,993
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	(included in energy savings above)	
Non-energy benefits		
Total	**$ 187,904,906**	**$ 44,597,612**
Net benefit	**$143,307,294**	
Benefit-cost ratio	**4.21**	

Source: E3 analysis; see Appendix C.

3.1.7 Calculating the SCT

In California, the avoided costs of emissions are included directly in energy savings. These benefits are included in both TRC and SCT values, and as a result, their test outputs are the same (see Table 3-10).

Table 3-10. Societal Cost Test for SCE Residential Energy Efficiency Program

SCT Calculations		
	Benefits	**Costs**
Program overhead		$ 3,494,619
Program incentives		
Measure costs (net)		$ 41,102,993
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	(included in energy savings above)	
Non-energy benefits (net)	$ 0	
Total	**$ 187,904,906**	**$ 44,597,612**
Net benefit	**$143,307,294**	
Benefit-cost ratio	**4.21**	

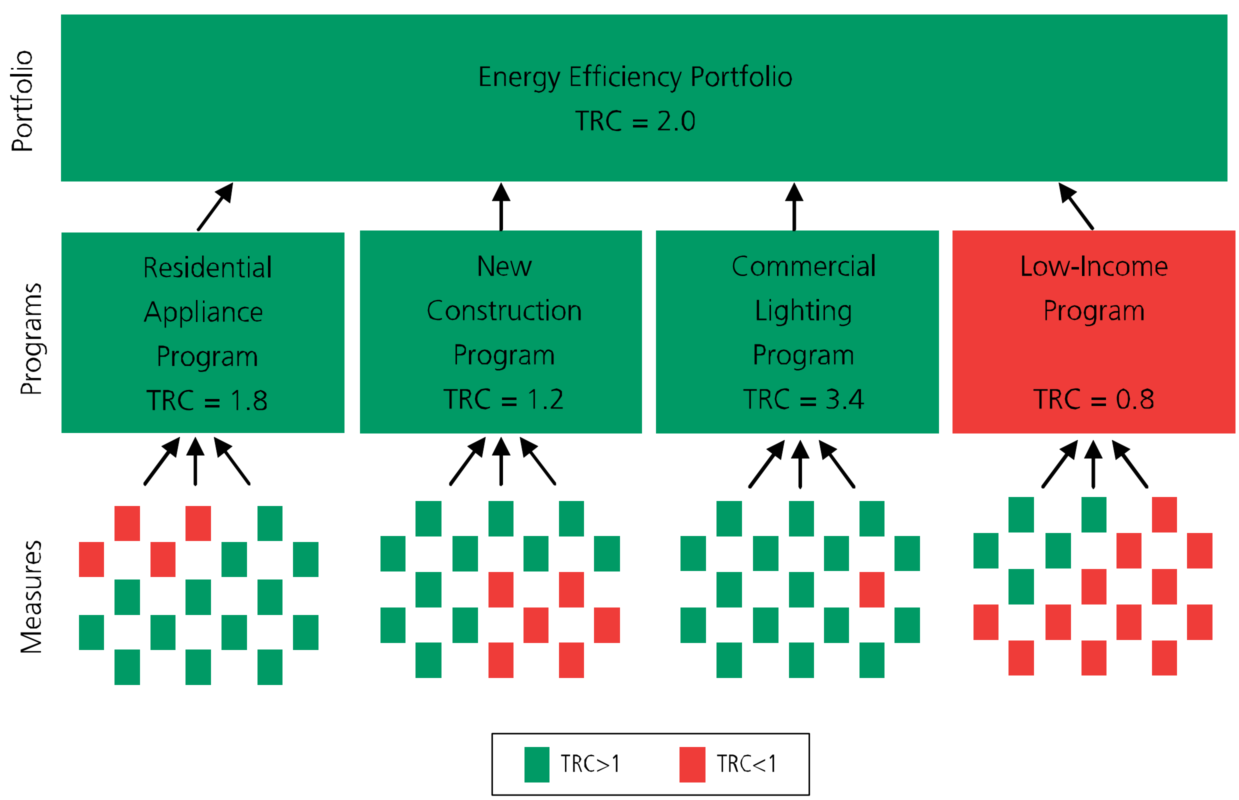
Source: E3 analysis; see Appendix C.

3.2 Considerations When Using Cost-Effectiveness Tests

3.2.1 Application of Cost-Effectiveness Tests

Cost-effectiveness tests can be applied at different points in the design of the energy efficiency portfolio, and the choice of when to apply each cost-effectiveness test has a significant impact on the ultimate set of measures offered to customers. In general, there are three places to evaluate the cost-effectiveness test: the "measure" level, the "program" level, and at the "portfolio" level. Evaluating cost-effectiveness at the measure level means that each individual component of a utility program must be cost-effective. Evaluation at the utility program level means that collectively the measures under a program must be cost-effective, but some measures can be uneconomical if there are other measures that more than make up for them. Evaluating cost-effectiveness at the portfolio level means that all of the programs taken together must be cost-effective, but individual programs can be positive or negative. Figure 3-1 illustrates a hypothetical portfolio in which cost-effectiveness is evaluated at the portfolio level, allowing some measures and programs that are not cost-effective even as the overall portfolio remains positive. If cost-effectiveness were evaluated at a measure level, those measures in red—the low-income program—could be eliminated as not cost-effective and would not be offered to customers.

Figure 3-1. Hypothetical Cost-Effectiveness at Measure, Program, and Portfolio Levels



Applying cost-effectiveness tests at the measure level is the most restrictive. With this approach, the analyst or policy-maker is explicitly or implicitly emphasizing the cost-effectiveness rather than the total energy savings of the efficiency portfolio. In contrast, applying cost-effectiveness tests at the portfolio level allows utilities greater flexibility to experiment with different strategies and technologies and results in greater overall energy savings, though at the expense of a less cost-effective portfolio overall. California applies the cost-effectiveness tests at the portfolio level specifically to allow and encourage the implementation of emerging technology and market transformation programs that promote important policy goals but do not themselves pass the TRC or PCT.

Strictly applying cost-effectiveness at the measure or even the program level can often result in the need for specific exceptions. At the measure level, variations in climate, building vintage, building type and end use may affect the cost-effectiveness of a measure. For marketing clarity, a rebate might be provided service-territory-wide even if some eligible climate zones and customer types are not cost-effective since differentiating among customer types may complicate the advertising message and make the program less effective (the program designers make sure the measure is cost-effective overall). At the program level, some programs—such as low-income programs—generally need higher incentive levels and marketing focus and may not be cost-effective, but are desired in the overall portfolio for social equity and other policy reasons. Similarly, some programs, such as those for emerging technologies or Home Performance with ENERGY STAR, ramp up slowly over time and typically do not achieve cost-effectiveness within the first three years, but do provide energy efficiency benefits. Also, the program and portfolio approaches make it easier to include supporting programs such as informational campaigns that raise overall awareness and complement other programs, but may not be cost-effective on a stand-alone basis.

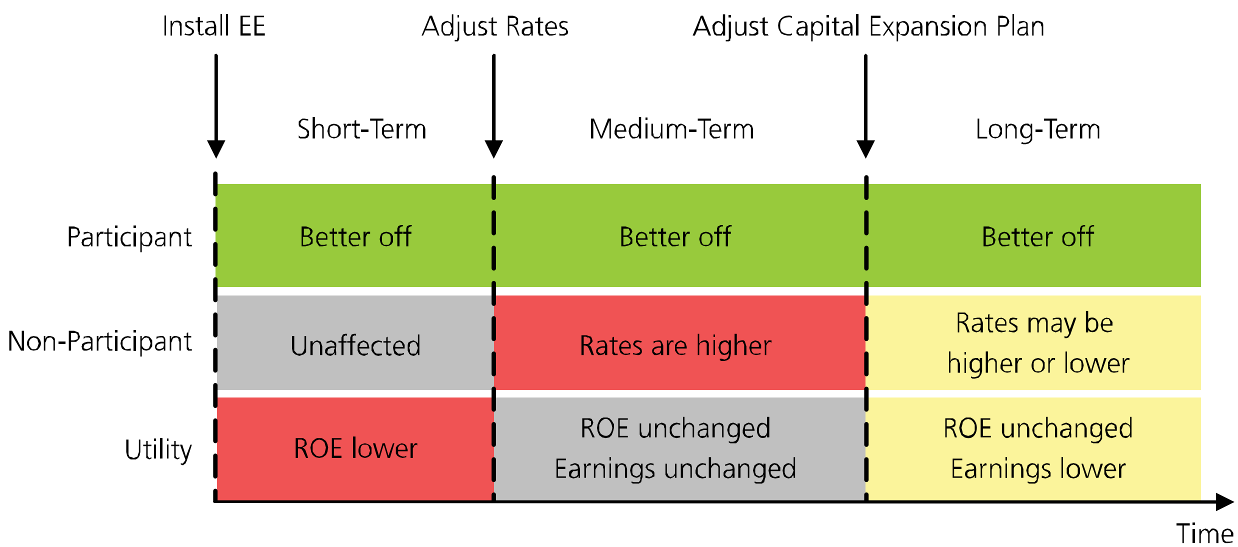
Summing up the benefits of multiple measures at the program level may require some adjustment for what are known as “interactive effects” between related measures. Interactive effects occur when multiple measures installed together affect each other’s impacts. When measures affect the same end use, their combined effect when implemented together may be less than the sum of each measure’s individually estimated impact. An insulation and air conditioning measure may each save 500 kilowatt-hours (kWh) individually, but less than 1,000 kWh when installed together. Alternatively, some measures may have additional benefits when other end uses are also present (i.e., “interactive effects”). For example, replacing incandescent bulbs with compact fluorescent light bulbs (CFLs) also reduces cooling loads in buildings with air conditioning.

3.2.2 Impacts Over Time of the Distribution Tests

Cost-effectiveness tests are evaluated on a life-cycle basis; however, they do not show the way impacts vary or adjust over time. As a result, it is important to recognize the ways in which program impacts may vary over time in order to properly interpret cost-effectiveness test results. For example, the RIM estimates the impact of the energy efficiency program on non-participants. Yet non-participants are actually unaffected until rates are adjusted through a rate case or a decoupling mechanism. Figure 3-2 illustrates the distributional impacts on the participant, non-participant, and utility over time in the common test-result case where energy efficiency has a PCT above 1 and a RIM below 1.[4]

Consider three time periods from the point at which the energy efficiency measure is first installed: the short term, medium term, and long term. The short term is defined as the period between installing the energy efficiency and adjusting the rate levels. The medium term begins once rates are adjusted and lasts until the change in energy efficiency results in an adjustment to the capital plan. The long term begins once the capital expansion plan has been changed.

Figure 3-2. Timeline of Distributional Impacts When PCT > 1 and RIM < 1



From a participant perspective, because the PCT is above 1.0, the participant is better off once an investment in energy efficiency is made, as the utility bill is lower than it would have been throughout the time horizon. In the short term, the non-participant is indifferent since rates have not been adjusted.[5] However, because the RIM is below 1.0, the utility is saving less than the drop in revenue from the participant and will therefore have lower return on equity (ROE), or debt-coverage ratio (DCR) for a public utility, compared to the case without energy efficiency. Note that for utilities with decoupling mechanisms or annual fuel cost adjustments, some or all of the rate impact may be felt before the next regular rate case cycle.

In the medium term, rates will be increased to hit the target ROE or DCR and the utility will be indifferent to the energy efficiency. This rate increase, however, affects the non-participating customers who have the same consumption as they otherwise would have, but now face higher rates. Finally, in the long term, energy efficiency may reduce the capacity needs of the system, as the capital expansion requirements of the utility are reduced. The long-term rate impact will depend on the level of fixed capital costs included in the avoided costs to value the energy savings. If the avoided costs include the long-term capacity cost savings realized through energy efficiency, a RIM ratio below 1.0 would indicate that rates will be higher in the long term. In many cases, however, avoided costs are based primarily on market prices, which tend to represent a short-term view. Thus, it may be that energy efficiency will meet load growth at a lower cost than that of alternative utility investments, and rates will be lower than they otherwise would have been even if the RIM ratio is below 1.0. To the extent that less capital is needed, earnings will be lower for the utility since the utility will be smaller relative to the no-efficiency case. However, ROE or DCR will be unchanged in the long term since rates will be adjusted periodically based on the target ROE or DCR.

3.3 Notes

[1] PM10 is particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.

[2] Calculations of the cost tests were made by the paper's authors using a simplified analysis tool. This serves to illustrate the concepts, but may not match exactly what each utility has reported based on their own analysis.

[3] The inclusion of the environmental adder in the TRC is an effort to directly internalize the externalities of environmental impacts into California's primary cost test, which is the TRC (see Section 5.1.1).

[4] More detailed analysis of impacts over time can be evaluated with the National Action Plan for Energy Efficiency's Energy Efficiency Benefits Calculator, using a set of assumptions that can be modified to fit a particular utility. See <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/calculator.html>.

[5] If the load forecasts used in rate-making are adjusted to reflect projected efficiency savings, rates may increase in the short term as well.

4: Key Drivers in the Cost-Effectiveness Calculation

In addition to the cost-effectiveness tests themselves, there are a number of choices in developing the costs and benefits that can significantly affect the cost-effectiveness results. This chapter describes some of the major choices available to analysts and policy-makers; it is a resource and reference for identifying and better understanding the variations in possible terms and approaches and developing a more robust understanding of possible evaluation techniques and their trade-offs. Because energy efficiency programs vary in different energy sectors and have different embedded savings and cost values, the variations on these terms are considerable. Thus, this chapter cannot be a step-by-step guide of all possible conditions.

Issues covered in this chapter include:

- Which benefits to include in each cost-effectiveness test.
- Whether to emphasize accuracy or transparency.
- Which methodology to use to forecast future benefits of energy and capacity savings.
- What time period to consider when assessing costs and benefits.
- Whether to determine demand- and supply-side resource requirements in the same analysis (true "integrated resource planning").
- Whether to use a public, non-proprietary data set to develop the benefits, or rely on proprietary forecasts and estimates.
- Which discount rates to use in NPV analysis.
- Whether to incorporate non-energy benefits (NEBs) and costs in the calculation.
- What NTG to use.
- Whether to include CO_2 emissions reductions in the analysis.
- Whether to include RPS procurement costs in the analysis.

Ultimately, the types of costs, benefits, and methodology used depend on the policy goals. This chapter outlines the key terms that will need to be addressed in weighing and evaluating efficiency programs. It also provides a discussion of key factors in applying cost-effectiveness test terms.

4.1 Framework for Cost-Effectiveness Evaluation

The typical approach for quantifying the benefits of energy efficiency is to forecast long-term "avoided costs," defined as costs that would have been spent if the energy efficiency savings measure had not been put in place. For example, if an electric distribution utility expects to purchase energy at a cost of $70 per megawatt-hour (MWh) on behalf of customers, then $70/MWh is the value of reduced purchases from energy efficiency. In addition, the utility may not have to purchase as much system capacity (ICAP or UCAP),[1] make as many upgrades to distribution or transmission systems, buy as many emissions offsets, or incur as many other costs. All such cost savings resulting from efficiency are directly counted as "avoided cost" benefits. In addition to the directly counted benefits, the state regulatory commission or governing councils may request that the utility account for indirect cost savings that are not priced by the market (e.g., reduced CO_2 emissions). For additional information on avoided costs, refer to the National Action Plan's *Guide to Resource Planning with Energy Efficiency* (National Action Plan for Energy Efficiency, 2007b [Chapter 2]).

4.2 Choosing Which Benefits to Include

There are two main categories of avoided costs: energy-related and capacity-related avoided costs. Energy-related avoided costs involve market prices of energy, losses, natural gas commodity prices, and other benefits associated with energy production such as reduced air emissions and water usage. Capacity-related avoided costs involve infrastructure investments such as power plants, transmission and distribution lines, pipelines, and liquefied natural gas (LNG) terminals. Environmental benefits make up a third category of benefits that are frequently included in avoided costs. Saving energy reduces air emissions including GHGs, and saving capacity addresses land use and siting issues such as new transmission corridors and power plants.

Table 4-1 lists the range of avoided cost components that may be included in avoided cost benefits calculations for electricity and natural gas energy efficiency programs. The most commonly included components (and which comprise the majority of avoided costs) for electric utilities are both energy and capacity. Natural gas utilities will typically include energy and may or may not include the capacity savings.[2] Depending on the utility and the focus of the state regulatory commission or governing council, others may also be included.

Table 4-1. Universe of Energy and Capacity Benefits for Electricity and Natural Gas

Electricity Energy Efficiency	
Energy Savings	**Capacity Savings**
Market purchases or fuel and operation and maintenance costs	Capacity purchases or generator construction
System losses	System losses (peak load)
Ancillary services related to energy	Transmission facilities
Energy market price reductions	Distribution facilities
Co-benefits in water, natural gas, fuel oil, etc.	Ancillary services related to capacity
Air emissions	Capacity market price reductions
Hedging costs	Land use
Natural Gas Energy Efficiency	
Energy Savings	**Capacity Savings**
Market purchases at city gate	Extraction facilities
Losses	Pipelines
Air emissions	Cold weather action/pressurization activities
Market price reductions	Storage facilities
Co-benefits in water, natural gas, fuel oil, etc.	LNG terminals
Hedging costs	

Note: More detail on each of these components can be found in Chapter 3 of the Action Plan's *Guide to Resource Planning with Energy Efficiency* (National Action Plan for Energy Efficiency, 2007b).

Most states select a subset to analyze from within this “universe” of benefits when evaluating energy efficiency. No state considers them all. The most important factor in choosing the components is to inform the decisions on energy efficiency given the policy backdrop and situation of the state. As an example of how calculations may be adopted to specific conditions, California chose to include market price reduction effects in evaluating energy efficiency programs during the California Energy Crisis. Similarly, large capital projects such as LNG terminals or power plants, or a focus on GHGs or local environment, might lead to emphasizing these components over others. There may be diminishing value to detailed analysis of small components of the avoided cost that will not change the fundamental decisions.

4.3 Level of Complexity When Forecasting Avoided Costs

Within the avoided cost framework, there are many ways to estimate the benefits. The approach may be as simple as estimating the fixed and variable costs of displaced generation and using them as the avoided costs (as is done in Texas). An alternative approach is to use a more sophisticated integrated resource planning (IRP) approach that simultaneously evaluates both supply- and demand-side investments. This IRP analysis may include a simulation of the utility system with representation of all of the generation, transmission constraints, and loads over time (for example, see the Northwest Power Planning and Conservation Council 5th Power Plan[3] or PacifiCorp Integrated Resource Planning[4]). This requires a much more complex set of analysis tools, but provides more information on the right timing, desired quantity, and value of energy efficiency with respect to the existing utility system and its expected future loads.

In general, more sophisticated and accurate estimates of benefits are better. However, other considerations include the following:

- **Availability of resources** needed to complete the analysis and stakeholders’ review before adoption may be a problem in states without intervener compensation.
- **Time taken to complete** the analysis with sophisticated IRP approaches could delay implementation of energy efficiency. The regulatory landscape in many states is littered with IRP proceedings that are contentious and have taken years to complete.
- **Transparency of the approach** to a broad set of stakeholders is also valued and may be easier to achieve without sophisticated models to achieve broader support.

4.4 Forecasts of Avoided Costs

Depending on the utility type and market structure in a region, there are a number of methodology options for developing avoided natural gas and electricity costs. The first approach is to use forward and futures market data, which are publicly available and transparent to all stakeholders. However, energy efficiency is likely to have a life longer than available market prices, and a supplemental approach will also be needed to estimate long-term costs.

The second approach is to use public or private long-run forecast of electricity and natural gas costs, such as those produced by the Department of Energy’s Energy Information Agency and many state agencies (utilities participating in wholesale markets will also have proprietary forward market forecasts to inform trading activities).

The third approach is to develop simple long run estimates of future electricity value by choosing a typical "marginal resource" such as a combined cycle natural gas plant and forecasting its variable costs into the future. A more sophisticated variation would be to incorporate production simulation modeling of the electricity system into this analysis. Overall, it is important to understand the underlying assumptions of the forecasting approach and assess whether or not these assumptions are appropriate for the intended purpose. Table 4-2 summarizes avoided costs approaches by utility type and each is described in more detail below.

Table 4-2. Approaches to Valuing Avoided Energy and Capacity Costs by Utility Type

Utility Type	Near-Term Analysis (i.e., Market Data Available)	Long-Term Analysis (i.e., No Market Data Available)
Distribution electric or natural gas utility	Current forward market prices of energy and capacity	Long-term forecast of market prices of energy and capacity
Electric vertically integrated utility	Current forward market prices of energy and capacity *or* Expected production cost of electricity and value of deferring generation projects	Long-term forecast of market prices of energy and capacity *or* Expected production cost of electricity and value of deferring generation projects

4.4.1 Market Data

For utilities that are tightly integrated into the wholesale energy market, forward market prices provide a good basis for establishing avoided costs. If the utility is buying electricity, energy efficiency reduces the need to purchase electricity. If the utility can sell excess electricity, energy savings enables additional sales, resulting in incremental revenue. In either case, the market price is the per kWh value of energy efficiency. Forward market electricity prices are publicly available through services such as Platt's "Megawatt Daily," which surveys wholesale electricity brokers. This data is typically available extending three or four years into the future depending on the market.

The market price is also a good approach for natural gas utilities. The NYMEX futures market for natural gas provides market prices as far as 12 years in advance by month.[5] The market currently has active trading daily over the next three to five years. The NYMEX market also includes basis swaps that provide the price difference between Henry Hub and most delivery points in the United States.[6] Some analysts hesitate to use market data such as NYMEX beyond the period of active trading for fear that low volume of trading creates liquidity problems and prices that are not meaningful. While more liquid markets provide more rigor in the prices, the less liquid long-term markets are still available for trading and are therefore unbiased estimates of future market prices and may still be the best source of data.

Market prices provide a relatively simple, transparent, and readily accessible basis for quantifying avoided costs. On the other hand, market prices tend to be influenced primarily by current market conditions and variable operating costs, particularly in the near term. Market prices alone may not adequately represent long-term and/or fixed operating costs. The production simulation and proxy plant approaches described below provide alternative approaches that address long-term fixed costs.

4.4.2 Production Simulation Models

For self-resourced electric utilities that do not have wholesale market access or actively trade electricity, a “production simulation” forecast may be the best approach to forecast energy costs. A production simulation model is a software tool that performs system dispatch decisions to serve load at least cost, subject to constraints of transmission system, air permitting, and other operational parameters. The operating cost of the “marginal unit” in each hour or time period is used to establish the avoided cost of energy. The downside of production simulation models is that they are complex, rely on sophisticated algorithms that can appear as a “black box” to stakeholders, and have to be updated when market prices of inputs such as natural gas change. In addition, these types of models can have difficulty predicting market prices since the marginal energy cost is based on production cost, rather than supply and demand interactions in a competitive electricity market. If production simulation produces prices that differ from those actually seen in the market, energy efficiency can end up facing a cost hurdle that differs from the hurdles faced by supply-side resources. Long-term natural gas forecasts also often rely on production simulation to model regional supply, demand, and transportation dynamics and estimate the equilibrium market prices.

4.4.3 Long-Run Marginal Cost and the “Proxy Plant”

Developing a “proxy plant” is an alternative to production simulation approaches and may be used when market data is not available or appropriate. Under this approach, a fixed hypothetical plant is used as a proxy for the resources that will be built to meet incremental load.[7] Selecting the proxy-plant, the construction costs, financial assumptions, and operating characteristics are all assessed from its characteristics. As an example, the variable costs of a combined cycle natural gas plant may be used as a proxy for energy costs. The annual fixed cost of a combustion turbine may be used as a proxy for capacity costs. Several methods can be used to allocate fixed costs, adjust the variable operating costs, or otherwise shape the costs of the plant(s) across different time-of-use (TOU) periods. These methods include applying market price or system load shapes, loss of load probabilities, or marginal heat rates to vary prices by TOU. Another commonly used method is the peaker methodology, which uses an allocation of the capacity costs associated with peaking resources (typically combustion turbines) and the marginal system energy cost by hour (system lambda) to estimate avoided electricity costs in each hour or TOU period. These costs are then used to estimate the costs of the energy and capacity in the avoided costs calculations. The proxy plant approach is more transparent and understandable to many stakeholders (particularly in comparison to production simulation). The proxy plant approach may be used in conjunction with market data, to estimate costs for the periods beyond the time horizons when existing market data are available.

4.4.4 Proprietary and Public Forecasts

The easiest approach for a utility to develop long-term avoided costs may be to use its own internal forecast of market prices. This approach provides estimates of avoided cost that are closely linked to the utility operations. However, the methodology may be confidential since utilities involved in procuring electricity or natural gas on the market may not to reveal their expectations of future prices publicly. Therefore, the use of internal forecasts can significantly limit the stakeholder review process for evaluation of energy efficiency programs.

Public forecasts of avoided costs may also be used to develop a more open process for energy efficiency evaluation and planning. California, Texas, the Northwest Power Planning Council, Ontario, and others use a non-proprietary methodology. An open process allows non-utility stakeholders to evaluate and comment on the methodology, thereby increasing the confidence that the analysis is fair. This approach also makes it possible for energy efficiency contractors to evaluate the cost-effectiveness of proposed energy efficiency upgrades. Unfortunately, this open process may diverge from internal forecasts and introduce some discrepancy between the publicly adopted numbers and those actually used by utilities in resource planning and procurement decisions. States balance these concerns and generally commit to one path or the other.

Policy-makers may also rely on existing publicly available forecasts of electricity or natural gas. The most universal source of forecasts is the Annual Energy Outlook (AEO), provided by the Department of Energy's Energy Information Agency.[8] This public forecast provides regional long-term forecasts of electricity and natural gas. In addition to the AEO, state energy agencies or regional groups may provide their own independent forecasts, which may include sensitivity analysis. Some parties, however, view publicly developed forecasts with some skepticism, as they may be seen as being overly influenced by political considerations or the compromises necessary to gain wide support in a public process.

4.4.5 Risk Analysis

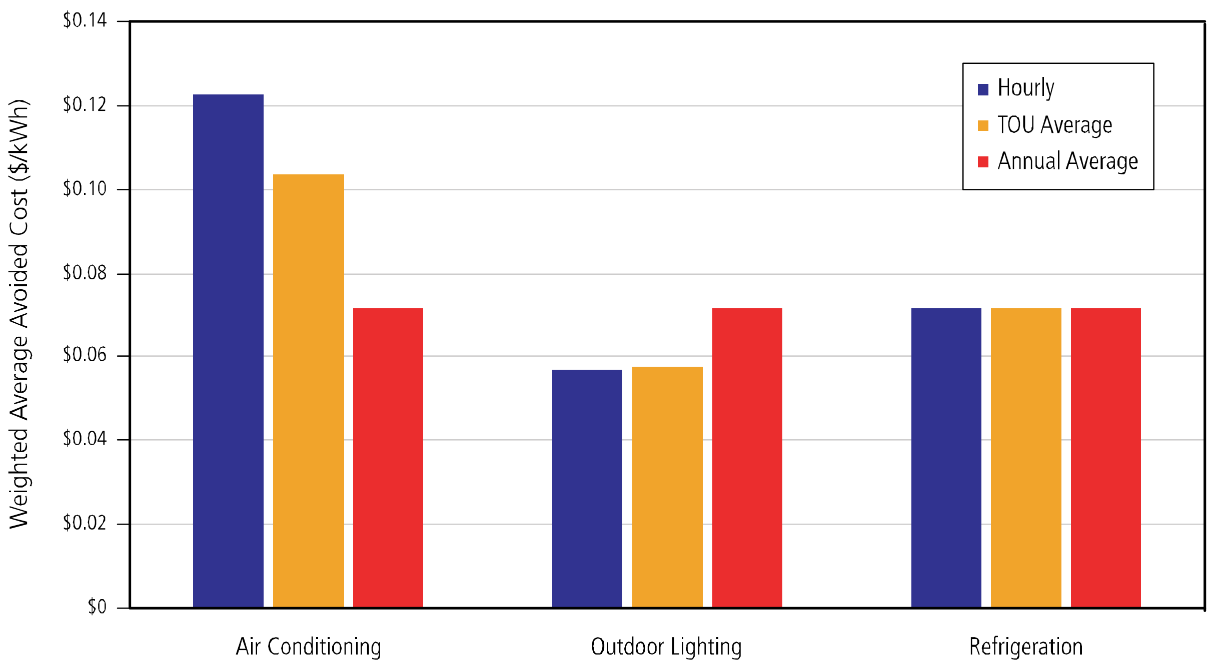
Electricity and natural gas prices are quite volatile and subject to cyclical ups and downs. In reducing load, energy efficiency also reduces a utility's exposure to fluctuating market prices. This provides an option or hedge value that can be quantified with risk analysis, but which is omitted when a single forecast of avoided costs is used.

Increasingly, utilities have used scenario and risk analysis to assess the benefits of different investment options under a range of future scenarios. One of the simpler approaches is to compare the cost-effectiveness results under multiple scenarios, using a high, expected, and low energy price forecast for example. More advanced techniques, such as Monte Carlo simulation, may be used to evaluate the performance of various resource plans under a wide range of possible outcomes.

4.5 Area- and Time-Specific Marginal Costs

For all of the forecasting approaches for avoided costs, the analyst must decide the level of disaggregation by area and time used in developing the forecasts. The marginal costs of electricity can vary significantly hour to hour and both electricity and natural gas prices vary by area and time of year. Similarly, the load reductions provided by energy efficiency measures also vary by season and time of day. Figure 4-1 shows the differences that can result when using hourly, TOU, and annual average avoided costs for different end uses, based on a study of air conditioning, outdoor lighting, and refrigeration end uses in California. The significance of using either TOU or average annual costs is highly dependent on the end use and demand/cost characteristics of the region in question. In California, the decision to use hourly avoided costs was made in order to appropriately value air conditioning energy efficiency.[9] This approach almost doubles the value of air conditioning measures relative to a flat annual average assessment of avoided cost (~$0.12/kWh vs. ~$0.07). In the case of other end uses, such as outdoor lighting efficiency, there is very little difference between hourly and TOU costs for end uses that operate evenly within a 24-hour period (e.g., refrigeration), there is no difference in method.

Figure 4-1. Implication of Time-of-Use on Avoided Costs



Source: California Proceeding on Avoided Costs of Energy Efficiency; R.04-04-025.

Another consideration of time-dependent avoided cost analysis is the need to correctly evaluate the tradeoffs between different types of energy efficiency measures. Hourly avoided costs are highly detailed, capturing the cost variance within and across major time periods. Annual average costs ignore the timing of energy savings. In the example above, using an annual average method, CFLs and outdoor lighting efficiency would receive the same value as air conditioning energy efficiency, while in actuality air conditioning energy efficiency is much more valuable to the system overall because it reduces the peak load significantly. The use of hourly avoided costs in this case reveals the large potential avoided cost value of air conditioning savings relative to other efficiency measures.

4.6 Net Present Value and Discount Rates

A significant driver of overall cost-effectiveness of energy efficiency is the discount rate assumption. Each cost-effectiveness test compares the NPV of the annual costs and benefits over the life of an efficiency measure or program. Typically, energy efficiency measures require an upfront investment, while the energy savings and maintenance costs accrue over several years. The calculation of the NPV requires a discount rate assumption, which can be different for the stakeholder perspective of each cost-effectiveness test.

As each perspective portrays a specific stakeholder's view, each perspective comes with its own discount rate. The five cost-effectiveness tests are listed in Table 4-3, along with the appropriate discount rate and an illustrative value. Using the appropriate discount rate is essential for correctly calculating the net benefits of an investment in energy efficiency.

Table 4-3. The Use of Discount Rates in Cost-Effectiveness Tests

Tests and Perspective	Discount Rate Used	Illustrative Value	Present Value of $1 a Year for 20 Years*	Today's Value of the $1 Received in Year 20
PCT	Participant's discount rate	10%	$8.51	$0.15
RIM	Utility WACC	8.5%	$9.46	$0.20
PACT	Utility WACC	8.5%	$9.46	$0.20
TRC	Utility WACC	8.5%	$9.46	$0.20
SCT	Social discount rate	5%	$12.46	$0.38

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

* This value is the same as not having to purchase $1 of electricity per year for 20 years.

Three kinds of discount rates are used, depending on which test is being calculated. For the PCT, the discount rate of an individual or business is used. For a household, this is taken to be the consumer lending rate, since this is the debt cost that a private individual would pay to finance an energy efficiency investment. It is typically the highest discount rate used in the cost-effectiveness tests. However, since there are potentially many different participants, with very different borrowing rates, it can be difficult to choose a single appropriate discount rate. Based on the current consumer loan market environment, a typical value may be in the 8 to 10 percent range (though a credit card rate might be much higher). For a business firm, the discount rate is the firm's weighted average cost of capital (WACC). In today's capital market environment, a typical value would be in the 10 to 12 percent range—though it can be as high as 20 percent, depending on the firm's credit worthiness and debt-equity structure. Businesses may also assume higher discount rates if they perceive several attractive investment opportunities as competing for their limited capital dollars. Commercial and industrial customers can have payback thresholds of two years or less, implying a discount rate well in excess of 20 percent.

For the SCT, the social discount rate is used. The social discount rate reflects the benefit to society over the long term, and takes into account the reduced risk of an investment that is spread across all of society, such as the entire state or region. This is typically the lowest discount rate. For example, California uses a 3 percent real discount rate (~5 percent nominal) in evaluating the cost-effectiveness of the Title 24 Building Standards.

Finally, for the TRC, RIM, or PACT, the utility's average cost of borrowing is typically used as the discount rate. This discount rate is typically called the WACC and takes into account the debt and equity costs and the proportion of financing obtained from each. The WACC is typically between the participant discount rate and the social discount rate. For example, California currently uses 8.6 percent in evaluating the investor-owned utility energy efficiency programs.

Using these illustrative values for each cost-effectiveness test, the third column of Table 4-3 shows the value of receiving $1 per year for 20 years from each perspective. This is analogous to the value of not having to purchase $1 of electricity per year. From a participant perspective assuming a 10 percent discount rate, this stream is worth $8.51; from a utility perspective, it is worth $9.46; and from a societal perspective, it is worth $12.46. The effect of the discount rate increases over time. The value today of the $1 received in the 20th year ranges from $0.15 from the participant perspective to $0.38 in the societal perspective, more than twice as much. Since the present value of a benefit decreases more over time with higher discount rates, the choice of discount rate has a greater impact on energy efficiency measures with longer expected useful lives.

4.7 Establishing the Net-to-Gross Ratio

A key requirement for cost benefit analysis is estimating the NTG. The NTG adjusts the cost-effectiveness results so that they only reflect those energy efficiency gains that are attributed to, and are the direct result of, the energy efficiency program in question. It gives evaluators an estimate of savings achieved as a direct result of program expenditures by removing savings that would have occurred even absent a conservation program. Establishing the NTG is critical to understanding overall program success and identifying ways to improve program performance. For more information on NTG in the context of efficiency program evaluation, see Chapter 5 of the National Action Plan for Energy Efficiency's *Model Energy Efficiency Program Impact Evaluation Guide* (National Action Plan for Energy Efficiency, 2007c).

Gross energy impacts are the changes in energy consumption and/or demand that result directly from program-related actions taken by energy consumers that are exposed to the program. Estimates of gross energy impacts always involve a comparison of changes in energy use over time among customers who installed measures versus some baseline level of usage.

Net energy impacts are the percentage of the gross energy impact that is attributable to the program. The NTG reduces gross energy savings estimates to reflect three types of adjustments:

- Deduction of energy savings that would have been achieved even without a conservation program.
- Deduction of energy savings that are not actually achieved in real world implementation.
- Addition of energy savings that occur as an indirect result of the conservation program.

Key factors addressed through the NTG are:

- **Free riders.** A number of customers take advantage of rebates or cost savings available through conservation programs even though they would have installed the efficient equipment on their own. Such customers are commonly referred to as "free riders."
- **Installation rate.** In many cases the customer does not ultimately install the equipment. In other cases, efficient equipment that is installed as part of an energy conservation program is later bypassed or removed by the customer. This is common for CFL programs.

- **Persistence/failure.** A certain percentage of installed equipment can be expected to fail or be replaced before the end of its useful life. Such early failure reduces the achieved savings as compared to pre-installation savings estimates.

- **Rebound effect.** Some conservation measures may result in savings during certain periods, but increase energy use before or after the period in which the savings occur. In addition, customers may use efficiency equipment more often due to actual or perceived savings.

- **Take-back effect.** A number of customers will use the reduction in bills/energy to increase their plug load or comfort by adjusting thermostat temperatures.

- **Spillover.** Spillover is the opposite of the free rider effect: customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program.

4.8 Codes and Standards

Another way to encourage energy efficiency is to adopt increasingly strict codes and standards for energy use in buildings and appliances. This process is occurring in parallel with energy efficiency programs in most states, as each approach has its advantages and disadvantages. Codes and standards can be adopted for the state as a whole and do not demand the same level of state or utility funding as incentive programs. They do, on the other hand, impose regulatory and compliance costs on businesses and residents. Codes and standards generally involve a more complicated and potentially contentious legislative process than utility energy efficiency programs overseen by regulatory agencies. They also present enforcement challenges; local planning departments often do not have the staff, budget, or expertise to focus on state regulations related to energy use.

Increasingly strict codes and standards effectively raise the baseline that efficiency measures are compared against over time. This will reduce the energy savings and net benefits of efficiency measures, either by reducing the estimated savings or increasing the NTG.

4.9 Non-Energy Benefits and Costs

Conservation measures often have additional benefits beyond energy savings. These benefits include improved comfort, health, convenience, and aesthetics and are often referred to as non-energy effects (to include costs as well as benefits) or NEBs. None of the five cost-effectiveness tests explicitly recognizes changes in NEBs. Unless specifically cited, databases and studies generally exclude NEBs.

Examples of NEBs include:

- **From the customer perspective,** increased comfort, air quality, and convenience. For example, a demand response event that turns off air conditioning can reduce comfort and be a “cost” to the customer. Conversely, participants who gain improved heating and insulation can experience increased comfort, gaining an overall benefit.

- **From the utility perspective,** NEBs have been shown to reduce the number of shut-off notices issued or bill complaints received, particularly in low-income communities.

- **From a societal perspective,** efficiency programs can provide regional benefits in increased community health and improved aesthetics. On a larger scale, energy efficiency also reduces reliance on imported energy sources and provides national security benefits.

Studies attempting to estimate the value of NEBs are limited. Such studies often rely on participant surveys, which are designed to indicate their willingness to pay for NEBs or comparative valuation of various NEBs. Other studies rely on statistical analysis of survey data to estimate or "reveal" participant preferences toward NEBs. Both survey and statistical methods have significant limitations, and it is difficult to account for changing preferences across different income levels, cultural backgrounds, and household types. When values are not available, the judgment of regulators or program managers may be used. Examples of accounting for NEBs include decreasing costs or increasing benefits by a fixed percentage in the cost-effectiveness tests. To date, more emphasis has been placed on including NEBs than on non-energy costs. Nevertheless, as NEBs are incorporated in cost-effectiveness evaluation, non-energy costs should be evaluated on an equivalent basis. Examples of non-energy costs include reduced convenience and increased disposal or recycling costs.

4.10 Incentive Mechanisms

An area of growing interest in the application of cost-effectiveness tests is in establishing incentive mechanisms for utility efficiency programs. There exist two natural disincentives for utilities to invest in energy efficiency programs. First, energy efficiency reduces sales, which puts upward pressure on rates and can affect utility earnings. Second, utilities make money through a return on their capital investments or rate base. The financial disincentives for utilities are discussed thoroughly in the National Action Plan for Energy Efficiency's paper *Aligning Utility Incentives with Energy Efficiency Investment* (National Action Plan for Energy Efficiency, 2007a).

To address the reduced earnings from energy efficiency, states are increasingly exploring incentive mechanisms that allow a utility to earn a return on energy efficiency expenditures similar to the return on invested capital. The intent is to give the utility an equal (or greater) financial incentive to invest in energy efficiency as compared to traditional utility infrastructure.

The cost-effectiveness test results are increasingly being used as a metric to measure the incentive payment to the utility, based on the performance of the energy efficiency program. However, as discussed previously, no single cost-effectiveness test captures all of the goals of the efficiency program. Therefore, some states, such as California, have developed "weighting" approaches that combine the results of the cost-effectiveness tests. California has established a Performance Earnings Basis that is based on two-thirds of the TRC portfolio net benefits result and one-third of the PACT portfolio net benefits result. An incentive is then paid based on the utilities' combined results using this metric if the utilities' portfolio of savings meets or exceeds the utility commission's established energy savings goals.

When the cost-effectiveness tests are used in the payment of shareholder incentives, there will be additional scrutiny on the input assumptions and key drivers in the calculation. With this additional pressure, transparency and stakeholder review of the methodology becomes more important. Finally, the cost-effectiveness tests' use and their weights must be considered with care to align the utility objectives with the goals of the energy efficiency policy.

4.11 Greenhouse Gas Emissions

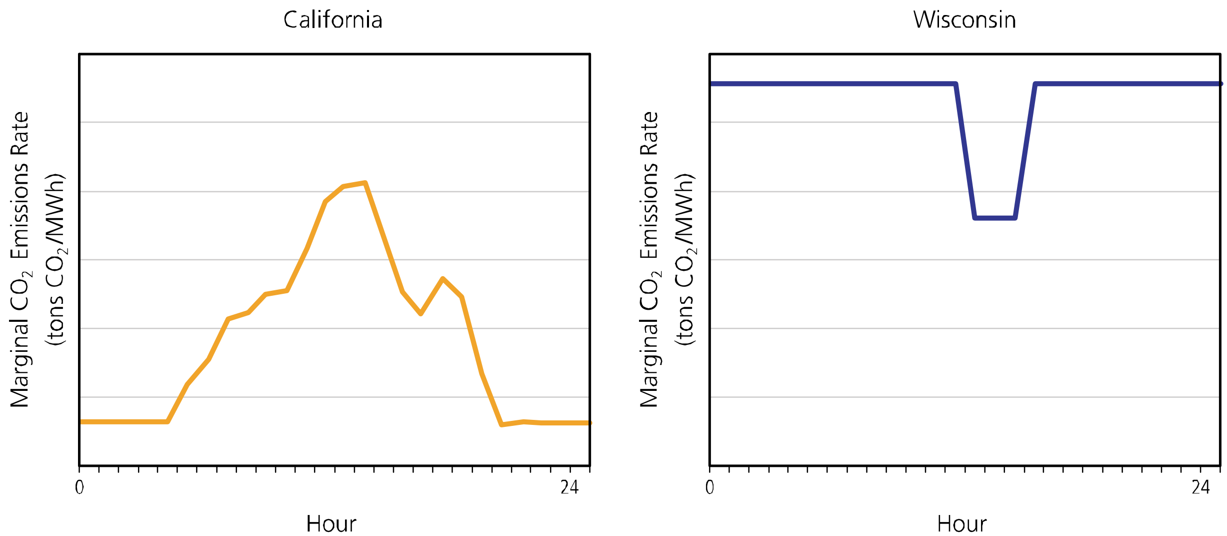
Another factor to consider when determining the cost-effectiveness of an energy efficiency program is how to value the program's effect on GHG emissions. The first step is to determine the quantity of avoided CO_2 emissions from the efficiency program. Once that quantity has been determined, its economic value can be calculated and added to the net benefits of the energy efficiency measures used to achieve the reductions. Currently, some jurisdictions use an explicit monetary CO_2 value in cost-benefit calculations, and some do not. California includes a forecast of GHG values in the avoided costs used to perform the cost-effectiveness tests and Oregon requires that future GHG compliance costs be explicitly considered in utility resource planning. Several utilities, including Idaho Power, PacifiCorp, and Public Service Company of Colorado, include GHG emissions and costs when evaluating supply- and demand-side options, including energy efficiency, in their IRP process.

The GHG emissions emitted through the end use of natural gas and heating oil are driven by the carbon content of the fuel and do not vary significantly by region or time of use. The GHG profiles of electricity generation do differ greatly by technology, fuel mix, and region. A very rough estimate of GHG emissions savings from energy efficiency can be obtained by multiplying the kWh saved by an average emission factor. Alternatively, it can be estimated based upon a weighted average of the heat rates and emission factors for the different types of generators in a utility's generation mix. Such "back of the envelope" methods are useful for agency staff and others who wish to quickly check that results from more sophisticated methods are approximately accurate.

A formal cost-effectiveness evaluation uses marginal emission rates that more accurately reflect the change in emissions due to energy efficiency and have an hourly profile that varies by region. For states in which natural gas is both a base load and peaking fuel, marginal emissions will be higher during peak hours because of the lower thermal efficiency of peaking plants, and therefore energy efficiency measures that focus their kWh savings on-peak will have the highest avoided GHG emissions per kWh saved. However, in states in which coal is the dominant fuel, off-peak marginal emission rates may actually be higher than on-peak if the off-peak generation is coal and on-peak generation is natural gas. Figure 4-2 illustrates this difference, comparing reported marginal emission rates for California and Wisconsin.

To date, monetary values for GHG emissions have been drawn primarily from studies and journal articles and applied in regulatory programs. While there is widespread agreement that GHG reduction policies are likely to impose some cost on CO_2 emissions, achieving consensus on a specific $/ton price for the electricity sector is challenging. As Congress and individual states consider specific GHG legislation, a number of the policy considerations that will affect the CO_2 price remain in flux.

Figure 4-2. Comparison of Marginal CO_2 Emission Rates for a Summer Day in California and Wisconsin



Source: Erickson et al. (2004).

Note: The on-peak marginal emissions rate of each state is set by natural gas peaking units. The off-peak rates are quite different, reflecting the dominance of coal base load generation in Wisconsin and natural gas combined cycle in California.

4.12 Renewable Portfolio Standards

An emerging topic in energy efficiency cost-effectiveness is how to treat the interdependence between energy efficiency and RPS. RPS goals are typically established state by state as a percentage of retail loads in a future target year (e.g., 20 percent renewable energy purchases by 2020). Unlike supply-side investments, energy efficiency, by reducing load, can reduce the amount of renewable energy that must be procured pursuant to RPS targets, thereby reducing RPS compliance cost.

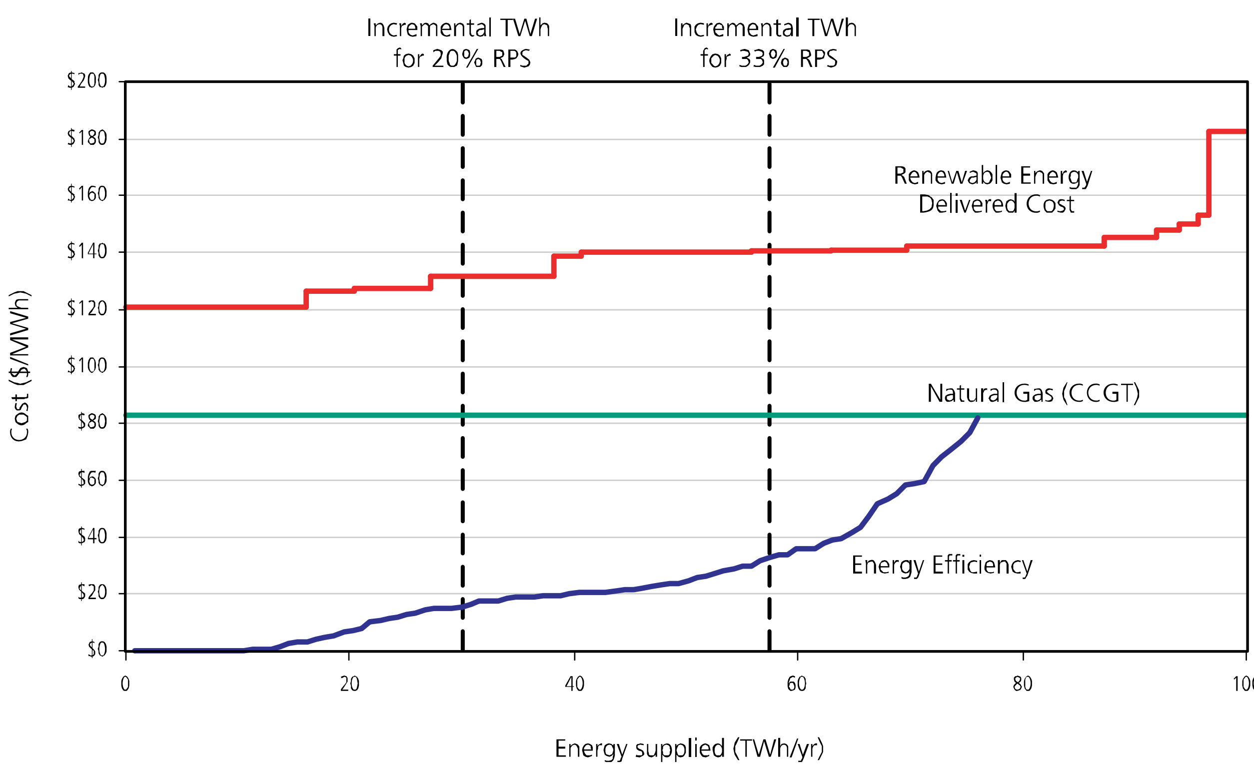
Some renewable technologies can provide energy at costs close to that of conventional generation. However, for many states, the marginal cost of complying with state RPS goals will be set either by more expensive technologies or by distant resources with significant transmission costs. When the cost of renewable energy needed to meet RPS goals is significantly higher than the avoided cost for conventional generation, energy efficiency provides additional savings by reducing RPS compliance costs.

The additional RPS-related savings from energy efficiency for California are illustrated in Figure 4-3. In California, as in many regions, the least-cost conventional base-load resource is combined cycle gas turbine (CCGT), shown here with a cost of \$82/MWh. The avoided costs against which energy efficiency has historically been evaluated are based on such conventional generation. This has limited the promotion of energy efficiency to technologies with costs below \$80/MWh. In practice, given limited budgets and staff, utilities have focused primarily on technologies with costs of \$40/MWh or below.

In comparison, the estimated cost of renewable energy needed to meet California's 20 percent RPS standard is over $130/MWh. So for every 1,000 MWh saved by energy efficiency, the utilities avoid the purchase 800 MWh of conventional generation at $82/MWh and 200 MWh of renewable generation at $130/MWh. Thus the RPS standard increases the cost of avoided energy purchases from $82/MWh to $92/MWh ($82/MWh + [130/MWh - $82/MWh] × 20%).

Utilities in California have begun to incorporate the higher cost of renewable generation in their internal evaluation of load reduction strategies. However, as in most jurisdictions, the cost of meeting RPS targets has not yet been formally included in the adopted avoided cost forecasts against which energy efficiency programs are officially evaluated.

Figure 4-3. Natural Gas, Energy Efficiency, and Renewable Supply Curves for California



Source: Mahone et al. (2008).

4.13 Defining Incremental Cost

In order to apply the avoided cost approach in evaluating benefits of energy efficiency cost-effectiveness, the analyst must also determine the incremental cost of the measures. Energy efficiency portfolio costs are easier to evaluate than benefits, since they are directly observable and auditable. For example, marketing costs, measurement and evaluation costs, incentive costs, and administration costs all have established budgets. The exception to this is in estimating the incremental measure cost. This is a necessary input for the TRC, SCT, and PCT calculations.

For each of these tests, the appropriate cost to use is the cost of the energy efficiency device in excess of what the customer would otherwise have made. Therefore, the incremental measure costs must be evaluated with respect to a baseline. For example, a program that provides an incentive to a customer to upgrade to a high-efficiency refrigerator would use the premium of that refrigerator over the base model that would otherwise have been purchased.

Establishing the appropriate baseline depends on the type of measure. In cases where the customer would not have otherwise made a purchase, for example the early replacement of a working refrigerator, the appropriate baseline is zero expenditure.[10] In this case, the incremental cost is the full cost of the new high-efficiency unit. The four basic measure decision types are described in Table 4-4 along with different names often used for each decision type.

Table 4-4. Defining Customer Decision Types Targeted by Energy Efficiency Measures

Decision Type	Definition	Example
New New construction Lost opportunity	Encourages builders and developers to install energy efficiency measures that go above and beyond building standards at the time of construction	Utility offers certification or award to builder of new homes that meet or exceed targets for the efficient use of energy.
Replacement Failure replacement Natural replacement Replace on burnout	Customer is in the market for a new appliance because their existing appliance has worn out or otherwise needs replacing. Measure encourages customer to purchase and install efficient instead of standard appliance.	The utility provides a rebate that encourages the customer to purchase a more expensive, but more efficient and longer-lasting CFL bulb instead of an incandescent bulb.
Retrofit Early replacement	Customer's existing appliance is working with several years of useful life remaining. Measure encourages customer to replace and dispose of old appliance with a new, more efficient one.	The utility provides a rebate toward the purchase of a new, more efficient refrigerator upon the removal of an older, but still working refrigerator.
Retire	Customer is encouraged to remove, but not replace existing fixture.	The utility pays for the removal and disposal of older but still working "second" refrigerators (e.g., in the garage) that customer can conveniently do without.

Table 4-5 summarizes the calculation of measure costs for each of the decision types described above. In the table, "efficient device" refers to the equipment that replaces an existing, less-efficient piece of equipment. "Standard device" refers to the equipment that would be used in industry standard practice to replace an existing device. "Old device" refers to the existing equipment to be replaced.

Table 4-5. Defining Costs and Impacts of Energy Efficiency Measures

Type of Measure	Measure Cost ($/Unit)	Impact Measurement (kWh/Unit and kW/Unit)
New New construction Lost opportunity	Cost of efficient device **minus** cost of standard device *(Incremental)*	Consumption of standard device **minus** consumption of efficient device
Replacement Failure replacement Natural replacement Replace on burnout	Cost of efficient device **minus** cost of standard device *(Incremental)*	Consumption of standard device **minus** consumption of efficient device
Retrofit Early replacement *(Simple)*	Cost of efficient device **plus** installation costs *(Full)*	Consumption of old device **minus** consumption of efficient device
Retrofit Early replacement *(Advanced)**	Cost of efficient device **minus** cost of standard device **plus** remaining present value	*During remaining life of old device:* Consumption of old device **minus** consumption of efficient device *After remaining life of old device:* Consumption of standard device **minus** consumption of efficient device
Retire	Cost of removing old device	Consumption of old device

* The advanced retrofit case is essentially a combination of the simple retrofit treatment (for the time period during which the existing measure would have otherwise remained in service) and the failure replacement treatment for the years after the existing device would have been replaced. “Present Value” indicates that the early replacement costs should be discounted to reflect the time value of money associated with the installation of the efficient device compared to the installation of the standard device that would have occurred at a later date.

4.14 Notes

1 Installed capacity (ICAP), or unforced capacity (UCAP) in some markets, is an obligation of the electric utility (load serving entity, or LSE) to purchase sufficient capacity to maintain system reliability. The amount of ICAP an LSE must typically procure is equal to its forecasted peak load plus a reserve margin. Therefore, reduction in peak load due to energy efficiency reduces the ICAP obligation.

2 The ability to store natural gas, and to manage the gas system to serve peak demand periods by varying the pressure, reduces the share of gas costs associated with capacity relative to electricity.

[3] See <http://www.nwcouncil.org/energy/powerplan/5/Default.htm>.

[4] See <http://www.pacificorp.com/Navigation/Navigation23807.html>.

[5] See <http://www.nymex.com/ng_fut_csf.aspx> for current market prices at Henry Hub.

[6] See <http://www.nymex.com/cp_produc.aspx> for available basis swap products.

[7] The specifications may be developed by the utility or developed through a regulatory process with stakeholder input.

[8] Forecasts are available at <res://ieframe.dll/tabswelcome.htm>.
See <http://www.eia.doe.gov/oiaf/aeo/> for the latest edition of the Annual Energy Outlook.

[9] See <http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf> for a detailed description of the development of avoided costs in California.

[10] A simplifying assumption of zero as the baseline expenditure is often used, even though the equipment may have a limited remaining useful life and need replacement in a few years. Table 4-5 presents a more detailed calculation that can be used for early replacement programs.

5: Guidelines for Policy-Makers

A common misperception is that there is a "best" perspective for evaluating the cost-effectiveness of energy efficiency. On the contrary, no single test is more or less appropriate for a given jurisdiction. A useful analogy for the value of the five cost-effectiveness tests is the way doctors use multiple diagnostics to assess the overall health of a patient: each test reflects different aspects of the patient's health. This chapter describes how individual states use each of the five cost-effectiveness tests and why states might choose to emphasize some tests over others. Four hypothetical situations are presented to illustrate how states may emphasize particular tests in pursuit of specific policy goals.

5.1 Emphasizing Cost-Effectiveness Tests

Nationwide, the most common primary measurement of energy efficiency cost-effectiveness is the TRC, followed closely by the SCT. A positive TRC result indicates that the program will, over its lifetime, produce a net reduction in energy costs in the utility service territory. A positive SCT result indicates that the region (the utility, the state, or the United States) will be better off on the whole. Table 5-1 shows the distribution of primary cost-effectiveness tests used by state.

Table 5-1. Primary Cost-Effectiveness Test Used by Different States

PCT	PACT	RIM	TRC	SCT	Unspecified
	CT, TX, UT	FL	CA, MA, MO, NH, NM,	AZ, ME, MN, VT, WI	AR, CO, DC, DE, GA, HI, IA, ID, IL, IN, KS, KY, MD, MT, NC, ND, NJ, NV, OK, OR, PA, RI, SC, VA, WA, WY

Source: Regulatory Assistance Project (RAP) analysis.

Cost-effectiveness overall as analyzed by the TRC and SCT is not necessarily the only important aspect to evaluate when designing an energy efficiency portfolio. Even if benefits outweigh costs, some stakeholders can be net winners and others net losers. Therefore, many states also include one or more of the distributional tests to evaluate cost-effectiveness from individual vantage points. Using the results of the distribution tests, the energy efficiency measures and programs offered, their incentive levels, and other elements in the portfolio design can be balanced to provide a reasonable distribution of costs and benefits among stakeholders. Table 5-2 shows the distribution of cost-effectiveness tests used by states for either the primary or secondary consideration.

Table 5-2. Cost-Effectiveness Tests in Use by Different States as Primary or Secondary Consideration

PCT	PACT	RIM	TRC	SCT
AR, FL, GA, HI, IA, IN, MN, VA	AT, CA, CT, HI, IA, IN, MN, NO, NV, OR, UT, VA, TX	AR, DC, FL, GA, HI, IA, IN, KS, MN, NH, VA	AR, CA, CO, CT, DE, FL, GA, HI, IL, IN, KS, MA, MN, MO, MT, NH, NM, NY, UT, VA	AZ, CO, GA, HI, IA, IN, MW, MN, MT, NV, OR, VA, VT, WI

Source: Regulatory Assistance Project (RAP) analysis.

Using the PCT. The PCT provides two key pieces of information helpful in program design: at the measure level it provides some sense of the potential adoption rate, and it can help in setting the appropriate incentive level so as not to provide too small or too unnecessarily large an incentive. Setting the incentive levels is part art and part science. The goal is to get the most participation with the least cost. There is a balance between the PCT results with the PACT and RIM results. The higher the incentive, the higher the PCT benefit cost ratio and the lower the PACT and RIM benefit-cost ratio.

Using the PACT. The PACT provides an indication of how the energy efficiency program compares with supply-side investments. This is used to balance the incentive levels with the PCT. A poor PACT may also result from a low NTG, if, for example, a large number of customers would make the efficiency investment without the program. A poor PACT might also suggest that large incentives are required to induce sufficient adoption of a particular measure.

Using the RIM. The RIM as a primary consideration test is not as common as the other two distributional tests. If used, it is typically a secondary consideration test done on a portfolio basis to evaluate relative impacts of the overall energy efficiency program on rates. The results will provide a high-level understanding of the likely pressure on rates attributable to the energy efficiency portfolio. A RIM value below 1.0 can be acceptable if a state chooses to accept the rate effect in exchange for resource and other benefits. Efficiency measures with a RIM value below 1.0 can nevertheless represent the least-cost resource for a utility, depending on the time period and long-term fixed costs included in the avoided costs.

"You get what you measure"

When selecting cost-effectiveness tests to use as metrics for portfolio, remember the saying, "you get what you measure." If a single distributional test is used as a primary cost-effectiveness test, the portfolio may not balance benefits and costs between stakeholders. This is particularly true as utility incentive mechanisms are introduced that rely on cost-effectiveness results. Overall the results of all five cost tests provide a more comprehensive picture than any one test alone.

5.1.1 Use of Cost-Effectiveness Tests by State

Table 5-3 shows how states use cost-effectiveness tests. Many states use multiple cost-effectiveness tests to provide a more complete picture of energy efficiency cost-effectiveness. Eighteen states use two or more cost-effectiveness tests for some aspect of efficiency evaluation; four of those require all five tests. For example, Hawaii requires that all five tests be included in the analysis of supply and demand options in utility IRPs. Indiana uses all five tests to screen demand-side management (DSM) programs. Minnesota uses all five tests, but considers the SCT to be the most important. Many other states use two or three tests with different weights assigned to each test, or with separate tests being used for separate parts of the process. Several states have adopted formal and in some cases unique modifications to the standard forms of the tests.

The choice of tests and their applications reveal the priorities of the states and the perspectives of their regulatory commissions—the extent to which energy efficiency is considered a resource or the extent to which rates dominate policy implementation of energy efficiency. Some commissions like having a clear formula, using only one or two tests with threshold values to establish program scope.

The following are several examples of the types of decisions regulatory commissions have made regarding cost-effectiveness tests:

- In Colorado, a 2004 settlement with Xcel Energy required the TRC. A 2007 statute requires the use of a variation of the SCT that includes the utility's avoided costs, the valuation of avoided emissions, and NEBs as determined by the regulatory commission.

- Connecticut uses the PACT to screen individual DSM programs and the TRC to evaluate the total benefit of conservation and load management programs and to determine performance incentives.

- In the District of Columbia, the RIM is used for DSM programs. Those which have a cost-benefit ratio of 0.8 and 1.0 may be evaluated for other benefits, including long-term savings, market transformation, peak savings, and societal benefits.

- Iowa requires utilities to analyze DSM programs using the SCT, RIM, PACT, and PCT. According to statute, if the utility uses a test other than the SCT to determine the cost-effectiveness of energy efficiency programs and plans, it must describe and justify its use of the alternative test.

- In Montana, the SCT and TRC are used for the traditionally regulated utility that prepares IRPs. Neither test is required for the utility that conducts portfolio management, although statute specifies that the RIM should not be used.

- Utah requires that DSM programs meet the TRC and PACT in IRP. For supply and demand resources, the primary test is the PACT, calculated under a variety of scenarios; other tests may also be considered.

- California weighs the results of two of the cost-effectiveness tests, TRC and PACT, in this program screening process. California adopted a "Dual-Test" that uses the PACT to ensure that utilities are not over spending on incentives for programs that pass the TRC. The recently adopted shareholder incentive mechanisms use a weighting of two-thirds of the TRC portfolio net benefits result and one-third of the PACT portfolio net benefits result. An incentive is then paid based on the utility's combined results using this metric if the utility's portfolio of savings meets or exceeds the Commission's established energy savings goals.

Table 5-3. Use of Cost-Effectiveness Tests by States

State	Requires All	Primary Test	TRC	SCT	PCT	PACT	RIM	Other	Non Specific
AK									•
AL									•
AR			•		•	•	•		
AZ*		SCT		•					
CA		TRC	•			•			
CO			•	•					
CT		PACT	•			•			
DC							•	•	
DE*			•						
FL		RIM	•		•		•		
GA			•	•	•		•		
HI	•		•	•	•	•	•		
IA				•	•	•	•		
ID†			•	•	•	•			
IL			•						
IN	•		•	•	•	•	•		
KS*			•				•		
KY									•
LA									•
MA		TRC	•						
MD*									•
ME		SCT		•					
MI									•
MN	•	SCT	•	•	•	•	•		
MO		TRC	•			•			
MS									•
MT			•	•					
NC									•
ND									•
NE									•
NH		TRC	•				•		
NJ								•	
NM		TRC	•						
NV				•		•		•	
NY		TRC	•						
OH									•
OK									•
OR*				•		•			
PA									•
RI								•	
SC									•
SD									•
UT		PACT	•			•			
VA	•		•	•	•	•	•		
VT		SCT		•					
TN									•
TX		PACT				•			
WA								•	
WI		SCT		•					
WV									•
WY									•

* Proposed or not yet codified in statute/Commission Order.

† Allows any or all tests, though the RIM may not be used as primary or limiting cost-effectiveness test.

Source: Regulatory Assistance Project (RAP) analysis.

5.2 Picking Appropriate Costs, Benefits, and Methodology

With the cost-effectiveness tests determined, it is equally important to pick the appropriate costs, benefits, and methodology to align the energy efficiency portfolio with the overall policy goals and context for energy efficiency. The choices should ultimately reflect the situation of the utility and the state, its history in implementing energy efficiency, and other considerations. To provide some guidance, four hypothetical situations are considered along with several recommendations of possible approaches in each situation. Since the hypothetical situations do not consider any specific state, they should be viewed as a starting point for discussion and not specific policy recommendation for every context.

5.2.1 Situation A: Peak Load Growth and Upcoming Capital Investments

States or regions that are experiencing high peak load growth and associated large capital investments will want to ensure that the energy efficiency portfolio appropriately targets the peak and also provides higher benefits for peak load reduction that can be used to justify higher-cost energy efficiency such as air conditioner incentives or demand response.

One approach is to introduce time-specific avoided costs by hour, or by TOU. In addition, it will be important to initiate system planning studies that integrate supply- and demand-side planning so that the energy efficiency programs have the opportunity to defer or delay the supply-side capital investments. Unless the two processes are linked in some way, the energy efficiency program may be successful in reducing peak loads only to find that the capital projects also built. This could create a situation with too much capacity, and overspending on peak load reductions. In order to coordinate demand- and supply-side planning, it is important to start early. The lead time for large supply-side projects can be five or even 10 years. In addition, it is much easier to defer or eliminate the need for the project before the supply-side project proponents are deeply vested in its outcome.

5.2.2 Situation B: Utility Financial Problems

In a situation with a utility with financial problems, due to low load growth and/or a rate freeze, a different set of energy efficiency policies might be considered. Though the problem probably cannot be fixed with energy efficiency program design, there is no need to make it worse.

There are several approaches to encourage energy efficiency without straining the utility financially. One approach is to introduce decoupling or another automatic rate adjustment for reduced sales from energy efficiency to ensure recovery of fixed costs that have already been allowed in a prior rate case. A rate adjustment, whether tied to decoupling or not, may also help improve the utility financial situation.

If rate adjustments are not possible (whether through direct adjustment, decoupling, or another approach), another option may be to limit the impact of energy efficiency by specifying a minimum portfolio RIM. This will reduce the level of energy that can be saved but allow the portfolio to continue, perhaps with some lower-scoring programs placed on hiatus, while the financial issues of the utility are addressed.

5.2.3 Situation C: Targeting Load Pockets

If a utility has areas of growing load that require new transmission and/or generation investments to be made, energy efficiency may provide an alternative. In this case, it may be less expensive to use energy efficiency and demand response to reduce peak loads than to build new supply-side infrastructure. Using demand-side resources to alleviate a load pocket also has a lower impact on the environment.

In order to target the load pockets, the energy efficiency portfolio should include programs that specifically target peak load reduction in these areas. This can be done by increasing marketing of the same programs used service-territory-wide, or by developing a specific program to target peak load reductions in an area. Area- and time-specific costing should be introduced to estimate the value of the peak load reductions. Energy efficiency program managers should be given the authority to target certain areas. In this case, the equity of providing all of the same measures service-territory-wide may be overshadowed by value of a targeted program.

Targeting marketing and implementation is, by definition, discriminatory, but for legitimate, cost-based reasons. Targeting efficiency for areas with capacity constraints can be a prudent and least-cost means of accommodating load growth or meeting reliability criteria. While they may appear to favor certain customers, targeted efforts can provide sufficient incremental value to offer net benefits for all customers.

As in Situation A, it will be important in Situation B to initiate system planning studies that integrate supply- and demand-side planning so that the energy efficiency programs have the opportunity to defer or delay the supply-side load pocket mitigation measures.

5.2.4 Situation D: Aggressive Greenhouse Gas and RPS Policies

Many states are introducing the RPS and beginning to implement aggressive GHG policies. In these situations, policy-makers will need to emphasize energy savings. One approach to consider is to focus on the TRC or SCT, and not to use the RIM results. Policy-makers might also consider including a forecast of avoided CO_2 reductions in the avoided costs. In addition, including the avoided costs of the renewable energy or low-carbon resource that would otherwise be purchased (nuclear, renewables, carbon-capture, and sequestration) as the marginal resource can increase the avoided costs. This raises the quantity of efficiency measures and programs considered cost-effective. Finally, policy-makers will want to focus the cost-effectiveness tests at the portfolio level, rather than at the program or measure level.

6: Detailed Cost-Effectiveness Test Comparison—How Is Each Cost-Effectiveness Test Used?

This chapter describes the cost-effectiveness tests in order to provide greater understanding of calculation, results, and appropriate use of each test. Information is provided on the perspective, purpose, costs, benefits, and other considerations for each of the cost-effectiveness tests.

6.1 Participant Cost Test

The PCT examines the costs and benefits from the perspective of the customer installing the energy efficiency measure (homeowner, business, etc.). Costs include the incremental costs of purchasing and installing the efficient equipment, above the cost of standard equipment, that are borne by the customer. The benefits include bill savings realized to the customer through reduced energy consumption and the incentives received by the customer, including any applicable tax credits. Table 6-1 outlines the benefits and costs included in the PCT. In some cases the NPV of incremental operations and maintenance costs (or savings) may also be included.

Table 6-1. Benefits and Costs Included in the Participant Cost Test

Benefits and Costs from the Perspective of the Customer Installing the Measure	
Benefits	**Costs**
▪ Incentive payments ▪ Bill savings realized ▪ Applicable tax credits or incentives	▪ Incremental equipment costs ▪ Incremental installation costs

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

The primary use of the PCT is to assess the appeal of an energy efficiency measure to potential participants. The higher the PCT, the stronger the economic incentive to participate. The PCT functions similarly to a simple payback calculation, which determines how many years it takes to recover the costs of purchasing and installing a device through bill savings. A cost-effective measure will have a high PCT (above 1) and a low payback period. The PCT also provides useful information for designing appropriate customer incentive levels. A high incentive level will produce a high PCT benefit-cost ratio, but reduce the PACT and RIM results. This is because incentives given to customers are seen as “costs” to the utility. The PCT, PACT, and RIM register incentive payments in different ways based on their perspective. Utilities must balance the participant payback with the goal of also minimizing costs to the utility and ratepayers.

> A positive PCT (above 1) shows that energy efficiency provides net savings for the customer over the expected useful life of the efficiency measure.

6.1.1 Additional Considerations

As a measure of payback period or economic appeal, the PCT reflects an important aspect of potential participation rates. However, it is not a comprehensive evaluation of all the determinants that influence customer participation. For example, the PCT does not consider the level of marketing and outreach efforts (or expenditures) to promote the program, and marketing can be a major driver of adoption rates. In addition, new technologies may have high upfront costs, or steep learning curves, which yield limited adoption despite high PCT ratios. As a key example, energy-efficient CFLs generally reach a plateau despite high cost-effectiveness, indicating the importance of other factors in behavior besides bill savings.[1] This can be due to several factors including customer resistance and limited availability of premium features, such as the ability to dim.

Ideally the PCT will be performed using the marginal retail rate avoided by the customer. In practice the PCT is often performed using the utility's average rates for an applicable customer class. With tiered and TOU rates, the marginal rate paid by individual customers can vary significantly, which makes the use of marginal rate savings in the PCT somewhat more difficult. Furthermore, the impact of energy efficiency on a customer's peak load is difficult to predict, making changes in customer demand charges hard to estimate. In practice, the level of effort required to estimate the customers' actual savings given their consumption profile and applicable rate schedule is significant. Often utilities find it is not worth the effort at the program design or evaluation level, though it may be useful for individual customer audits. Thus the PCT gives an indication of the direct cost-based incentives for customers to participate in a given energy efficiency program.

6.2 Program Administrator Cost Test

The PACT examines the costs and benefits of the energy efficiency program from the perspective of the entity implementing the program (utility, government agency, nonprofit, or other third party). The costs included in the PACT include overhead and incentive costs. Overhead costs are administration, marketing, research and development, evaluation, and measurement and verification.[2] Incentive costs are payments made to the customers to offset purchase or installations costs (mentioned earlier in the PCT as benefits).[3] The benefits from the utility perspective are the savings derived from not delivering the energy to customers. Depending on the jurisdiction and type of utility, the "avoided costs" can include reduced wholesale electricity or natural gas purchases, generation costs, power plant construction, transmission and distribution facilities, ancillary service and system operating costs, and other components.[4] These elements are discussed in more detail in Chapter 4. The benefits and costs included in the PACT are summarized in Table 6-2.

Table 6-2. Benefits and Costs Included in the Program Administrator Test

Benefits and Costs to the Utility, Government Agency, or Third Party Implementing the Program	
Benefits	**Costs**
▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program overhead costs ▪ Utility/program administrator incentive costs ▪ Utility/program administrator installation costs

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

The PACT allows utilities to evaluate costs and benefits of energy efficiency programs (and/or demand response and distributed generation) on a comparable basis with supply-side investments. A positive PACT indicates that energy efficiency programs are lower-cost approaches to meeting load growth than wholesale energy purchases and new generation resources (including delivery and system costs). States with large needs for new supply resources may emphasize the PACT to build efficiency alternatives into procurement planning.[5]

> A positive PACT indicates that the total costs to save energy are less than the costs of the utility delivering the same power. A positive PACT also shows that customer average bills will eventually go down if efficiency is implemented.

6.2.1 Additional Considerations

The PACT provides an estimate of energy efficiency costs as a utility resource. Even the most comprehensive avoided cost estimates cannot capture all of the attributes of energy valued by the utility. In addition, the PACT only includes the program administrator costs and not those costs borne by customers. Therefore the PACT may not be seen as sufficiently comprehensive as a primary determinant of cost-effectiveness.

As with all of the cost-effectiveness tests, there are simplifications made in the calculation that should be understood when they are applied. For example, the PACT does not incorporate the different regulatory and financial treatment of utility investments in energy efficiency versus utility infrastructure. Therefore, while the PACT provides an estimate of energy efficiency as a resource, a positive PACT result does not imply that a utility will be better off financially. Finally, in order to get meaningful results on the PACT, care must be taken to estimate the actual resource savings to the utility from the energy efficiency program, including the timing and certainty of load reductions and the resulting impact on the utility supply costs.

Since the PACT includes the full savings to the utility but not the full costs of purchasing and installing the energy efficiency measures (which are paid by participants), the PACT is usually the easiest cost-effectiveness test to pass. In the SCE program featured in Appendix C, for example, the PACT ratio is 9.9—a higher value than that produced by any other cost-effectiveness test.

Jurisdictions seeking to increase efficiency implementation may choose to emphasize the PACT, which compares energy efficiency as a utility investment on par with other resources. Because the PACT includes only utility costs (and not customer contributions), the PACT is often the most permissive (and most positive) cost-effectiveness test.

6.3 Ratepayer Impact Measure

The RIM examines the impact of energy efficiency programs on utility rates. Unlike typical supply-side investments, energy efficiency programs reduce energy sales. Reduced energy sales can lower revenues and put upward pressure on retail rates as the remaining fixed costs are spread over fewer kWh. The costs included in the RIM are program overhead and incentive payments and the cost of lost revenues due to reduced sales.[6] The benefits included in the RIM are the avoided costs of energy saved through the efficiency measure (same as the PACT). Table 6-3 outlines the benefits and costs included in the RIM.

Table 6-3. Benefits and Costs Included in the Rate Impact Measure Test

Benefits and Costs to Ratepayers Overall; Would Rates Need to Increase?	
Benefits	**Costs**
▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program overhead costs ▪ Utility/program administrator incentive costs ▪ Utility/program administrator installation costs ▪ Lost revenue due to reduced energy bills

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Note: The PACT and the RIM use the same benefits.

The RIM also gives an indication of the distributional impacts of efficiency programs on non-participants. Participants may see net benefits (by lowering their bills through reduced energy consumption) while non-participating customers may experience rate increases due to the same programs. As the impacts on non-participating customers depend on many factors including the timing of adjustments to rates, the RIM is only an approximation of these impacts.

The RIM answers the question, “All other things being equal, what is the impact of the energy efficiency program on utility rates if they were to be adjusted to account for the program?” A negative RIM implies that rates would need to increase for the utility to achieve the same level of earnings in the short term.[7]

In the vast majority of cases, the RIM is negative since the retail rate is typically higher than the utility’s avoided cost. The RIM may be negative, even at the same time as average bills decrease (as evaluated using the PACT). Therefore, policy-makers have to decide whether to emphasize customer bills by using the PACT or customer rates by using the RIM.[8] The main reason cited for use of the RIM is to protect customer classes. Chapter 2 of the National Action Plan for Energy Efficiency Report (National Action Plan for Energy Efficiency, 2006) suggests effective ways to protect customer groups from rate increases in the rate design process that do not limit the use of energy efficiency. As described in Section 5.1 above, most jurisdictions do not choose the RIM as a primary test; many use it as a secondary consideration, if at all.[9]

6.3.1 Additional Considerations

It is sometimes observed that even least-cost utility investments made to maintain reliability often lead to a rate increase, yet the RIM has not been applied to these initiatives. One key consideration in assessing the RIM is that there is typically an allocation of fixed costs in the variable $/kWh rate. The fixed costs included in rates reflect the utility's existing revenue requirement and do not necessarily reflect future capital costs avoided through energy efficiency. Customers are often resistant to high fixed charges and lumpy utility investments are not always considered avoidable through efficiency savings that are realized gradually over time. In addition, avoided costs are often based on market prices, which tend to emphasize variable and short-term as opposed to long-term costs. Because many utilities have multiple standard, tiered, and TOU rate options, the actual marginal revenue loses to the utility can be difficult to estimate and not accurately captured when customer class average rates are used in the RIM calculation. Other considerations in the RIM, including the relationship to utility financial health over time and capacity-focused programs that yield higher RIM results, are discussed in further detail in Section 3.2.2 above.

> The RIM is the most restrictive of the five cost-effectiveness tests. When the utility's retail rates are higher than its avoided costs, the RIM will almost always be negative. Thus policy-makers may choose to emphasize the PACT and use the RIM as a secondary consideration for balancing the distribution of rate impacts.

6.4 Total Resource Cost Test

The TRC measures the net benefits of the energy efficiency program for the region as a whole. Costs included in the TRC are costs to purchase and install the energy efficiency measure and overhead costs of running the energy efficiency program. The benefits included are the avoided costs of energy (as with the PACT and the RIM). Table 6-4 outlines the benefits and costs in the TRC.

Table 6-4. Benefits and Costs Included in the Total Resource Cost Test

Benefits and Costs from the Perspective of All Utility Customers (Participants and Non-Participants) in the Utility Service Territory	
Benefits	**Costs**
▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (e.g., gas and water if utility is electric) ▪ Monetized environmental and non-energy benefits (see Section 4.9) ▪ Applicable tax credits (see text)	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or the utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

The primary purpose of the TRC is to evaluate the net benefits of energy efficiency measures to the region as a whole. Unlike the tests describe above, the TRC does not take the view of individual stakeholders. It does not include bill savings and incentive payments, as they yield an intra-regional transfer of zero ("benefits" to customers and "costs" to the utility that cancel each other on a regional level). For some utilities, the region considered may be limited strictly to its own service territory, ignoring benefits (and costs) to neighboring areas (a distribution-only utility may, for example, consider only the impacts to its distribution system). In other cases, the region is defined as the state as a whole, allowing the TRC to include benefits to other stakeholders (e.g., other utilities, water utilities, local communities). The TRC is useful for jurisdictions wishing to value energy efficiency as a resource not just for the utility, but for the entire region. Thus the TRC is often the primary test considered by those states seeking to include the benefits not just to the utility and its ratepayers, but to other constituents as well. The TRC may be considered the sum of the PCT and RIM, that is, the participant and non-participant cost-effectiveness tests. The TRC is also useful when energy efficiency might fall through the cracks taken from the perspective of individual stakeholders, but would yield benefits on a wider regional level.[10]

The inclusion of tax credits or incentives depends to some extent on the region considered. A municipal utility might consider state and federal tax incentives as a benefit from outside the region defined for the TRC. For a utility with a service territory that includes all or most of a particular state, state tax incentives would be an intra-regional transfer that is not included in the TRC. Some jurisdictions chose to consider all tax incentives as transfers excluded from the TRC. Generally speaking, tax incentives in the TRC should be treated consistently with the other resources to which energy efficiency may be compared.

> The TRC shows the net benefits of the energy efficiency program as a whole. It can be used to evaluate energy efficiency alongside other regional resources and communicate with other planning agencies and constituencies.

6.4.1 Additional Considerations

The TRC is similar to the PACT except that it considers the cost of the measure itself rather than the incentive paid by the utility. Because the incentives are less than the cost of the measure in most cases, the TRC is usually lower than the PACT. Therefore, the TRC will be a more restrictive test than the PACT and fewer measures will pass the TRC. Indeed, it is not unusual for a measure to fail the TRC while appearing economical both to the utility (PACT) and to the participant (PCT). Due to the incentives paid by the utility, the participant and the utility each pay only a portion of the full incremental cost of the measure, which is the cost to the region as a whole considered by the TRC.

The TRC says nothing about the distributional impacts of the costs of energy efficiency. To address distributional effects, many jurisdictions that use the TRC as the primary criteria also look at other cost-effectiveness tests. In situations where budgets constrain the amount of energy efficiency investment, a threshold value may be used. A lower threshold may be applied to programs that serve low-income or hard-to-reach groups, representing the distinct societal value of reaching these customer groups that is not reflected in the benefit-cost calculation.

> The TRC is more restrictive than the PACT because it includes the full cost of the energy efficiency measure and not just the incentives paid by the utility. As a result, a program may have a positive PACT and PCT but still not pass the TRC, because the utility and customer pay a fraction of the total measure cost that is included in the TRC.

6.5 Societal Cost Test

The SCT includes all of the costs and benefits of the TRC, but it also includes environmental and other non-energy benefits that are not currently valued by the market. The SCT may also include non-energy costs, such as reduced customer comfort levels. Table 6-5 outlines the benefits and costs in the SCT.

Table 6-5. Benefits and Costs Included in the Societal Cost Test

Benefits and Costs to All in the Service Territory, State, or Nation as a Whole	
Benefits	**Costs**
▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (e.g., gas and water if utility is electric) ▪ Non-monetized benefits (and costs) such as cleaner air or health impacts	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or the utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

In some cases, emissions costs are included in the market price used to determine avoided costs or are otherwise explicitly included in the TRC calculation (as in the SCE program example[11]). Emissions permit costs may already be included in the market price of electricity in some jurisdictions. In other jurisdictions, emissions are included in the SCT.[12]

As with the TRC, the inclusion of tax incentives varies by jurisdiction. Those using a broad definition of the society exclude tax incentives as a transfer. Others will include tax incentives originating from outside the immediate region considered.

> The SCT includes costs and benefits beyond the immediate region and those that are not monetized in the TRC, such as environmental benefits or GHG reductions.

6.5.1 Additional Considerations

Increasingly, benefits historically included only in the SCT are being included in the TRC in some jurisdictions. Including a cost for carbon dioxide (CO_2) emissions is a prime example. Though the future cost associated with CO_2 emissions remains highly uncertain and difficult to quantify, many utilities believe it is increasingly unlikely that the cost will be zero. In California, an approximate forecast is developed through a survey of available studies and literature. The IRPs of many utilities now include a risk or portfolio analysis to calculate an “expected” carbon value or to determine if the additional cost of a flexible portfolio is sufficiently robust under a range of possible futures.

Water savings are also being explicitly included in the TRC instead of the SCT. This helps promote measures such as front-loading clothes washers, which provide water savings that are of value to the region but beyond the direct purview of electric and natural gas utilities. There is also increasing interest in the West, where water supply is particularly energy intensive, in targeting the energy savings possible through water conservation.[13]

Some commissions eschew the SCT because factors not included in the TRC are found to be beyond their jurisdiction. Where this is the case, legislation would be needed to create or clarify the opportunity for commissions to consider the SCT. On the other hand, some states require that the societal test be considered when commissions evaluate energy efficiency programs. Some states adopt the California methodology, while other states adopt modified versions, adding or deleting costs or benefits consistent with state priorities. For example, Illinois uses a modified TRC defined in statute, in which gas savings are not included in electricity program evaluation. The New York State Energy Research and Development Authority (NYSERDA) calculates the TRC for three scenarios, adding non-energy benefits in Scenario 2 and macroeconomic benefits in Scenario 3.

> Energy efficiency is among the most cost-effective ways to reduce carbon emissions. The SCT is a useful test for jurisdictions seeking to implement or comply with GHG reduction goals. It can also be used to evaluate water savings.

6.6 Notes

[1] The PCT is only one of the determinants of customer participation, and bill savings are not the sole factor in a customer's decision to implement energy efficiency. Marketing and customer decision-making studies can be used to better understand the levels of customer participation more directly. See Golove and Eto, 1996; Schleich and Gruber, 2008.

[2] At a minimum, overhead costs generally include the salary (and benefits) of those employees directly involved in promoting energy efficiency. Some jurisdictions opt to include an allocation of fixed costs (i.e., office space) while others do not. To the extent they are applicable, research and development, marketing, evaluation, measurement, and verification and other costs may be included in the overall total, or reported individually as they are for the SCE example shown here. In cases where energy efficiency program costs are subject to special treatment (e.g., public funding and shareholder incentive mechanisms), detailed definitions of what may be included as an overhead cost are often required.

[3] The simplest example is a rebate paid to the customer for the purchase of an efficient appliance. However, as programs have grown in scope and complexity, so has the definition of an incentive. Two additional types of incentive are common: direct install costs and upstream payments. In many cases, the utility performs or pays for the labor and installation associated with an efficiency measure. Such payments, which are not for the equipment itself, but nevertheless reduce the cost to the customer, are considered direct install costs. Another approach, which is now common for CFL programs, calls for utilities to pay incentives directly to manufacturers and distributors. These upstream payments lower the retail cost of the product, though no rebate is paid directly to the customer.

[4] Avoided cost benefits vary according to the time and location of the energy savings. Chapter 5 describes various alternative approaches for estimating the benefits of energy efficiency.

[5] A specialized application of the PACT is in local IRPs. When a local area is at or near the system's capacity to serve its load, significant infrastructure investments are often required. If such investments can be deferred by reducing loads or load growth, there is additional value to the utility in installing energy efficiency and other distributed resources in that area. The additional savings that can be realized by the utility can justify increased customer incentives and marketing for a targeted efficiency program.

[6] The RIM, PACT, and PCT assess the impacts of the program from different, but interconnected stakeholder perspectives. The RIM includes the overhead and incentive payments included as costs in the PACT, but also includes revenue losses. The RIM recognizes the incentives and bill savings reported as benefits in the PCT, but the RIM reports these terms as costs (revenues losses).

[7] Even with a negative RIM result, efficiency may still be the most cost-effective means of meeting load growth. The full array of long-term investment options considered in utility resource planning cannot always be captured in the avoided costs used to evaluate energy efficiency.

[8] The exception to the predominance of the negative RIM result are utilities that can serve most of their loads with existing, low-cost generation, but are facing high costs to build new generation. In such cases, the avoided costs for energy efficiency may well be higher that the utility's retail rates.

[9] In practice, since utility rates are often frozen between rate-setting cycles and not continuously reset, the utility itself absorbs the losses (or gains) in its earnings until rates are adjusted. These adjustments can be made in several ways: the regular rate-setting cycle, a decoupling mechanism, or a revenue adjustment mechanism. In the long run, the reduced capital investments necessary as a result of energy efficiency will mitigate the rate increases. The National Action Plan for Energy Efficiency's Energy Efficiency Benefits Calculator can evaluate these impacts over time: <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/calculator.html>.This is discussed in more detail in Chapter 4.

[10] As an example, in areas of competitive procurement, distribution-only utilities may not see energy efficiency as an immediate interest because it may not yield significant T&D savings (and generation costs are not part of their purview). In such a case, the utility may not implement energy efficiency even if it is cost-effective from a regional perspective. As a result, regulators may ask the utility to focus on the TRC rather than the PACT when evaluating efficiency programs.

[11] California includes emissions permits and trading costs in the avoided cost calculations of the TRC.

[12] Tax incentives paid by the state or federal governments and financing costs are excluded from the SCT, because they are considered a zero net transfer. A wide range of NEBs have been considered and evaluated throughout the United States. For the participant and community, these NEBs resulted in increased comfort, improved air quality, greater convenience, and improved health and aesthetic benefits. For the utility, fewer shut-off notices or bill complaints occurred.

[13] The California Public Utilities Commission has approved pilot programs for investor-owned utilities to partner with water agencies and provide funding for water conservation incentives that provide energy savings (A.07-01-024).

Appendix A: National Action Plan for Energy Efficiency Leadership Group

Co-Chairs

Marsha Smith
Commissioner, Idaho Public Utilities Commission
President, National Association of Regulatory Utility Commissioners

James E. Rogers
Chairman, President, and C.E.O.
Duke Energy

Leadership Group

Barry Abramson
Senior Vice President
Servidyne Systems, LLC

Tracy Babbidge
Director, Air Planning
Connecticut Department of Environmental Protection

Angela Beehler
Senior Director, Energy Regulation/Legislation
Wal-Mart Stores, Inc.

Sheila Boeckman
Manager of Business Operations and Development
Waverly Light and Power

Bruce Braine
Vice President, Strategic Policy Analysis
American Electric Power

Jeff Burks
Director of Environmental Sustainability
PNM Resources

Kateri Callahan
President
Alliance to Save Energy

Jorge Carrasco
Superintendent
Seattle City Light

Lonnie Carter
President and C.E.O.
Santee Cooper

Sheryl Carter
Co-Director, Energy Program
Natural Resources Defense Council

Gary Connett
Director of Environmental Stewardship and Member Services
Great River Energy

Larry Downes
Chairman and C.E.O.
New Jersey Natural Gas (New Jersey Resources Corporation)

Roger Duncan
Deputy General Manager, Distributed Energy Services
Austin Energy

Angelo Esposito
Senior Vice President, Energy Services and Technology
New York Power Authority

Jeanne Fox
President
New Jersey Board of Public Utilities

Philip Giudice
Commissioner
Massachusetts Division of Energy Resources

Dian Grueneich
Commissioner
California Public Utilities Commission

Blair Hamilton
Policy Director
Vermont Energy Investment Corporation

Maureen Harris
Commissioner
New York State Public Service Commission

Mary Healey
Consumer Counsel for the State of Connecticut
Connecticut Consumer Counsel

Joe Hoagland
Vice President, Energy Efficiency and Demand Response
Tennessee Valley Authority

Sandy Hochstetter
Vice President, Strategic Affairs
Arkansas Electric Cooperative Corporation

Helen Howes
Vice President, Environment, Health and Safety
Exelon

Mary Kenkel
Consultant, Alliance One
Duke Energy

Ruth Kiselewich
Director, Conservation Programs
Baltimore Gas and Electric Company

Martin Kushler
Director, Utilities Program
American Council for an
Energy-Efficient Economy

Rick Leuthauser
Manager of Energy Efficiency
MidAmerican Energy Company

Harris McDowell
Senator
Delaware General Assembly

Ed Melendreras
Vice President, Sales and
Marketing
Entergy Corporation

Janine Migden-Ostrander
Consumers' Counsel
Office of the Ohio Consumers'
Counsel

Michael Moehn
Vice President, Corporate
Planning
Ameren Services

Fred Moore
Director, Manufacturing and
Technology, Energy
The Dow Chemical Company

Richard Morgan
Commissioner
District of Columbia Public
Service Commission

Clay Nesler
Vice President, Global Energy
and Sustainability
Johnson Controls, Inc.

Brock Nicholson
Deputy Director, Division of Air
Quality
North Carolina Department of
Environment and Natural
Resources

Jed Nosal
Chief, Office of Ratepayer
Advocacy
Massachusetts Office of
Attorney General Martha
Coakley

Pat Oshie
Commissioner
Washington Utilities and
Transportation Commission

John Perkins
Consumer Advocate
Iowa Office of Consumer
Advocate

Douglas Petitt
Vice President, Government
Affairs
Vectren Corporation

Phyllis Reha
Commissioner
Minnesota Public Utilities
Commission

Roland Risser
Director, Customer Energy
Efficiency
Pacific Gas and Electric

Gene Rodrigues
Director, Energy Efficiency
Southern California Edison

Wayne Rosa
Energy and Maintenance
Manager
Food Lion, LLC

Art Rosenfeld
Commissioner
California Energy Commission

Jan Schori
General Manager
Sacramento Municipal Utility
District

Ted Schultz
Vice President, Energy
Efficiency
Duke Energy

Larry Shirley
Division Director
North Carolina Energy Office

Paul Sotkiewicz
Senior Economist, Market
Services Division
PJM Interconnection

Jim Spiers
Senior Manager, Planning,
Rates, and Member Services
Tristate Generation and
Transmission Association, Inc.

Susan Story
President and C.E.O.
Gulf Power Company (Southern
Company)

Tim Stout
Vice President, Energy
Efficiency
National Grid

Deb Sundin
Director, Business Product
Marketing
Xcel Energy

Paul Suskie
Chairman
Arkansas Public Service
Commission

Dub Taylor
Director
Texas State Energy
Conservation Office

David Van Holde
Energy Manager, Department of
Natural Resources and Parks
King County, Washington

Brenna Walraven
Managing Director, National
Property Management
USAA Realty Company

J. Mack Wathen
Vice President, Regulatory
Affairs
Pepco Holdings, Inc.

Mike Weedall
Vice President, Energy Efficiency
Bonneville Power Administration

Michael Wehling
Strategic Planning and Research
Puget Sound Energy

Henry Yoshimura
Manager, Demand Response
ISO New England, Inc.

Dan Zaweski
Assistant Vice President of Energy Efficiency and Distributed Generation
Long Island Power Authority

Observers

Rex Boynton
President
North American Technician Excellence

James W. (Jay) Brew
Counsel
Steel Manufacturers Association

Roger Cooper
Executive Vice President, Policy and Planning
American Gas Association

Mark Crisson
President and C.E.O.
American Public Power Association

Dan Delurey
Executive Director
Demand Response Coordinating Committee

Reid Detchon
Executive Director
Energy Future Coalition

Ron Edelstein
Director, Regulatory and Government Relations
Gas Technology Institute

Sue Gander
Director, Environment, Energy, and Natural Resources Division
National Governors Association—Center for Best Practices

Jeff Genzer
General Counsel
National Association of State Energy Officials

Donald Gilligan
President
National Association of Energy Service Companies

Chuck Gray
Executive Director
National Association of Regulatory Utility Commissioners

Steve Hauser
President
GridWise Alliance

William Hederman
Member, IEEE-USA Energy Policy Committee
Institute of Electrical and Electronics Engineers

Marc Hoffman
Executive Director
Consortium for Energy Efficiency

John Holt
Senior Manager of Generation and Fuel
National Rural Electric Cooperative Association

Eric Hsieh
Manager of Government Relations
National Electrical Manufacturers Association

Lisa Jacobson
Executive Director
Business Council for Sustainable Energy

Kate Marks
Energy Program Manager
National Conference of State Legislatures

Meg Matt
President and C.E.O.
Association of Energy Services Professionals

Joseph Mattingly
Vice President, Secretary and General Counsel
Gas Appliance Manufacturers Association

Kenneth Mentzer
President and C.E.O.
North American Insulation Manufacturers Association

Ellen Petrill
Director, Public/Private Partnerships
Electric Power Research Institute

Steven Schiller
Board Director
Efficiency Valuation Organization

Jerry Schwartz
Senior Director
American Forest and Paper Association

Andrew Spahn
Executive Director
National Council on Electricity Policy

Rick Tempchin
Director, Retail Distribution Policy
Edison Electric Institute

Mark Wolfe
Executive Director
Energy Programs Consortium

Lisa Wood
Executive Director
Institute for Electric Efficiency

Facilitators

U.S. Department of Energy

U.S. Environmental Protection Agency

Appendix B: Glossary

Avoided costs: The forecasted economic benefits of energy savings. These are the costs that would have been spent if the energy efficiency had not been put in place.

Discount rate: A measure of the time value of money. The choice of discount rate can have a large impact on the cost-effectiveness results for energy efficiency. As each cost-effectiveness test compares the net present value of costs and benefits for a given stakeholder perspective, its computation requires a discount rate assumption.

Energy efficiency: The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. “Energy conservation” is a term that has also been used, but it has the connotation of doing without in order to save energy rather than using less energy to perform the same or better function.

Evaluation, measurement, and verification: The process of determining and documenting the results, benefits, and lessons learned from an energy efficiency program. The term “evaluation” refers to any real time and/or retrospective assessment of the performance and implementation of a program. “Measurement and verification” is a subset of evaluation that includes activities undertaken in the calculation of energy and demand savings from individual sites or projects.

Free rider: A program participant who would have implemented the program measure or practice in the absence of the program.

Impact evaluation: Used to determine the actual savings achieved by different programs and specific measures.

Integrated resource planning: A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, integrated resource planning includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost-effective energy efficiency and renewable energy alternatives.

Levelized cost: A constant value or payment that, if applied in each year of the analysis, would result in a net present value equivalent to the actual values or payments which change (usually increase) each year. Often used to represent, on a consistent basis, the cost of energy saved by various efficiency measures with different useful lives.

Marginal cost: The sum that has to be paid for the next increment of product or service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity.

Marginal emission rates: The emissions associated with the marginal generating unit in each hour of the day.

Market effects evaluation: Used to estimate a program's influence on encouraging future energy efficiency projects because of changes in the energy marketplace. All categories of programs can have market effects evaluations; however, these evaluations are primarily associated with market transformation programs that indirectly achieve impacts.

Market transformation: A reduction in market barriers resulting from a market intervention, as evidenced by a set of market effects, that lasts after the intervention has been withdrawn, reduced, or changed.

Measures: Installation of equipment, installation of subsystems or systems, or modification of equipment, subsystems, systems, or operations on the customer side of the meter, in order to improve energy efficiency.

Net-to-gross ratio: A key requirement for program-level evaluation, measurement, and verification. This ratio accounts for only those energy efficiency gains that are attributed to, and the direct result of, the energy efficiency program in question. It gives evaluators an estimate of savings that would have occurred even without program incentives.

Net present value: The value of a stream of cash flows converted to a single sum in a specific year, usually the first year of the analysis. It can also be thought of as the equivalent worth of all cash flows relative to a base point called the present.

Nominal: For dollars, "nominal" means the figure representing the actual number of dollars exchanged in each year, without accounting for the effect of inflation on the value or purchasing power. For interest or discount rates, "nominal" means that the rate includes the rate of inflation (real rate plus inflation rate equals the nominal rate).

Participant cost test: A cost-effectiveness test that measures the economic impact to the participating customer of adopting an energy efficiency measure.

Planning study: A study of energy efficiency potential used by demand-side planners within utilities to incorporate efficiency into an integrated resource planning process. The objective of a planning study is to identify energy efficiency opportunities that are cost-effective alternatives to supply-side resources in generation, transmission, or distribution.

Portfolio: Either (a) a collection of similar programs addressing the same market, technology, or mechanisms or (b) the set of all programs conducted by one organization.

Potential study: A study conducted to assess market baselines and energy efficiency savings potentials for different technologies and customer markets. Potential is typically defined in terms of technical, economic, achievable, and program potential.

Program administrators: Typically procure various types of energy efficiency services from contractors (e.g., consultants, vendors, engineering firms, architects, academic institutions, community-based organizations), as part of managing, implementing, and evaluating their portfolio of energy efficiency programs. Program administrators in many states are the utilities; in some states they are state energy agencies or third parties.

Program design potential study: Can be undertaken by a utility or third party for the purpose of developing specific measures for the energy efficiency portfolio.

Ratepayer impact measure: A cost-effectiveness test that measures the impact on utility operating margin and whether rates would have to increase to maintain the current levels of margin if a customer installed energy efficient measures.

Real: For dollars, “real” means that the dollars are expressed in a specific base year in order to provide a consistent means of comparison after accounting for inflation. For interest and discount rates, “real” means the inflation rate is not included (the nominal rate minus the inflation rate equals the real rate).

Societal cost test: A cost-effectiveness test that measures the net economic benefit to the utility service territory, state, or region, as measured by the total resource cost test, plus indirect benefits such as environmental benefits.

Time-of-use periods: Blocks of time defined by the relative cost of electricity during each block. Time-of-use periods are usually divided into three or four time blocks per 24-hour period (on-peak, mid-peak, off-peak, and sometimes super off-peak) and by seasons of the year (summer and winter).

Total resource cost test: A cost-effectiveness test that measures the net direct economic impact to the utility service territory, state, or region.

Utility/program administrator cost test: The program administrator cost test, also known as the utility cost test, is a cost-effectiveness test that measures the change in the amount the utility must collect from the customers every year to meet an earnings target—e.g., a change in revenue requirement. In a number of states, this test is referred to as the program administrator cost test. In those cases, the definition of the “utility” is expanded to program administrators (utility or third party).

Appendix C: Cost-Effectiveness Tables of Best Practice Programs

Southern California Edison Residential Incentive Program

SCE's Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances (not including HVAC). It is part of a coordinated statewide mass market efficiency program that coordinates marketing and outreach efforts. This program is used as the example in Section 3.1 to illustrate the calculation of each of the cost-effectiveness tests.

The values shown in Tables C-1, C-2 and C-3 are for the fourth quarter of 2006. Note that dollar benefits associated with emissions reductions are included in the forecasted avoided cost of energy, and are therefore not separately reported. The other category in this case includes direct implementation activity costs incurred by SCE that are over and above the cost of the efficiency measure. Direct installation costs paid by the utility that offset the cost of the measure are included under "program incentives."

Table C-1. SCE Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	898,548	
Marketing and outreach	$	559,503	
Rebate processing	$	1,044,539	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other	$	992,029	
Total program administration	**$**	**3,494,619**	**O**
Program incentives			
Rebates and incentives	$	1,269,393	
Direct installation costs	$	564,027	
Upstream payments	$	13,624,460	
Total incentives	**$**	**15,457,880**	**I**
Total program costs	**$**	**18,952,499**	
Net measure equipment and installation	**$**	**41,102,993**	**M**

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators, <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>.

Table C-2. SCE Program Benefits

Net Benefit Inputs				Var.
Resource savings	**Units**		**$**	
Energy (MWh)	2,795,290	$	187,904,906	
Peak demand (kW)	55,067		—	
Total electric	—	$	187,904,906	
Natural gas (MMBtu)	—		—	
Total resource savings		**$**	**187,904,906**	**S**
Participant bill savings	Electric	$	278,187,587	**B**
	Gas		—	
Monetized emission savings	**Tons**			
NO_x	421,633		—	
SO_x	—		—	
PM_{10}	203,065		—	
CO_2	1,576,374		—	
Total emissions		$	—	**E**
Non-monetized emissions (externalities)	**Tons**			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	**EXT**
Non-energy benefits		$	—	**NEB**

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators, <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>.

Table C-3. SCE Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	**Cost**	**Benefits**	**Ratio**
PCT	$ 41,102,993	$ 293,645,467	7.14
PAC	$ 18,952,499	$ 187,904,906	9.91
RIM	$ 297,140,086	$ 187,904,906	0.63
TRC	$ 44,597,612	$ 187,904,906	4.21
SCT	$ 44,597,612	$ 187,904,906	4.21
Costs and benefits included in each test			
PCT	= M	= B + I	
PAC	= O + I	= S	
RIM	= O + I + B	= S	
TRC	= O + M	= S + E	
SCT	= O + M	= S + E + EXT + NEB	
Estimated levelized costs and benefits			
Test	**Cost $/kWh**	**Benefits $/kWh**	
PCT	$0.026	$0.184	
PAC	$0.012	$0.117	
RIM	$0.186	$0.117	
TRC	$0.028	$0.117	
SCT	$0.028	$0.117	
Assumptions for levelized calculations			
Average measure life		14	
WACC		8.50%	
Discount factor for savings		57%	

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators, <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>.

Note: The discount factor uses an estimate of average measure life and the utility weighted average cost of capital to convert the net present value of costs and benefits into levelized annual figures. The levelized annual costs and benefits are then used to calculate costs and benefits on a $/kWh basis.

Avista Regular Income Programs

Avista is an electric and natural gas utility in the Northwest with headquarters in Spokane, Washington. The best practice program highlighted here represents the 2007 Regular Income Portfolio of electricity energy efficiency measures implemented by Avista. The numbers were obtained from the Triple-E Report produced by the Avista Demand-Side Management Team (Table 13E).

Avista reports gross results, which do not take free riders into account. Installation rates, persistence/failure and rebound ("snap-back" or "take-back") are taken into account in Avista's estimates of energy savings. Avista does consider NEBs when they are quantifiable and defensible, which are predominately benefits from the customer's perspective.

Avista contributed to projects saving over 53 million kWh and 1.5 million therms in 2007. The HVAC and lighting categories made up 81 percent of the electric savings while 97 percent of the natural gas savings were in the HVAC and Shell categories.

Avista incorporates quantifiable labor and operation and maintenance as non-energy benefits, which are included in the PCT, SCT, and TRC cost-effectiveness tests.

Table C-4. Avista Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	2,564,894	
Marketing and outreach		—	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other		—	
Total program administration	**$**	**2,564,894**	**O**
Program incentives			
Rebates and incentives	$	4,721,881	
Direct installation costs		—	
Upstream payments		—	
Total incentives	**$**	**4,721,881**	**I**
Total program costs	**$**	**7,286,775**	
Net measure equipment and installation	**$**	**16,478,257**	**M**

Source: Avista Triple-E Report , January 1, 2007—December 31, 2007.

Table C-5. Avista Program Benefits

Net Benefit Inputs				Var.
Resource savings	**Units**		**$**	
Energy (MWh)	—	$	30,813,091	
Peak demand (kW)	—		—	
Total electric	—	$	30,813,091	
Natural gas (MMBtu)	—	$	(355,426)	
Total resource savings		$	**30,457,665**	**S**
Participant bill savings	Electric	$	28,782,475	**B**
	Gas	$	(630,028)	
Monetized emission savings	**Tons**			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions		$	—	**E**
Non-monetized emissions (externalities)	**Tons**			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	**EXT**
Non-energy benefits		$	12,595,276	**NEB**

Source: Avista Triple-E Report , January 1, 2007—December 31, 2007.

Table C-6. Avista Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	**Cost**	**Benefits**	**Ratio**
PCT	$ 11,756,376	$ 40,747,723	3.47
PAC	$ 7,286,775	$ 30,457,665	4.18
RIM	$ 36,069,250	$ 30,813,091	0.85
TRC	$ 19,043,151	$ 43,052,941	2.26
SCT	$ 19,043,151	$ 43,052,941	2.26
Costs and benefits included in each test			
PCT	= M - I	= B + NEB	
PAC	= O + I	= S	
RIM	= O + I + B	= S	
TRC	= O + M	= S + E + NEB	
SCT	= O + M	= S + E + EXT + NEB	
Assumptions for levelized calculations			
Average measure life		14	
WACC		8.50%	
Discount factor for savings		57%	

Source: Avista Triple-E Report , January 1, 2007—December 31, 2007.

Puget Sound Energy Commercial/Industrial Retrofit Program

Puget Sound Energy's (PSE's) Commercial/Industrial Retrofit Program encourages customers to use electric and natural gas efficiently by installing cost- and energy-efficient equipment, adopting energy efficient designs, and using energy-efficient operations at their facilities. In addition, incentives are available for fuel switch measures that convert from electric to natural gas while serving the same end use. Applicable Commercial and Industrial Retrofit measure category headings include, but are not limited to: HVAC and refrigeration, controls, process efficiency improvements, lighting improvements, building thermal improvements, water heating improvements, and building commissioning.

Customers provide PSE with project costs and estimated savings. Customers assume full responsibility for selecting and contracting with third-party service providers. Projects must be approved for funding prior to installation/implementation. Maximum grants for hardware changes are based on PSE's cost-effectiveness standard. Grants for projects are made available as a percentage of the measure cost. Electric and gas measures may receive incentive grants up to 70 percent of the measure cost where the grant incentive does not exceed the cost-effectiveness standard minus program administration costs. Measures exceeding the cost-effectiveness standard will receive grants that are on a declining scale and will be less than 70 percent of the measure cost. Electric and gas measures that have a simple payback of less than a year are not eligible for a grant incentive.

Unlike the other programs presented in this document, PSE shows a positive RIM. A positive RIM is possible in the Pacific Northwest because of the allocation of low-cost hydro generation from the Bonniville Power Administration to municipal utilities. In some cases the marginal cost of avoided generation is determined by higher-cost thermal generation and is higher than the utility's average retail rate.

Table C-7. PSE Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	2,745,048	
Marketing and outreach		—	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other		—	
Total program administration	**$**	**2,745,048**	**O**
Program incentives			
Rebates and incentives	$	9,914,463	
Direct installation costs		—	
Upstream payments		—	
Total incentives	**$**	**9,914,463**	**I**
Total program costs	**$**	**12,659,511**	
Net measure equipment and installation	**$**	**25,103,588***	**M**

Source: Data provided by Laura Feinstein at PSE.

* Total value

Table C-8. PSE Program Benefits

Net Benefit Inputs				Var.
Resource savings	**Units**		**$**	
Energy (MWh)	775,469	$	50,465,421	
Peak demand (kW)	—		—	
Total electric	—	$	50,465,421	
Natural gas (MMBtu)	661,480	$	2,575,451	
Total resource savings		**$**	**53,040,873**	**S**
Participant bill savings	Electric	$	33,297,727	**B**
	Gas		—	
Monetized emission savings	**Tons**			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	1,576,374		—	
Total emissions		$	—	**E**
Non-monetized emissions (externalities)	**Tons**			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	**EXT**
Non-energy benefits		$	—	**NEB**

Source: Data provided by Laura Feinstein at PSE.

Table C-9. PSE Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	**Cost**	**Benefits**	**Ratio**
PCT	$ 25,103,588	$ 43,212,190	1.72
PAC	$ 12,659,511	$ 53,040,873	4.19
RIM	$ 45,957,238	$ 53,040,873	1.15
TRC	$ 27,848,636	$ 53,040,873	1.90
SCT	$ 27,848,636	$ 53,040,873	1.90
Costs and benefits included in each test			
PCT	= M	= B + I	
PAC	= O + I	= S	
RIM	= O + I + B	= S	
TRC	= O + M	= S + E	
SCT	= O + M	= S + E + EXT + NEB	
Estimated levelized costs and benefits			
Test	**Cost $/kWh**	**Benefits $/kWh**	
PCT	$0.05	$0.09	
PAC	$0.03	$0.11	
RIM	$0.10	$0.11	
TRC	$0.06	$0.11	
SCT	$0.06	$0.11	
Test	**Cost $/Therm**	**Benefits $/Therm**	
PCT	$3.22	$5.54	
PAC	$1.62	$6.80	
RIM	$5.90	$6.80	
TRC	$3.57	$6.80	
SCT	$3.57	$6.80	
Assumptions for levelized calculations			
Average measure life		14	
WACC		8.50%	
Discount factor for savings		57%	

Source: Data provided by Laura Feinstein at PSE.

National Grid MassSAVE Program

The Massachusetts MassSAVE program is a residential conservation program targeting electricity and natural gas savings. The data shown in the tables that follow are taken from the National Grid 2006 Energy Efficiency Annual Report, submitted to the Massachusettes Department of Energy Resources and Department of Public Utilities in August 2007.

In the residential sector, there are diminishing energy savings available from single-measure incentive programs, in part due to federal appliance and lighting standards, as well as rapid progress in increasing the market penetration of CFLs relative to incandescent lighting. As a result, more utilities are seeking to develop program models that tackle harder-to reach opportunities and offer more comprehensive savings. National Grid's Home Performance with ENERGY STAR is one such program model. This program offers comprehensive whole-house improvements (insulation, air sealing, duct sealing, and HVAC improvements) for homeowners. Customers receive in-home services, step-by-step guidance, incentives for energy measures, quality installations and inspections, and low-interest financing.

Since contractors that deliver home performance services are in short supply in most markets, an infrastructure building phase is typically needed. During the initial two- to three-year startup phase, program costs may be high relative to energy savings. However, as contracting services increase over time, energy savings tend to increase dramatically. Limiting cost-effectiveness tests to three-year program cycles or less may inadvertently limit the development of these long-term, comprehensive program models. National Grid was able to reduce administrative costs associated with contractor recruitment, training, and quality assurance by limiting contractor participation in program startup and by requiring participating contractors to directly install some measures.

Comprehensive, whole-building program models such as Home Performance with ENERGY STAR may face a number of additional challenges using commonly employed practice for calculating cost-effectiveness. For example, installing air sealing and insulation reduce heating and cooling loads, which reduces the savings associated with installing efficient HVAC equipment (interactive effects; see Section 3.2.1). However, reduced heating and cooling loads can also provide opportunities for downsizing heating and cooling systems, which are not captured by the cost-effectiveness tests. Furthermore, whole-house improvements provide a variety of non-energy benefits (Section 4.9) that can be difficult to quantify and are often not included as benefits in the cost-effectiveness tests.

More information can be found online at <http://www.masssave.com/customers/>.

Table C-10. National Grid Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	760,324	
Marketing and outreach	$	296,628	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification	$	134,077	
Shareholder incentive		—	
Other		—	
Total program administration	**$**	**1,191,029**	**O**
Program incentives			
Rebates and incentives	$	3,507,691	
Direct installation costs		—	
Upstream payments		—	
Total incentives	**$**	**3,507,691**	**I**
Total program costs	**$**	**4,698,720**	
Net measure equipment and installation	**$**	**2,452,985**	**M**

Source: Data provided by Lynn Ross at National Grid.

Table C-11. National Grid Program Benefits

Net Benefit Inputs				Var.
Resource Savings	**Units**		**$**	
Energy (MWh)	46,385	$	2,550,000	
Peak demand (kW)	6,921		3,328,000	
Total electric	—	$	5,878,000	
Natural gas (MMBtu)	655,547		6,506,048	
Total resource savings		**$**	**12,384,048**	**S**
Participant bill savings	Electric	$	679,800	**B**
	Gas		—	
Monetized emission savings	**Tons**			
NO_x	7		—	
SO_x	19		—	
PM_{10}	—		—	
CO_2	1,576,374		—	
Total emissions		$	—	**E**
Non-monetized emissions (externalities)	**Tons**			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	**EXT**
Non-energy benefits		$	155,601	**NEB**

Source: Data provided by Lynn Ross at National Grid.

Table C-12. National Grid Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	**Cost**	**Benefits**	**Ratio**
PCT	$ 2,452,985	$ 4,187,491	1.71
PAC	$ 4,698,720	$ 12,384,048	2.64
RIM	$ 5,378,520	$ 12,384,048	2.30
TRC	$ 7,151,705	$ 12,384,048	1.73
SCT	$ 7,151,705	$ 12,539,649	1.75
Costs and benefits included in each test			
PCT	= M	= B + I	
PAC	= O + I	= S	
RIM	= O + I + B	= S	
TRC	= O + M	= S + E	
SCT	= O + M	= S + E + EXT + NEB	
Estimated levelized costs and benefits			
Test	**Cost $/kWh**	**Benefits $/kWh**	
PCT	$0.04	$0.06	
PAC	$0.07	$0.18	
RIM	$0.08	$0.18	
TRC	$0.10	$0.18	
SCT	$0.10	$0.18	
Test	**Cost $/Therm**	**Benefits $/Therm**	
PCT	$2.79	$4.76	
PAC	$5.34	$14.08	
RIM	$6.11	$14.08	
TRC	$8.13	$14.08	
SCT	$8.13	$14.26	
Assumptions for levelized calculations			
Average measure life		8	
WACC		8.50%	
Discount factor for savings		70%	

Source: Data provided by Lynn Ross at National Grid.

Appendix D: References

Erickson, J., B. Ward, and J. Mapp (2004). *Peak Demand Reduction vs. Emissions Savings: When Does It Pay to Chase Emissions?* ACEEE Summer Study paper.

Golove, W.H., and J.H. Eto (1996). *Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy Efficiency*. Lawrence Berkeley National Laboratory LBL-38059.

Mahone, A., J. Moore, J. Williams, and C.K. Woo (2008). *Energy Efficiency's Impact on California's Renewable Energy Development*. 2008 ACEEE Summer Study on Energy Efficiency in Buildings, August 17–22, 2008, Pacific Grove, CA.

National Action Plan for Energy Efficiency (2006). *The National Action Plan for Energy Efficiency*. <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/action-plan.html>

National Action Plan for Energy Efficiency (2007a). *Aligning Utility Incentives with Energy Efficiency Investment*. Prepared by Val R. Jensen, ICF International. <http://www.epa.gov/eeactionplan>

National Action Plan for Energy Efficiency (2007b). *Guide to Resource Planning with Energy Efficiency*. Prepared by Snuller Price et al., Energy and Environmental Economics, Inc. <http://www.epa.gov/eeactionplan>

National Action Plan for Energy Efficiency (2007c). *Model Energy Efficiency Program Impact Evaluation Guide*. Prepared by Steven R. Schiller, Schiller Consulting, Inc. <http://www.epa.gov/eeactionplan>

National Action Plan for Energy Efficiency (2008). *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change*. <http://www.epa.gov/eeactionplan>

Schleich, J., and E. Gruber (2008). Beyond case studies: Barriers to energy efficiency in commerce and the services sector. *Energy Economics* 30: 449-464. <http://eetd.lbl.gov/ea/emp/reports/38059.pdf>

BRITISH COLUMBIA
The Best Place on Earth

Ministry of Energy and Mines

Overview of DSM Regulation

DSM Regulation Workshop
February 28, 2012
Surrey, BC

Andrew Pape-Salmon, P.Eng., MRM
Director, Energy Efficiency Branch

BRITISH COLUMBIA
The Best Place on Earth
Ministry of Energy and Mines

Overview

- Purpose of DSM Regulation
- Key Provisions in 2008 regulation
- Adequacy
- Cost Effectiveness (pre-2011) - TRC
- Enhanced Cost Effectiveness (2011) - MTRC
  - Avoided cost of energy
  - Non-energy benefits
- Codes and Standards
- Specified DSM
- Financial Impact Cap
- Utility Cost Test

Purpose of DSM Regulation

- Defines how the BCUC evaluates the cost-effectiveness of demand-side measures
- Balances BCUC discretion to independently evaluate financial prudency of DSM portfolios against certainty of DSM outcomes
- Defines components that must be included in a DSM portfolio (adequacy)
- Authority in the *Utilities Commission Act,* s.125.1(4)
- First entered-into-force in 2008; amended in 2011

British Columbia
The Best Place on Earth
Ministry of Energy and Mines

Key Provisions in 2008

- Four types of measures required (adequacy)
- DSM portfolios can be evaluated at an individual, multiple program or portfolio-wide level
- Low-income programs evaluated with 130% benefits
- “Specified” measures evaluated at portfolio level
- Bulk purchasers value electricity at BCH supply cost
- Limited codes and standards attribution
- DSM cannot be rejected on basis of Rate Impact Measures (RIM) / non-participant test

Adequacy

- Requirement for utilities to have programs for
  - low-income households,
  - rental accommodations,
  - education programs for schools in utility service area,
  - post-secondary institutions
- Section 3

Cost Effectiveness (pre-2011) - TRC

- Discretion of utility / BCUC on which test
- Total Resource Cost (TRC) test is predominant method (although not required in regulation)
  - Ratio of benefits to costs
  - A value >= 1.0 is "cost effective"
  - Benefits include energy savings (multi-fuel)
  - Avoided supply cost of utility (except bulk purchaser)
  - Typically does not include "non-energy" financial benefits
  - Costs include utility admin and incentive costs, capital costs (net of incentive) and O&M

Enhanced Cost Effectiveness - MTRC

- The regulation now outlines a modified Total Resource Cost (MTRC) method
- Expands benefits to include non-energy benefits
- Provides a consistent avoided supply cost that reflects a zero greenhouse gas emitting source
- Under these provisions, both the MTRC and traditional cost-benefit test (e.g., TRC) must be calculated for the purpose of applying a cap on MTRC approved expenditures

MTRC - Avoided cost of energy

- Must use a zero-emission clean energy alternative (ZEEA) for all DSM avoided costs
- Electricity
  - – BC Hydro (BCH) long-run marginal cost of clean or renewable electricity resources (LRMC-CRR)
  - – FortisBC Inc. LRMC-CRR
- Natural Gas
  - – 50% of BCH LRMC-CRR
  - – Applies only to DSM that reduces GHGs

MTRC - Avoided cost of energy

- Example A:
- *A measure reduces natural gas demand by 10 GJ for one year. If in that year, BC Hydro's long-run marginal cost of acquiring clean or renewable BC electricity is $129/MWh (purely fictional example), the avoided cost of natural gas is calculated in the MTRC as:*
- *10 GJ * $129/MWh * 1 MWh/3.6 GJ * 0.5*
- *= $179 benefit*

BRITISH COLUMBIA
The Best Place on Earth
Ministry of Energy and Mines

MTRC - Avoided cost of energy

- Example B:
- *A gas utility proposes a program to replace gas boilers with geoexchange heating systems. In its first year it will reduce natural gas use by 1,000 GJ and increase electricity use by 60 MWh.*
- *If the gas utility's standard TRC uses an electricity tier 2 cost of $96/MWh, and if BC Hydro's long-run marginal cost of acquiring clean or renewable BC electricity is $129/MWh, the avoided cost of energy for the program's first year would be calculated in the MTRC as:*
- *(1,000 GJ * $129/MWh * 1 MWh/3.6 GJ * 0.5) – (60 MWh * $96/MWh) =$17,917 - $5,760 =$12,157*

MTRC - Non-energy benefits

- Non-energy benefits (NEBs) include attributes valued by consumers/investors, reflected by willingness to pay, e.g.,:
  - front loading clothes washers that use less soap and reduce wear and tear on clothes
  - reduced noise transmission through ENERGY STAR® windows and UV light damage to interior
  - Improved comfort and healthfulness of buildings with heat recovery ventilators

British Columbia
The Best Place on Earth
Ministry of Energy and Mines

MTRC - Non-energy benefits

- MTRC includes a 15% adder to all energy benefits as a proxy for NEBs (except low-income that has a 30% adder)
- Hierarchy of application
  - Customized calculation of NEBs by utilities (can exceed 15%)
  - All measures have a 15% NEB adder
  - Combination of NEB adders such that portfolio-wide NEB = 15%

MTRC - Non-energy benefits

Example D – Quantified NEBs are less than 15% of pre-NEB portfolio benefits

In this example, there are quantified NEBs for program A and D which on their own do not increase portfolio benefits by 15% or more. Remaining measures are assigned a deemed NEB adder of 9% which results in a 15% increase in portfolio benefits.

Measure	Benefits	Non-Energy Benefits	% Increase	New Total Benefits
Program A	\$100,000	\$20,000	20%	\$120,000
Program B	\$50,000	\$4,569	9%	\$54,569
Program C	\$75,000	\$6,853	9%	\$81,854
Program D	\$10,000	\$5,000	50%	\$15,001
Program E	\$20,000	\$1,828	9%	\$21,828
TOTAL	**\$255,000**	**\$38,250.00**	**15%**	**\$293,250**

MTRC - Non-energy benefits

Example E – Quantified NEBs exceed 15% of pre-NEB portfolio benefits

In this example, there are quantified NEBs for program A and D which on their own increase portfolio benefits by 15% or more. As a result, remaining programs are not given a deemed NEB adder.

Measure	Benefits	Non-Energy Benefits	% Increase	New Total Benefits
Program A	$100,000	$30,000	30%	$130,000
Program B	$50,000	-	-	$50,000
Program C	$75,000	-	-	$75,000
Program D	$10,000	$10,000	100%	$20,001
Program E	$20,000	-	-	$20,000
TOTAL	**$255,000**	**$40,000**	**16%**	**$295,000**

Codes and Standards

- Includes
  - Regulated items – product or system that uses energy or controls or affects energy use, building design, building site design, building site selection plan or community design
  - *Energy Efficiency Act* proposals noting DSM regulation
  - NRCan EE Act proposals pre-published in *Canada Gazette*
  - BC Building Code proposal, noting DSM regulation
  - Bylaw of local authority promoting energy efficiency
  - First Nation law promoting energy efficiency

Codes and Standards

- BCUC may increase benefit of a DSM by a proportion of avoided capacity and energy costs that (in BCUC opinion) will result from application of standard
- Example:
  – Government publishes proposed residential boiler standard for fall 2013 in a Regulatory Impact Statement (RIS) in 2012 and notes the DSM regulation
  – DSM is an expanded incentive for ENERGY STAR boilers for new construction through to proposed effective date
  – BCUC can approve a proportion of the post –regulatory savings to be included in pre-regulatory DSM benefits

BRITISH COLUMBIA
The Best Place on Earth
Ministry of Energy and Mines

Specified Demand-Side Measures

- "Specified" measures evaluated at portfolio level
  - School education programs
  - Post-secondary education programs
  - Energy efficiency training (trades, professionals, etc)
  - Community engagement programs
  - Technology innovation programs
  - (new) financial and other resources for C&S to:
    - Standards-making body (e.g., CSA) for development of standards
    - Government or regulatory body to support development of, or compliance with a specified standard or a measure
- Public awareness evaluated at portfolio level

British Columbia — The Best Place on Earth | Ministry of Energy and Mines

Financial Impact Cap

- Limits costs of DSM that passes under MTRC to:
  - 33% of total portfolio (natural gas) or,
  - 10% of portfolio (electricity)
- Applies only to DSM that:
  - Fails TRC (or other traditional test),
  - Passes MTRC
- Does not include:
  - DSM that fails the MTRC,
  - Specific DSM and public awareness,
  - Low-income that does not use ZEEA to pass

Ministry of Energy and Mines

Financial Impact Cap

- Example G:

A gas utility proposes an expenditure portfolio of $3.1 million:

Measure	**TRC without 4(1.1)**	**TRC with 4(1.1)**	**Subject to cap? (reason)**	**Expenditure $ (%)**
Efficient fireplace program	1.2	1.6	No (passes both TRCs)	$500,000 (16%)
Residential boiler program	0.8	1.2	**Yes** (fails TRC)	$500,000 **(16%)**
Commercial boiler program	1.0	1.4	No (passes both TRCs)	$500,000 (16%)
Leaky condo retrofit pilot	0.5	0.8	No (fails both TRCs)	$300,000 (10%)
Furnace program	0.6	1.0	**Yes** (fails TRC)	$250,000 **(8%)**
Low income program with ZEEA	0.8	1.1	**Yes** (fails TRC)	$250,000 **(8%)**
Low income program without ZEEA (with s4(2) 30% adder)	1.1	1.6	No (passes both TRCs)	$500,000 (16%)
Homebuilder training	-	-	No (specified DSM)	$200,000 (6%)
Community conservation campaign	-	-	No (effective public awareness program)	$100,000 (3%)
TOTAL				**$3,100,000 (100%)**

British Columbia
The Best Place on Earth
Ministry of Energy and Mines

Utility Cost Test

- Utility Cost Test (UCT) can be used to determine cost effectiveness
- UCT can be compared directly against new supply
- The following DSM is exempt from UCT:
  - Specified DSM
  - Public awareness
  - Low-income
  - Codes and standards attribution (without ZEEA, NEBs)

Ministry of Energy and Mines

Questions or Comments?

- Andrew Pape-Salmon, P.Eng., MRM
  Director – Energy Efficiency Branch
  BC Ministry of Energy and Mines
  Email: andrew.papesalmon@gov.bc.ca
  Web: http://www.empr.gov.bc.ca/EEC/Strategy/Pages/default.aspx

Attachment 218.3

CLEAN POWER CALL REQUEST FOR PROPOSALS

Report on the RFP Process

August 3, 2010

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA
The Best Place on Earth

PURPOSE OF REPORT

British Columbia Hydro and Power Authority (BC Hydro) prepared this document (the Report) to explain the rationale for awarding 25 Electricity Purchase Agreements (EPAs) with a volume of 3,266 Gigawatt hours (GWh) per year of firm energy pursuant to the Clean Power Call Request for Proposals (RFP).

A Note on Price Disclosure

BC Hydro believes in the importance of transparency. However, BC Hydro must at the same time treat as confidential any information which if disclosed could reasonably be expected to result in significant harm or prejudice to the proponent's competitive position or undue material financial loss or gain to a person. In this Report BC Hydro has provided levelized plant gate prices and levelized adjusted Firm Energy Prices (FEPs) for the awarded EPAs, as well as the final bid prices in dollars per megawatt hour ($/MWh) for the awarded EPAs. This information is provided without attribution.

CONTENTS

1. EXECUTIVE SUMMARY

To ensure that there is sufficient clean, renewable energy to meet forecast electricity demand, BC Hydro issued the Clean Power Call on June 11, 2008. The Clean Power Call was a result of comprehensive planning, design and engagement to ensure that the terms of the call resulted in the acquisition of cost-effective new supply for BC Hydro's ratepayers.

In November 2008, BC Hydro received 68 proposals from 43 proponents, representing more than 17,000 GWh per year of energy. Ultimately, BC Hydro selected 27 projects for the award of 25 EPAs (three projects were combined into a single EPA), representing 3,266 GWh per year of firm energy and 1,168 megawatts (MW) of capacity. The 27 projects included 19 run-of-river projects, six wind projects, one storage hydro project and one waste heat project.

Determining the Need for the Clean Power Call

In its 2008 Long Term Acquisition Plan (LTAP), BC Hydro identified the need for a Clean Power Call with a proposed pre-attrition target of 5,000 GWh/year of firm energy. This target was subsequently lowered but BC Hydro reserved the right to acquire up to 5,000 GWh/year if the EPAs proved to be cost-effective. As evidenced by the final level of EPA awards, BC Hydro has chosen to acquire less than the initial Clean Power Call target volume on the basis that the non-successful projects were viewed as not being cost-effective or having other eligibility or risk-related problems.

At the time of completing its evaluation of Clean Power Call proposals, BC Hydro updated its load forecasts and reassessed its energy load/resource balance. Based on existing and committed resources, BC Hydro determined that there would be a shortfall of 600 GWh in F2013, which would grow to 4,100 GWh in F2017. Notwithstanding the energy expected to be acquired from BC Hydro's current acquisition processes (the Bioenergy Phase 2 Call and the Integrated Power Offer), there is still a projected energy shortfall of 2,300 GWh/year beginning in F2017. The 3,266 GWh/year being purchased under the Clean Power Call equates to 2,286 GWh/year on a post-attrition basis (using an assumed 30% attrition factor) and will effectively fill the projected F2017 energy gap, thereby resulting in self-sufficiency by the prescribed 2016 date.

Designing the Call and Involving Stakeholders and First Nations in the Process

The Clean Power Call utilized an RFP process to allow more flexibility for negotiating price and cost-effective contract terms and conditions. This was done, in part, to help address the needs of larger and more complex projects. The RFP allowed proponents to propose variations to BC Hydro's preferred EPA terms and conditions.

Prior to launching the Clean Power Call, BC Hydro sought input from independent power producers (IPPs), other stakeholders and First Nations on the call and provided several opportunities for education and discussion on call design, proposed terms and conditions and process. Early Clean Power Call engagement efforts included dialogue sessions, workshops and an information session on BC Hydro's system needs. This provided an opportunity for stakeholders and First Nations to provide input on how system needs could be met through future calls. Following the release of the draft terms of the Clean Power Call, BC Hydro held an information session to improve understanding of the draft documents, encourage discussion and facilitate informed feedback. BC Hydro received over 40 submissions with approximately 600 written comments on the draft terms. Many submissions indicated a need for further discussion of residual rights, which refers to transfer of ownership of assets at the contract's end or a contract extension. As a result, BC Hydro held two additional dialogue sessions. Input received through the engagement process informed the design of the Clean Power Call and resulted in several changes to the terms and conditions of the call.

BC Hydro held two further sessions following the launch of the Clean Power Call. The first, held shortly after the call's issuance, provided potential participants with an overview of the revised RFP and EPA terms, the registration process and the timeline for the Clean Power Call, along with an overview of the transmission and distribution interconnection process. The second, held prior to the proposal submission deadline, provided registered proponents with the opportunity to review proposal requirements, EPA formulae and post-proposal submission processes.

Evaluating and Selecting Proposals

The RFP required that proponents and projects meet specific eligibility criteria. One of the main prerequisites was that all project output must qualify as clean or renewable electricity in accordance with the guidelines entitled "*British Columbia's Clean or Renewable Electricity Definitions*" published by the B.C. Ministry of Energy, Mines and Petroleum Resources and that a minimum of 25 GWh/year of seasonally or hourly firm energy be delivered. Other key RFP terms included providing proponents with a choice for their guaranteed Commercial Operation Date (between November 1, 2010 and November 1, 2016) and their preferred EPA term (between 15 to 40 years).

Proponents were strongly encouraged to submit proposals that conformed to the preferred terms and conditions provided in the Specimen EPA and to limit variations to substantive matters of significant importance or value (such as the inclusion of residual rights). BC Hydro's evaluation criteria were detailed in the RFP documents and the process for handling and evaluating submissions was established prior to bid submission. To ensure fairness in the evaluation process, an Independent Observer was retained to monitor the evaluation of proposals and any subsequent discussions with proponents, particularly those who disclosed prior relationships with BC Hydro or any B.C. Government entity. The process was confirmed to be fair and transparent by the Independent Observer, as noted in the report contained in Appendix B.

BC Hydro conducted a risk assessment of each proposal, examining aspects of the project including financial strength, technical aspects, First Nations engagement, permitting/approvals, and energy source data. BC Hydro reviewed any proposed variations to the EPA and completed a quantitative evaluation of proposed product and pricing attributes. Based on the results of these assessments, BC Hydro selected a number of proponents for post-proposal discussions focused on clarifying areas of risk, negotiating proposed variations, and seeking further price reductions.

Following these meetings, BC Hydro selected 27 projects for EPA awards based on the final EPA terms and conditions, including price, First Nations consultation, and risk assessment. BC Hydro acquired the Environmental Attributes from each project and also received residual rights in the form of term extension options for nine of the projects.

Achieving Cost-Effective Results for Ratepayers

The Clean Power Call was competitive and featured robust industry participation, providing BC Hydro with the ability to select some of the least-cost, best-value proposals from a large pool of submissions. The price to be paid for this electricity met BC Hydro's expectations based on comparisons to other BC Hydro processes and similar processes undertaken by other jurisdictions, and to 2008 LTAP projections. BC Hydro's Clean Power Call process has resulted in the acquisition of cost-effective clean, renewable electricity for BC Hydro's ratepayers.

2. BACKGROUND

a) Call Highlights and Context

Overview of the Clean Power Call Process

The Clean Power Call RFP was issued on June 11, 2008. It was structured as an RFP to allow more flexibility in working with IPPs and to come up with cost-effective EPA terms and conditions. The RFP approach was helpful in accommodating larger projects requiring additional development time and warranting Commercial Operation Dates (CODs) as late at November 2016.

In November 2008, BC Hydro received 68 proposals from 43 proponents, representing more than 17,000 GWh/year of energy. In November 2009, BC Hydro announced its decision to proceed with discussions aimed at securing EPAs with the 13 most cost-effective proposals. BC Hydro contacted the proponents of 34 additional proposals to afford them the opportunity to make their respective proposals more cost-effective. BC Hydro eliminated the remaining 21 proposals because the proposals were either withdrawn or did not meet the RFP requirements or were viewed as having excessive development risk.

On March 11, 2010 BC Hydro announced that it had selected 19 proposals for EPA awards under the Clean Power Call. Subsequently, eight additional proposals were selected for EPA awards with the last award occurring in early August 2010. The 27 selected proposals resulted in 25 EPAs (for one proponent, three proposals were combined into a single EPA) accounting for 3,266 GWh/year of firm energy and 1,168 MW of capacity. Based on an assumed attrition factor of 30 per cent, the EPAs account for 2,286 GWh/year of firm energy for planning purposes.

Context

The Clean Power Call is consistent with the 2007 Energy Plan and the British Columbia Utilities Commission (BCUC) endorsement of the Clean Power Call's clean or renewable eligibility criteria in the 2008 LTAP Decision.[1] Furthermore, the Clean Power Call is aligned with the British Columbia's energy objectives set out in section 2 of the Province's *Clean Energy Act (CEA)*.

The 2007 Energy Plan

The 2007 Energy Plan was released by the Province on February 27, 2007. The Clean Power Call aligns with Policy Action No. 21 of the 2007 Energy Plan, which indicates that clean or renewable electricity generation must continue to account for at least 90 per cent of total generation.[2]

Other 2007 Energy Plan Policy Actions relevant to the Clean Power Call are:

- **Policy Action No.10** – ensure self-sufficiency to meet electricity needs by 2016. Refer to Section 5 of the Report for BC Hydro's load/resource balance, including the two changes resulting from Special Direction No. 10 to the BCUC, namely: (a) the 2,500 GWh/year non-firm energy/market allowance has been removed from the energy load/resource balance after 2015; and (b) the 400 MW market reliance has been removed from the capacity load/resource balance after 2015. The BCUC endorsed these two changes as part of its 2008 LTAP Decision.[3]

- **Policy Action Nos. 18 and 19** – all new electricity generation projects will have zero net greenhouse gas (GHG) emissions by their CODs, and all existing thermal generation power plants will have zero net GHG emissions by 2016, respectively. The B.C. Government has legislated these two Policy Action items pursuant to the *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008* [4] (*Emissions Standards Act*). Refer to Section 6 of the Report, where the EPAs are compared to a green-field generic 250 MW combined cycle gas turbine (CCGT) with 100 per cent of GHG emissions offset from its COD.

- **Policy Action No. 20** – require zero GHG emissions from any coal thermal electricity generating facilities. As part of its 2008 LTAP, BC Hydro examined the current status of coal-fired generation with carbon capture and sequestration (CCS) and concluded that coal-fired generation with CCS is not a commercial technology at this time.[5] Consequently the EPAs are not compared to coal-fired generation with CCS in Section 6 of the Report.

- **Policy Action No. 22** – replace the firm energy supply from Burrard Thermal Generating Station (Burrard) with other resources. On October 28, 2009, the B.C. Cabinet issued Direction No. 2 to the BCUC, which provides that the BCUC "must exercise its powers and perform its duties under the [*UCA*] in accordance with the criteria that … [BC Hydro] must plan to rely on Burrard for no more than … 0 GWh/year of firm energy". This is reflected in the energy load/resource balances set out in Section 5 of the Report.

BCUC 2008 LTAP Decision

In the 2008 LTAP Decision, the BCUC endorsed the Clean Power Call RFP clean or renewable eligibility criteria given the government's energy objectives.[6] Accordingly, natural gas-fired generation such as a CCGT was not eligible for the Clean Power Call. In Section 6 of this Report, BC Hydro compares the EPAs to a 250 MW CCGT with 100 per cent of GHG emissions offset from its COD. Given the BCUC's eligibility endorsement, a CCGT is not relevant in terms of whether the Clean Power Call ought to have been an "all source" power acquisition process.

Clean Energy Act

The C*lean Energy Act*, which was brought into force on June 3, 2010, contains several provisions which reinforce the 2007 Energy Plan including British Columbia's energy objectives of achieving electricity self-sufficiency and generating at least 93% of the electricity in B.C. from clean or renewable resources. The Clean Power Call aligns with both of these British Columbia energy objectives.

---

[1] *In the Matter of British Columbia Hydro and Power Authority and an Application for Approval of the 2008 Long Term Acquisition Plan*, *Decision*, 27 July 2009, page 124.

[2] Pursuant to the *Clean Energy Act* (*CEA*), S.B.C. 2010 c.22, section 2, the legislated clean, renewable electricity generation target is now at least 93 per cent.

[3] 2008 LTAP Decision, note 1, page 44 (with respect to the 2,500 GWh/year non−firm market allowance); and BCUC Order No. G-150-09, page 3 (with respect to the 400 MW of market reliance).

[4] S.B.C. 2008, c. 20. Given Royal Assent on May 29, 2008; the relevant part (section 2) in force by regulation.

[5] In a report entitled "*Clean Coal Power Generation by CO_2 Sequestration*", Powertech Labs Inc. concluded that the state of key components of CCS technology is such that it cannot be considered in commercial application of coal-fired generation. Although pilot plants are being considered and pursued, the viability of these technologies on a commercial application scale may not be known until 2017 or later. There are also legal, regulatory and public acceptance issues that likely need to be addressed before CCS technology can be considered on a commercial scale in B.C.

[6] 2008 LTAP Decision, note 1, page 124.

3. CALL IMPLEMENTATION AND EVALUATION

a) RFP Process

The acquisition process for the Clean Power Call employed an RFP process that allowed proponents to propose variations to BC Hydro's preferred EPA terms and conditions. In addition, the process allowed for direct negotiation of price and terms between BC Hydro and a proponent. BC Hydro's F2006 Call used a Call for Tenders (CFT) process, which offered limited flexibility and no opportunity for negotiation of price and other material terms and conditions.

The Clean Power Call RFP was issued on June 11, 2008. In October 2008, BC Hydro retained John Singleton of Singleton Urquhart LLP to act as an Independent Observer for the implementation of the Clean Power Call. His main role was to monitor the evaluation of proposals and any subsequent discussions with proponents, particularly those proponents who disclosed prior relationships with BC Hydro or any B.C. Government entity. The Independent Observer also assessed whether any unfair bias was shown in favour of any proponent.

A process for handling and evaluating submissions was established prior to bid submission. Figure 3-1 outlines the evaluation process. The evaluation criteria for the RFP were laid out in section 20 of the RFP.

The RFP evaluation process began with the receipt of proposals in November 2008. The RFP process was completed in August 2010 with the award of the final EPA. In total, BC Hydro awarded 25 EPAs for 27 projects to 18 different Clean Power Call proponents.

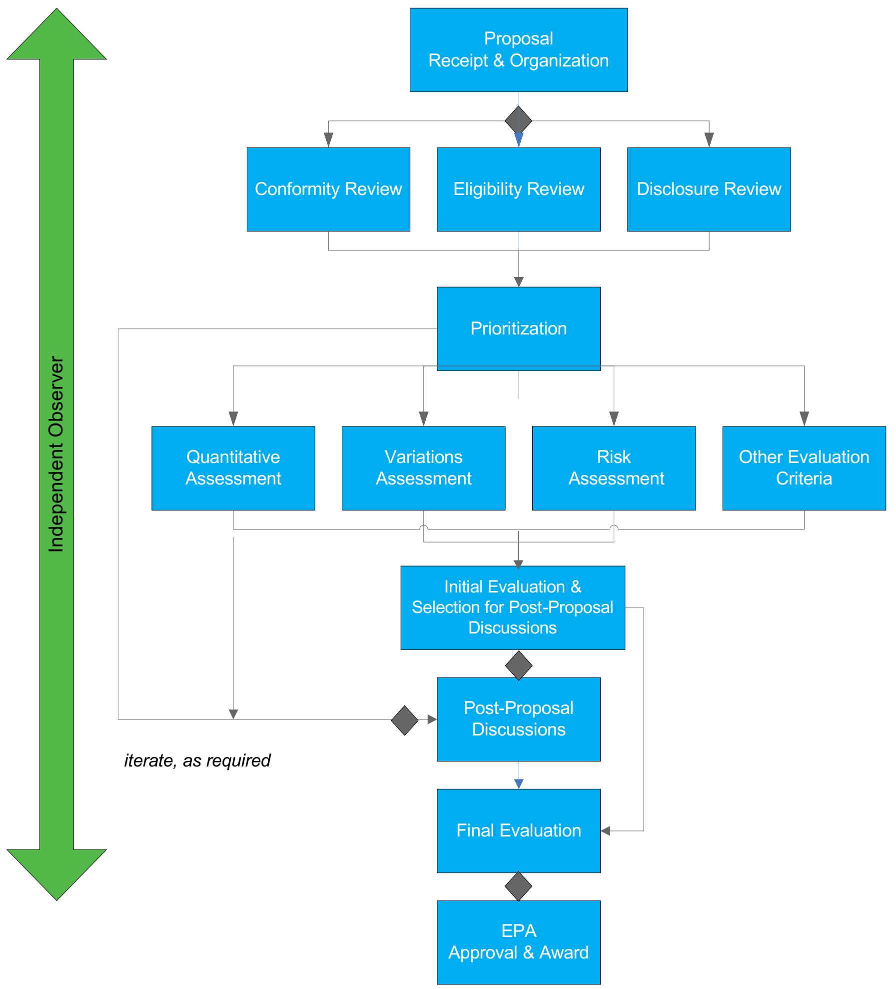
b) RFP Overview

The key preferred EPA terms and conditions of the Clean Power Call RFP are summarized below.

Product

BC Hydro defines "firm energy" as a volume of energy with a contractually assured delivery, which a proponent must commit to delivering over a specified period. Proponents were permitted to make a commitment to either seasonally or hourly firm energy deliveries. Seasonally firm energy refers to the volume of energy that a proponent commits to deliver to

Figure 3-1 Clean Power Call RFP Evaluation Process



BC Hydro in a season (i.e., in specified three-month periods). Hourly firm energy refers to the volume of energy that a proponent commits to deliver in each hour.

Fuel Type

The entire output from a project bid into the Clean Power Call was required to qualify as clean or renewable electricity in accordance with the "*British Columbia's Clean or Renewable Electricity Definitions*" published by the B.C. Ministry of Energy, Mines and Petroleum Resources. All fuel types meeting these definitions were eligible in the Clean Power Call, other than forest-based biomass.

Project Size

All proponents bidding into the Clean Power Call were required to commit to delivering a minimum of 25 GWh/year of firm energy.

Commercial Operation Date (COD) and Term

Proponents were permitted to select a guaranteed COD between November 1, 2010 and November 1, 2016 and an EPA term ranging from 15 to 40 years, commencing from the COD. The latter COD timing is in alignment with the 2007 Energy Plan, which indicates that B.C. is to achieve electricity self-sufficiency by 2016, and allows larger projects with extended CODs to be accommodated. The term length is based on permitting considerations and the typical life of clean and renewable technologies.

Liquidated Damages (LDs)

After the first anniversary of COD, LDs are payable to BC Hydro (either on an hourly or seasonal basis) for firm energy delivery shortfalls. The amount of LDs is the greater of market price less the firm energy price (adjusted for delivery to the Lower Mainland) and $5.00 (adjusted annually for Consumer Price Index (CPI) from January 1, 2009) for each MWh of delivery shortfall. The total firm energy delivery shortfall LDs for each year are limited to an amount equal to 200 per cent of the performance security for that year.

c) Proposal Submissions

A total of 75 proponents with 168 separate projects totalling almost 18,000 MW of nameplate capacity registered for the Clean Power Call RFP on August 12, 2008. Proposals were due on November 25, 2008. BC Hydro received 68 project proposals from 43 different proponents representing approximately 17,000 GWh/year of firm energy. The submissions included 45 hydro projects, 19 wind projects, two waste heat projects, one biogas project, and one biomass project.

Following the receipt of proposals, conformity and eligibility reviews were conducted with the assistance of outside legal counsel. No proposals were disqualified based on the conformity review but seven proposals were eliminated based on failure to meet the eligibility requirements.

d) Risk Assessment

BC Hydro conducted a Risk Assessment to assess the development and delivery risks associated with each proposal.

Process

Each proposal was assessed by five separate Risk Assessment teams consisting of BC Hydro staff and external consultants with relevant expertise. Each team focused on reviewing one of five discrete risk areas being assessed: financial, technical, First Nations, permitting/approvals and energy source. Each Risk Assessment team was requested to review only those areas of the proposal relevant to their assessment and none of the teams had access to the commercial elements of the proposals, which contained bid price information and other commercial terms.

Each Risk Assessment team developed a risk rating for each project, in their respective area of focus, on a scale of low, medium or high. Ratings were based on criteria defined by each team prior to receiving proposals. In addition to the ratings, the Risk Assessment teams provided a brief summary of the major risks for each project. The review by the Risk Assessment teams was completed by February 2009.

The Risk Assessment teams were tasked with evaluating the following aspects of all proposals:

1. **Finance:** This team evaluated the financial strength of proponents and their partners in relation

to the capital required to develop the projects. This team also assessed whether there was a risk of the project not being developed due to a lack of debt or equity financing.

2. **Technical:** This team assessed the technical aspects of project development, including the feasibility of the construction schedule and the operational plans proposed by proponents.

3. **First Nations:** This team initially assessed the engagement activities of the proponents with First Nations and assessed the extent of any development risk, particularly related to permitting. After February 2009, as the result of a court decision, EPA filings with the BCUC needed to contain an assessment of the adequacy of First Nations consultation with respect to projects receiving EPA awards. To prepare for its BCUC filing requirements, BC Hydro assessed the adequacy of First Nations consultation undertaken by proponents for all projects being considered for EPA awards.

4. **Permitting and Approvals:** This team assessed project development with respect to obtaining the necessary permits and approvals. This assessment included a determination of whether the necessary permits and approvals have been identified as well as the reasonableness of the plan and schedule for obtaining any outstanding permits and approvals and the risks to receiving these permits and approvals.

5. **Energy Resource:** This team reviewed the energy source data submissions. The energy source data was assessed for the strength of data, data analysis and modeling methodology to ascertain the resource availability for the proposed projects. An analysis reflecting the energy expected versus the firm energy profile contained in the proposals was also undertaken.

Results

Upon completion of the individual Risk Assessment for each of the five risk categories described above, the results were calibrated across the various projects and aggregated by project to generate an overall development and delivery risk rating for each project.

The Risk Assessment was not intended to be used as a pure pass or fail decision, although BC Hydro retained the right to remove any proposal from consideration on the basis of risk. BC Hydro exercised this right in situations where reasonable development efforts had not been demonstrated by the proponent, or where the risks associated with project development made it unattractive to pursue. In November 2009, BC Hydro rejected 10 Clean Power Call proposals based on excessive development risk.

e) Variations Review

The Specimen EPA issued on October 21, 2008 represented BC Hydro's preferred terms and conditions. The Specimen EPA was based on an IPP project proposed by a single corporation, offering seasonally firm energy with a direct interconnection to the transmission system. Some proponents were able to offer additional value to BC Hydro or had unique situations not contemplated in the Specimen EPA. To accommodate such situations, BC Hydro indicated it would consider two types of variations to the Specimen EPA:

- **Essential Variations** – modifications to the Specimen EPA necessary to enable the proponent to design, build and operate its project in compliance with the EPA. Essential variations were to be included in the offered Firm Energy Price (FEP).

- **Value Variations** – modifications, generally value enhancements, to the Specimen EPA that BC Hydro could choose to incorporate into the EPA. Value variations could be priced with a modification to the offered FEP.

In submitting variations, proponents were requested to submit a redlined version of the Specimen EPA, with a brief commentary indicating: (i) whether variations were essential variations or value variations, and (ii) the reasons for the variations. In the event that the variation(s) could not be captured by marking up the Specimen EPA, the proponent had the option of submitting a separate document describing the proposed variations in place of or in addition to the redlined Specimen EPA. Proponents were strongly encouraged to submit proposals that conformed to the preferred terms and conditions, to limit variations to matters of significant importance, and not to expect post-proposal discussions (i.e., sufficient information was required in the variation proposals to facilitate full assessment by BC Hydro).

The Variation Review team assessed the variations proposed by each proponent. In some situations, the proposed variations were modified and/or additional value variations were proposed by proponents following post-proposal discussions. These modified and/or additional variations were also reviewed by the Variation Review team. Variations that were acceptable to BC Hydro were incorporated into the EPAs for those projects selected for awards.

f) Quantitative Evaluation

The Clean Power Call RFP permitted proponents to select a number of different options (e.g., product and pricing attributes) when submitting their proposals. As a result, a process was required to fairly compare one proposal against another. To compare proposals with different attributes, an adjusted Firm Energy Price (FEP) was calculated for each proposal. The first step in computing the adjusted FEP was to levelize the offered FEPs, which took into account the pricing attributes chosen by the proponents. The second step was to adjust the levelized FEPs for product attributes and for project location relative to the Lower Mainland.

Step 1: Levelizing the FEPs
To compute the levelized FEP, BC Hydro divided the present value (PV) of the firm energy purchases for each proposal, based on the proponent's selected options (e.g., COD, contract term, escalation rate), by the PV of firm energy flow to be delivered over the term of the EPA. The nominal discount rate used for the PV calculation was 8 per cent, including a 2.1 per cent inflation component.

Step 2: Price Adjustments
The levelized FEP was adjusted to account for differences in product attributes, and in project location relative to the Lower Mainland. Adjustments were made for hourly firm energy, wind integration, Network Upgrade (NU) costs borne by BC Hydro, Cost of Incremental Firm Transmission (CIFT) and energy losses.

Hourly Firm: An adjuster (expressed in $/MWh) was deducted from the levelized FEP for proponents that committed to deliver hourly firm energy. The magnitude of the adjuster depended on the proponent's profile of on-peak hourly firm energy. For a project with a “flat” hourly firm energy profile, the adjuster was approximately $4.00/MWh.

Wind Integration: Due to the intermittent and variable nature of wind energy output, a $10/MWh adjustment was added to the levelized FEP of wind projects to account for the incremental cost of integrating wind projects into the BC Hydro generation system.

Network Upgrades: The NU adjustment was based on an estimate of the costs borne by BC Hydro to interconnect projects to the grid. The estimated NU costs were provided in interconnection studies conducted on a stand-alone basis for each project. The applicable NU amounts were multiplied by 150 per cent and converted into a $/MWh adjustment and then added to the levelized FEP offered by the proponent.

CIFT: The CIFT adjustment was based on a report entitled “*Bulk Transmission System Cost of Incremental Firm Transmission for BC Hydro's 2008 LTAP Base Plan and Contingency Resource Plans CRP1 and CRP2*” dated January 15, 2009. The CIFT provides a general indication of the long term unit cost of bulk transmission system reinforcement from one region to the next region. The CIFT for non-adjacent regions can be determined by summing the region to region costs. To calculate the CIFT adjustment for each project, CIFT costs (expressed in $k/MW-year) for the largest incremental flows in the F2010 Stage[7] were used. The cumulative CIFT costs for each project were converted into a $/MWh adjustment and then added to the levelized FEP for that project.

Losses: Studies were conducted to determine the losses associated with delivering the energy from each project location to the Lower Mainland on a stand-alone basis. These losses were converted into a $/MWh adjustment and added to the levelized FEP price for the project.

The result of the above adjustments is a levelized adjusted FEP on a stand-alone basis for a common product, i.e., seasonally firm energy delivered to the Lower Mainland.

Projects that were part of a "transmission cluster" were further evaluated for cost-effectiveness. A transmission cluster is defined as a group of projects that trigger network upgrades that are in addition to their stand-alone NU requirements as a result of their relative locations on the transmission system. In evaluating a transmission cluster, the incremental cost of the additional network upgrade was allocated to each project in the cluster on a pro-rated basis.

g) Discussions and EPA Variations

Based on the results of the Risk Assessment, Variation Assessment and Quantitative Assessment, BC Hydro selected more than half of proponents and projects for an initial round of post-proposal discussions which took place in March and April 2009. For these discussions, projects were selected primarily on the basis of price and strategic interest (e.g. location, storage capability). Discussions were focussed on seeking clarification on any areas of risk, negotiating any proposed variations to the Specimen EPA, and seeking further price reductions. As a result of these discussions, price reductions were received for several projects.

In November 2009, 21 proposals, representing approximately 4,200 GWh/year of firm energy, were eliminated from the Clean Power Call because the proponents had withdrawn their proposals, the proposals did not meet the requirements of the RFP or the proposals were considered to have too high a level of risk. Thirteen proposals were identified as the most cost-effective and further discussions aimed at securing EPAs, as well as further price reductions, were carried out with the proponents of these proposals. The proponents of the remaining 34 proposals were given an opportunity to make their proposals more cost-effective.

Discussions with the proponents of the 47 remaining proposals commenced in November 2009. These final discussions continued to focus on clarifying any areas of risk, but also sought residual rights (either in the form of a term extension option for BC Hydro or ownership rights, if the project was considered to be of strategic interest due to, for example, size or storage capability), any additional information required to conclude the First Nations consultation assessment, and resolution of any variations to the Specimen EPA. The Risk, Variation, and Quantitative Assessments were updated as necessary following all discussions.

h) Final Portfolio Selection

Based on the outcome of the meetings described above, 27 projects, representing 3,266 GWh/year of firm energy, were selected to receive EPAs, as summarized in Table 3-2. Three of the projects from one proponent were combined into a single EPA; thus, a total of 25 EPAs were awarded. A more detailed listing of the projects being awarded EPAs is contained in Appendix A.

The decision to offer EPAs to these 27 projects was based on the final EPA terms and conditions, including the prices offered by the proponents, the adequacy of First Nations consultation, and the Risk Assessment. Also, the proponents of nine of the selected projects provided residual rights to BC Hydro in the form of term extension options.

i) Summary of RFP Proposals

Table 3-3 summarizes the treatment of the RFP proposals, starting with the receipt of proposals in November 2008 and culminating with the final EPA awards in July 2010.

Table 3-2 Summary of Projects for Awarded EPAs

Proponent Name	Project Name	Location	Energy Source	Capacity (MW)	Firm Energy (GWh/yr)
AltaGas Ltd.	Crowsnest Pass Power	Sparwood	waste heat	11	46
Box Canyon Hydro Corporation and Sound Energy Inc.	Box Canyon	Port Mellon	hydro	15	50
Castle Mountain Hydro Ltd.	Benjamin Creek	McBride	hydro	6	27
C-Free Power Corp.	Jamie Creek	Gold Bridge	hydro	19	41
Cloudworks Energy Inc.	Big Silver-Shovel Creek	Harrison Hot Springs	hydro	37	110
Cloudworks Energy Inc.	Northwest Stave River	Mission	hydro	18	44
Cloudworks Energy Inc.	Tretheway Creek	Mission	hydro	21	56
CP Renewable Energy (B.C.) Limited Partnership	Quality Wind	Tumbler Ridge	wind	142	434
Creek Power Inc.	Boulder Creek	Pemberton	hydro	23	48
Creek Power Inc.	North Creek	Pemberton	hydro	16	34
Creek Power Inc.	Upper Lillooet River	Pemberton	hydro	74	143
ENMAX-Syntaris Bid Corp.	Culliton Creek	Squamish	hydro	15	56
Finavera Renewables Inc.	Bullmoose Wind	Tumbler Ridge	wind	60	142
Finavera Renewables Inc.	Meikle Wind	Tumbler Ridge	wind	117	327
Finavera Renewables Inc.	Tumbler Ridge Wind	Tumbler Ridge	wind	45	140
Finavera Renewables Inc.	Wildmare Wind	Chetwynd	wind	71	204
Pacific Greengen Power	Bremner / Trio	Harrison Hot Springs	hydro	45	148
Kwagis Power Limited Partnership	Kokish River	Port McNeill	hydro	45	183
Long Lake Joint Venture	Long Lake	Stewart	hydro	31	139
NI Hydro Holding Corp.	Ramona 3 + Chickwat Creek + CC Creek	Sechelt	hydro	45	198
Plutonic Power Corporation / GE Energy Financial Services Co.	Upper Toba Valley	Powell River	hydro	124	214
Run of River Power Inc.	Mamquam	Squamish	hydro	25	68
Sea Breeze Energy Inc.	Knob Hill Wind	Port Hardy	wind	99	281
Selkirk Power Company Ltd.	Beaver River	Golden	hydro	44	86
Swift Power Corp.	Dasque-Middle	Terrace	hydro	20	46
TOTAL				1,168	3,266

Table 3-3: Treatment of RFP Proposals

Event	Date	Proponents	Proposals	Firm Energy (GWh/year)
RFP Submissions	Nov. 2008	43	68	17,700
Eliminations due to: • Conformity Review • Eligibility Review • Risk Assessment • Withdrawal		(12)	- (7) (10) (4)	(4,200)
Short-listed Proposals	Nov. 2009	31	47	13,500
Eliminations due to: • Not Cost Effective • Excessive Risk		(13)	(17) (3)	(10,234)
Completion of EPA Awards	July 2010	18	27	3,266

Table 3-4 shows a comparison of bid prices for the proposals selected for EPA awards. EPAs were awarded to lowest cost short-listed proposals in terms of levelized adjusted FEP with the exception of three short-listed proposals which were rejected due to excessive development risk.

Table 3-5 summarizes key data for the projects selected for EPA awards. As shown, most of the projects are run-of-river hydro and comprise nearly 60 per cent of the total energy. However, the six wind projects account for almost half of the total firm energy.

The weighted-average energy prices shown in Table 3-5 (except for the adjusted FEP) are typically measured at the plant gate level. The derivation of these plant gate prices is briefly summarized in Table 3-6.

As shown in the jurisdictional comparison contained in Section 6 of this Report, the energy prices being paid under BC Hydro's Clean Power Call compare favourably with renewable power prices being paid by other electric utilities in North America.

Table 3-4: Price Comparison for Awarded EPAs

Project Number	Firm Energy - $/MWh			Total Energy - $/MWh
	Final Bid Price (Jan. 2009$)	Levelized Plant Gate Price	Levelized Adjusted FEP	Levelized Plant Gate Price
1	137.00	105.08	105.36	99.55
2	105.00	100.11	107.40	85.70
3	120.00	107.32	112.24	93.70
4	137.92	113.93	113.83	97.82
5*	99.00	89.97	117.37	86.60
6	113.70	117.54	117.76	94.19
7	95.00	83.05	120.81	76.21
8	143.50	104.25	122.44	83.41
9	149.64	122.53	122.66	103.74
10	156.00	119.92	124.32	115.16
11	144.00	119.53	124.54	118.48
12*	102.25	92.92	125.95	89.72
13*	109.00	99.05	126.32	94.89
14	148.00	130.65	126.95	107.20
15	151.89	127.77	127.30	105.93
16	148.00	115.82	127.40	90.40
17*	123.14	108.77	128.16	105.75
18	138.10	124.88	129.48	108.63
19	130.00	115.10	130.25	115.10
20*	108.00	98.15	131.49	94.06
21	135.87	125.60	132.34	106.53
22	143.90	121.23	132.90	119.62
23	155.43	124.67	133.80	95.30

Notes:

a) Projects are listed based on the ranking of the levelized adjusted Firm Energy Price (FEP) which was the evaluation benchmark for decision-making purposes.

b) The five projects flagged with an asterisk (*) were included in "transmission clusters" which resulted in incremental network upgrade costs. The allocation of these costs resulted in adjusted FEP figures which were $3-4 per MWh higher than those shown in the table, which were calculated on a stand-alone project basis.

c) Prices are shown for 23 EPAs rather than the 25 awarded given that there is a composite price figure for one proponent with 3 EPAs reflecting a common Network Upgrade for all 3 of its projects.

In its decision making for cost-effective awards, BC Hydro used the levelized adjusted Firm Energy Price since it places all projects on a level footing by adjusting for varying escalation factors and a common delivery point (i.e. Lower Mainland). As shown in Table 3-5, the levelized adjusted FEP for the projects selected ranged from $105.4 to $133.8 per MWh with a weighted-average adjusted FEP of $124.3/MWh, with little difference between hydro and wind projects.

Table 3-5: Key Data for Projects with EPA Awards*

	Hydro	Wind	Total**
Number of Projects	20	6	27
Firm Energy (GWh/year)	1,692	1,528	3,266
Total Energy (GWh/year)	2,342	1,644	4,051
Firm Energy Price ($/MWh)			
Final Bid Price (Jan. 2009 $)	95.0 to 156.0	99.0 to 143.9	95.0 to 156.0
Weighted-Average Bid Price	139.9	116.6	128.5
Levelized Plant Gate Price	83.1 to 130.7	90.0 to 121.2	83.1 to 130.7
Weighted-Average Plant Gate Price	118.0	103.1	111.3
Levelized Adjusted FEP	105.4 to 133.8	117.4 to 132.9	105.4 to 133.8
Weighted-Average Adjusted FEP	123.0	126.5	124.3
Total Energy Price ($/MWh)			
Levelized Plant Gate Price	76.2 to 118.5	86.6 to 119.6	76.2 to 119.6
Weighted-Average Plant Gate Price	101.7	99.6	100.7

* Prices shown are on a stand-alone project basis.

** Includes one waste heat project which is not segregated for confidentiality reasons.

The weighted-average levelized and adjusted FEP of $124.3/MWh is a reasonable proxy for the costs that will be borne by BC Hydro's ratepayers for electricity being acquired pursuant to the Clean Power Call. BC Hydro's future Revenue Requirements Applications (RRAs) will include the total cost of energy being purchased under the awarded EPAs (i.e., the cost of all firm and non-firm energy and associated losses) as the projects reach COD and begin delivering energy. In addition, future RRAs will reflect the cost of capital additions for upgrading the transmission and distribution systems in order to connect the IPP projects to BC Hydro's grid.

j) Independent Observer's Report

The Independent Observer's report regarding the Clean Power Call RFP process is contained in Appendix B. The Independent Observer concluded that "... the process has been fair, transparent and without any demonstrated bias shown towards any particular proponent".

Table 3-6: Derivation of Plant Gate Prices

Final Bid Price for Firm Energy (Plant Gate)	$128.5/MWh	Contractual EPA price (stated in Jan. 2009$) which is escalated each year based on escalation factors chosen by proponents
Levelized Plant Gate Price for Firm Energy	$111.3/MWh	Price in 2009$ derived from a present value calculation (using an 8% discount rate) which adjusts for varying escalation rates, CODs and EPA terms; lower than contractual bid price since post-COD escalators limited to 0-50% of CPI
Levelized Plant Gate Price for Total Energy	$100.7/MWh	Blended price for both firm and non-firm energy. Non-firm energy comprises about 20% of total deliveries and is priced at market levels which is lower than the FEP

[7] F2010 Stage refers to the facilities that are expected to be in service in F2010 and later.

4. FIRST NATIONS AND STAKEHOLDER ENGAGEMENT

a) Dialogue and Information Sessions

The Clean Power Call engagement process built upon the previous engagement efforts of the F2006 Call Open Call for Power. During summer 2006, BC Hydro engaged IPPs in a series of dialogue sessions to solicit input into the design of the Clean Power Call, including improvements to the acquisition process and enhanced contractual terms and conditions. BC Hydro held a follow-up workshop with some of the IPP dialogue participants and included the B.C. Government and representatives from the financial, construction and legal communities, to discuss call design and to further explore key themes identified during the dialogue sessions. In mid-2007, BC Hydro hosted an information session titled "*Understanding BC Hydro's System Needs*", which detailed BC Hydro's system needs, short-term and long-term system planning and system constraints. Input was sought from First Nations, and from IPPs and other stakeholders, on how to meet system needs through future calls.

BC Hydro released the proposed terms of the Clean Power Call on November 14, 2007 and sought input on these terms from First Nations, and stakeholders including IPPs and the B.C. Government. To improve the understanding of the draft documents and to encourage discussion and facilitate informed feedback, BC Hydro held an information session on the proposed design of the Clean Power Call in Vancouver in November 2007. Following this session, BC Hydro received over 40 submissions with about 600 written comments on the draft Term Sheet documents. Many of these submissions highlighted the need for further discussion about including residual rights as a call term. As a result, two small dialogue sessions were held around year-end 2007 to discuss the potential impacts on call participants and to explore options that would make it worthwhile for the industry to consider residual rights.

Input received through the engagement process was used to inform the design of the Clean Power Call terms and EPA. The RFP terms were released June 11, 2008. A full-day engagement session for potential applicants and interested parties was held in July 2008. BC Hydro reviewed and provided details on the RFP terms, registration process and timeline followed by a BCTC overview of the details and deadlines for the interconnection processes.

BC Hydro held a final engagement session for Clean Power Call proponents in October 2008. Proponents were encouraged to attend the session to review proposal requirements, the application process, specimen EPA formulae and post-proposal submission processes.

Details of these sessions are further summarized in Table 4-1.

b) First Nations Engagement Regarding RFP Design

First Nations were invited to participate in all of BC Hydro's engagement activities listed above. BC Hydro also held two sessions for First Nations only. Representatives from BC Hydro, the Ministry of Environment, Integrated Land Management Bureau, and the Environmental Assessment Office were available to address questions raised by the session participants. One session was held prior to the Clean Power Call being released to provide participants an opportunity to comment on the draft RFP terms and offer improvements. A second session was held after the RFP was issued to explain the final terms of the Clean Power Call.

Invitation letters for these two sessions were sent to more than 200 First Nations and approximately 30 tribal councils within B.C. In the invitation, BC Hydro offered to cover travel and accommodation expenses to ensure that travel costs were not a participation barrier.

Table 4-2 provides a summary of the First Nations specific engagement sessions conducted before and after the Clean Power Call was launched.

Comments received from First Nations contributed to BC Hydro's decision making on the treatment of residual rights. Most comments from First Nations were not directly applicable to the terms of the Clean Power

Table 4-1: Summary of Dialogue and Information Sessions

Session	Description	Outcome
IPP Dialogue Sessions Summer 2006: ▪ June 29 ▪ July 5,10,11,14,18 and 21 ▪ August 9 and 15	These dialogue sessions were designed to stimulate discussion and identify items that should be considered as part of the Clean Power Call, including improvements to the acquisition process and enhanced contractual terms and conditions.	*9 sessions were held with 37 participants.* Key issues included: • Learnings from F2006 Call • Types of acquisition process (structured CFT or RFP) • Risk allocation • EPA terms • Reducing attrition • Transmission issues Feedback obtained at these sessions helped to inform the design of the draft terms of the Clean Power Call. Sessions summaries were completed and posted on BC Hydro's website.
Workshop on Clean Power Call Design September 21, 2006	BC Hydro gathered with IPPs, BCTC, the B.C. Government and representatives from the financial, construction and legal communities to have a broad discussion regarding design of the Clean Power Call and to explore possible solutions for several key themes identified during the IPP dialogue sessions.	*30 attendees participated in this broad discussion.* Participants worked in break-out groups to discuss financial, transmission/interconnection, construction, permitting and EPA issues. Feedback obtained at these sessions helped to inform the design of the draft terms of the Clean Power Call. A workshop summary was posted on BC Hydro's website.
Understanding BC Hydro's System Needs June 6, 2007	This session was designed to create a greater understanding of BC Hydro's system needs, long and short-term system planning and system constraints and to obtain input on how to meet system needs through future calls.	*185 registered participants* Presentations from this session were posted on BC Hydro's website.
Clean Power Call Information Session November 27, 2007	This session gave BC Hydro a chance to provide more details on the Clean Power Call and offered an opportunity for participant questions and provide feedback on the Clean Power Call and the draft Term Sheet documents. Several break-out group sessions were also organized during the afternoon to allow for more in-depth discussion on specific issues.	*145 registered participants* Participant feedback was considered in terms of refining the Clean Power Call. Key issues were: • Treatment of Environmental Attributes • Residual rights inclusion in the Clean Power Call • Freshet caps • Wind integration costs
Residual Rights Dialogue Sessions December 12, 2007 January 15, 2008	Smaller dialogue sessions were used to review and explore the inclusion of residual rights terms in the Clean Power Call.	*Each session consisted of a working group of approximately 20 attendees.* Key issues were: • Impact on competitiveness and pricing • Creation of additional land use conflict • Motivation for including residual rights in the draft terms • Project lifespan and actual value of plant at transfer
BC Hydro/BCTC Joint Information Session on Clean Power Call RFP July 8, 2008	The morning session, hosted by BC Hydro, provided potential participants with an overview of the revised RFP and contract terms, the registration process and the timeline for the Clean Power Call. The afternoon session, hosted by BCTC, provided an overview of the important details and timelines for the transmission and distribution interconnection processes.	*Over 302 registered participants* Presentations from this session were posted on BC Hydro's website.
Proponent RFP Information Session October 23, 2008	Registered proponents were given an opportunity to review proposal requirements, specimen EPA formulae and post-proposal submission processes.	*162 registered participants* Questions dealt with all aspects of the RFP process.

Table 4-2: First Nations Engagement Sessions

Session	Description	Outcome
Information Session on Draft Clean Power Call Terms December 6, 2007	Participants were provided with an overview of the draft terms and conditions of the Clean Power Call.	*22 registered participants* Feedback from this session focused on a number of issues including: • General dissatisfaction with residual rights clauses • Capacity funding • Treatment of First Nations consultation in the risk assessment stage of the RFP
Information Session after Issuance of Clean Power Call RFP July 10, 2008	Participants were provided with an overview of the terms of the Clean Power Call RFP.	*24 registered participants* Feedback from this session focused on a number of issues, including: • Responsibility for consultation between the proponent, government or BC Hydro • First Nations' access to resources for development opportunities Identification of revenue sharing opportunities for First Nations and potential sources

Call; however, the comments received have been considered for BC Hydro's subsequent engagement processes.

c) Reasonableness and Adequacy of First Nations Consultation

Prior to entering into the EPAs, BC Hydro reviewed the First Nations consultation records of Clean Power Call proponents to determine if consultation had been reasonable and adequate. The Information and documentation requested by BC Hydro from proponents was as follows:

First Nations Identification

Information that identified how proponents determined which First Nations to consult with in relation to their projects including:

- A statement of how proponents determined which First Nations to consult and a list of such First Nations (including key contact persons); and

- Copies of directions from other Crown agencies indicating the specific First Nations to be consulted with as well as supporting documentation such as letters from First Nations or tribal councils and letters from other Crown agencies such as the Integrated Land Management Bureau, which is responsible for administering and adjudicating B.C. Crown land tenures as well as coordinating permitting for clean energy projects.

Project Impacts on First Nations Interests

To assess the potential degree of the project impacts on asserted aboriginal rights and title, BC Hydro considered:

- Information on the level of consultation to this stage such as the nature of information shared with First Nations about the project, the opportunities for First Nations to identify potential impacts, when consultation began (and how frequently consultation occurred) and plans for future consultations;

- Detailed information on each impact to any First Nation's asserted title and rights that had been identified, either by the First Nation or through studies related to the project (such as archaeological studies or Traditional Use Studies);

- Information on how the severity of the impact was assessed and whether First Nations were involved in assessing the severity of the impact;

- Mitigation measures that had been identified by the proponent and whether those mitigation measures addressed First Nations concerns;

- In respect of permits that have not yet been issued by Crown agencies, identification of any concerns raised by First Nations in the permitting process; and

- Identification of all permits, licenses, tenures and approvals that had been rejected due to lack of adequate First Nations consultation.

Consultation Activities

The following documentation relating to First Nations consultation for the project:

- Consultation reports and consultation logs;
- Meeting minutes or records;
- Impact benefit agreements, memoranda of understanding, protocols or similar agreements with First Nations that validated the proponent's consultation;
- Information on how any commitments to First Nations have and/or would be undertaken;
- Letters of support or objection from First Nations;
- Correspondence between the proponent and First Nations;
- Band Council resolutions or similar authorizations; and
- Permits obtained from Crown agencies and correspondence between the proponent and Crown agencies concerning First Nations issues.

For the 25 awarded EPAs, BC Hydro determined that the consultation processes to this stage were reasonable and adequate.

5. NEED FOR CLEAN POWER CALL

a) Products

Firm Energy

BC Hydro pays for the firm energy that is received at the price in the EPA for that year multiplied by a time-of-delivery factor to account for the value of energy to BC Hydro at different time periods in a month and for different months in the year. The three by twelve (three time periods per month by 12 months) time-of-delivery factors are common to all EPAs.

The Super-Peak period is from hours 16:00 to 20:00, and the Peak period is from 6:00 to 16:00 and from 20:00 to 22:00 from Monday to Saturday. The Off-Peak period is from 22:00 to 6:00 from Monday to Saturday and includes all hours on Sundays and B.C. statutory holidays.

Table 5-3: Time of Delivery Factors

	Super-Peak [%]	Peak [%]	Off-Peak [%]
January	141	122	105
February	124	113	101
March	124	112	99
April	104	95	85
May	90	82	70
June	87	81	69
July	105	96	79
August	110	101	86
September	116	107	91
October	127	112	93
November	129	112	99
December	142	120	104

Non-Firm Energy

In addition to the firm energy being acquired under the Clean Power Call, BC Hydro will be purchasing approximately 800 GWh/year of non-firm energy which represents about 20 per cent of the total energy deliveries. Payment for any non-firm energy delivered is based on two pricing options provided to proponents. At the time of proposal submission, proponents elected to be paid for their non-firm energy deliveries based on either a fixed price schedule (Option A) reflecting BC Hydro's forecast of market electricity prices or a variable price (Option B) based on actual average spot market prices (Mid-Columbia) for non-firm energy.

Environmental Attributes

"Environmental Attributes" are another product BC Hydro is acquiring as part of the Clean Power Call. The term "Environmental Attributes" is broadly defined in Appendix 1 of the Specimen EPA to include all rights and benefits of any kind associated with, or airing from, a project's "greenness", including any green marketing attributes, offsets, credits or other instruments or rights arising from the actual or assumed displacement by the project of offsite emissions, as well as any offsets, credits, allowances or other tradeable rights arising from on-site emission reductions.

There are strong reasons for BC Hydro to acquire the Environmental Attributes from IPPs as part of the Clean Power Call:

- Most importantly, BC Hydro is not acquiring clean or renewable electricity if it purchases electricity without the Environmental Attributes. Such electricity would be considered as "null" electricity[8] in most jurisdictions since it no longer has any associated environmental benefits.

- There is a potential GHG liability from acquiring null electricity stripped of the Environmental Attributes because null electricity may have some GHG intensity, whereas clean electricity has no or very low GHG intensity.

- The acquisition of Environmental Attributes as part of a clean, renewable power acquisition process is consistent with procurement/acquisition processes of other utilities. With the exception of United States (U.S.) jurisdictions issuing standard offer-like acquisition processes under the *Public Utility Regulatory Policies Act* of 1978, for those jurisdictions for which information could be obtained, the Environmental Attributes are transferred to the purchasing utility;[9]

- Acquisition of the Environmental Attributes permits BC Hydro to manage risk in the event that at some point a Renewable Portfolio Standard is set for BC Hydro.

Environmental Attributes acquired through the Clean Power Call may be marketed to buyers in B.C., the Western Electricity Co-ordinating Council (WECC) region and other markets for the benefit of BC Hydro's ratepayers. BC Hydro's assumption is that the Environmental Attributes could generate between $3/MWh and $18/MWh if sold in the WECC region.

b) Need for New Resources

The need for energy from the Clean Power Call EPAs must be considered with respect to BC Hydro's load/resource balance and future resource requirements.

Energy Load/Resource Balance – Existing and Committed Resources

The load/resource balance for the early portion of the planning horizon based on existing and committed resources, net of Demand Side Measures (DSM), is provided in Table 5-1. For clarity, these figures do not reflect any supply-side resources that have not been fully committed. It shows that substantial resource additions are required with a resource gap of 600 GWh in F2013 growing to 4,100 GWh in F2017.

Table 5-1: Energy Load/Resource Balance for Existing & Committed Resources

(GWh/year)	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
Energy Gap	-600	-900	-1400	-1900	-4100	-4700	-5300	-5300

The following considerations are relevant to the energy load/resource balance:

- BC Hydro used its 2009 mid Load Forecast. The 2009 Load Forecast follows the same methodology as the 2008 Load Forecast presented in the 2008 LTAP. Before DSM, the 2009 Load Forecast is lower than the 2008 Load Forecast in the early years primarily due to lower transmission and general service customer sales forecasts. For example, the 2009 Load Forecast is down 214 GWh/year in F2017 when compared to the 2008 Load Forecast. However, stronger expectations for future oil and gas activity and new mining loads drives the 2009 Load forecast higher in the later years;
- DSM is based on the DSM Plan as set out in the 2008 LTAP Evidentiary Update.[10] In the 2008 LTAP, BC Hydro concluded that the DSM Plan included all the DSM that it could cost-effectively plan to acquire at this time;
- Burrard's firm energy contribution is zero as a result of Direction No. 2 to the BCUC;
- The Waneta Transaction's contribution of 865 GWh/year of firm energy is included;[11]
- The 2,500 GWh/year of non-firm energy/market allowance is included up to December 31, 2015; thereafter, such energy supply is not used for planning purposes in order to achieve self-sufficiency by 2016 and beyond; and
- None of the 3,000 GWh/year insurance called for in the 2007 Energy Plan or subsection 6(2)(b) of the *Clean Energy Act* is included. If the insurance requirement is added to the load/resource balance figures, the energy gap would increase considerably by F2021, or sooner if the additional 3,000 GWh is acquired on a phased basis.

BC Hydro's Current Power Acquisition Processes

BC Hydro has two other power acquisition processes underway – the Bioenergy Phase 2 Call and the Integrated Power Offer (IPO).

The Bioenergy Phase 2 Call is a competitive RFP for larger-scale biomass projects. Any form of biomass will be eligible, including wood waste sourced from new forest tenure enabled through sections 13 to 36 of the *Emissions Standards Act* enacted in May 2008. The RFP for the Bioenergy Phase 2 Call was issued on May 31, 2010. The target is to acquire up to 1,000 GWh/year (pre-attrition) or 700 GWh/year (post-attrition using a 30 percent attrition factor) of cost-effective energy.

BC Hydro launched the IPO for those pulp and paper customers eligible for funding under the Federal Government's $1 billion Pulp and Paper Green Transformation Program (GTP) which was introduced in June 2009. The GTP supports innovation and investment in areas such as energy efficiency and renewable energy production technologies. BC Hydro is taking an "integrated offer" approach with its eight pulp and paper customers which are eligible for GTP funding. The IPO will capitalize on the synergies presented when energy efficiency savings and electricity generation opportunities are considered together. BC Hydro estimates that the IPO will result in approximately 1,200 GWh/year (pre-attrition) or about 1,080 GWh/year (post-attrition using a 10 per cent attrition factor) of cost-effective energy.

Energy Load/Resource Balance with Bioenergy Phase 2 Call and IPO Projects

Table 5-2 shows the energy load/resource balance taking into account the estimated Bioenergy Phase 2 Call and IPO initiatives. Even with the addition of these resources, there is a gap of approximately 2,300 GWh/year (without insurance) in F2017. The 3,266 GWh/year of firm energy being purchased under the Clean Power Call equates to 2,286 GWh/year on a post-attrition basis assuming a 30 per cent attrition factor. Thus, the Clean Power Call EPA awards will allow BC Hydro to be largely in energy balance in F2017, effectively achieving self-sufficiency by calendar 2016.

Table 5-2: Energy Load/Resource Balance after Bioenergy Phase 2 Call and IPO

(GWh/year)	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
Energy Gap	200	200	100	-100	-2300	-3000	-3600	-3700

As shown in Table 5-2, there is a need for energy from the Clean Power Call as well as the Bioenergy Phase 2 Call and the IPO. Furthermore, there is still an energy shortfall of 700 to 1,400 GWh during F2018-20 which will be exacerbated with the need to acquire insurance volumes on or before the mandated 2020 timeframe.

[8] See, for example, the Western Climate Initiative's position set out in "*Electricity Subcommittee Discussion Paper on Renewable Portfolio Standards, Renewable Energy Credits and GHG Accounting*" (8 December 2008), page 1.

[9] See, for example, Ontario's Feed-In Tariff Program, enacted under the Ontario *Green Energy and Green Economy Act, 2009*, pursuant to which IPPs must transfer environmental attributes arising from projects to the purchasing entity, the Ontario Power Authority.

[10] Exhibit B-10 in the 2008 LTAP BCUC proceeding; annual values for energy are set out in Table 2-10 of the 2008 LTAP Evidentiary Update. The DSM numbers have been adjusted for base year savings achieved for the first 10 years (F2010 to F2019).

[11] Pursuant to BCUC Order G-12-10, dated 3 February 2010.

6. COST-EFFECTIVENESS

As identified in previous sections of this Report: (1) BC Hydro has a requirement for firm supply throughout its planning horizon and (2) the B.C. Government has placed significant importance, at a policy level, on acquisition of clean, renewable electricity. No comparisons are made with electricity that may be available in external power markets such as Mid-Columbia since post-2015 the BCUC is precluded from permitting BC Hydro to rely on such electricity sources pursuant to Special Direction 10.

a) Competitive Process

BC Hydro relies on the competitive Clean Power Call process as the primary support for its position that the EPAs are cost-effective. The BCUC previously found that an important determination of cost-effectiveness is whether or not the particular power acquisition process awards were the outcome of a competitive process that yielded a cost-effective result. In its Decision on the Call for Tenders for Capacity on Vancouver Island,[12] the BCUC stated:

> … once a competitive market-based process has been undertaken and firm commitments from bidders have been obtained, a competitive process should, in most circumstances, be accepted as persuasive evidence of the cost-effectiveness of the resultant successful bid.

BC Hydro notes that the volume of EPA awards – at 3,266 GWh/year – represents an acquisition of less than 20 per cent of the energy that was presented in proposals received. The following facts support BC Hydro's view that the Clean Power Call was a competitive, fair and transparent process:

- **Participation** – This was at a high level. As described in Section 3 of this Report, in November 2008 BC Hydro received 68 proposals from 43 proponents, representing more than 17,000 GWh/year of firm energy. Many of the participants were well-established industrial firms in B.C. and/or well-established and qualified IPPs.

- **Terms and Conditions Review** – In designing the Clean Power Call, BC Hydro sought First Nations, government agency, financial advisor, proponent and other stakeholder input to ensure the terms would not unduly discourage participation while at the same time providing adequate assurance to BC Hydro and its ratepayers regarding delivery commitments. BC Hydro is of the view that potential proponents and other stakeholders had ample opportunity to comment not only on the proposed process but also on the draft documentation (see Section 4 of the Report). Furthermore, BC Hydro retained Deloitte & Touche LLP to conduct a term sheet review in spring 2008 which identified potential issues and opportunities related to pricing and value-for-money.

- **RFP Process** – The RFP offered contract term and COD flexibility (both initial COD and the opportunity for phased COD) and hourly and seasonally firm energy options. In addition to the options set out in the RFP documents, proponents were allowed to propose variations to the Specimen EPA included in their contract price (an essential variation) or as an option that BC Hydro could chose to incorporate if it had value (a value variation). BC Hydro utilized the discretion inherent in an RFP process to negotiate price as well as both essential variations and value variations with proponents. In addition, BC Hydro could and did propose variations to the proposals that increased their value to BC Hydro and ratepayers.

- **Least Cost** – The awarded EPAs were among the least cost of the proposals and were considered to be cost-effective.

- **Consistency with Expectations** – The cost of the electricity acquired from the EPAs is in line with BC Hydro's expectations. BC Hydro estimated the cost of new long-term firm energy supply in the 2008 LTAP proceeding as \$124/MWh in 2008 constant dollars (or \$129/MWh in 2010 dollars using 2.1 per cent CPI escalation). This estimate represents the average real levelized cost to deliver firm energy to the load centre in the Lower Mainland including: (a) adjusters for transmission infrastructure costs and losses; (b) a capacity credit for resources that could provide an hourly firm energy product; (c) a relative valuation of energy acquired at different times of the year.

b) Comparison to Other Processes

In addition to its reliance on the competitiveness and transparency of the acquisition process, BC Hydro compared the awarded EPAs with the following:

- The unsuccessful Bioenergy Phase 1 RFP bidders;
- The clean, renewable power acquisition processes of other jurisdictions in North America;
- The Unit Energy Cost (UEC) data from the 2008 LTAP Resource Options Update for a 250 MW CCGT.

BC Hydro submits that these comparisons further indicate that the Clean Power Call EPAs are cost-effective.

Comparison to Bioenergy Call Phase 1 RFP

The levelized adjusted bid prices for the 14 unsuccessful Phase 1 RFP bidders range from $119/MWh to $395/MWh (see Table 6-1).

Given that the project submitted by the lowest cost unsuccessful proponent was assessed as having an overly high risk of not being developed, the relevant price range for the comparison of the EPA awards is $136/MWh to $395/MWh. All of the awarded Clean Power Call EPAs are below the price range offered by unsuccessful Bioenergy Phase 1 RFP bidders.

Table 6-1: Bioenergy Phase 1 RFP – Unsuccessful Proposals

Proposal	Offered Firm Energy Price at Plant Gate ($/MWh)	Levelized Plant Gate Price ($/MWh)	Levelized Adjusted Bid Price ($/MWh)
C	112	111	119
G	135	134	136
H	137	127	139
I	138	151	149
J	144	147	162
K	158	171	178
L	169	185	192
M	150	183	193
N	201	187	205
O	175	193	208
P	179	200	214
Q	182	203	217
R	195	230	252
S	194	217	328
T	300	365	395

Comparison with Other Jurisdictions

Many jurisdictions in the U.S. and Canada carry out acquisition processes for green or renewable power. Table 6-2 summarizes comparable renewable power acquisition processes in North America that have been either completed or launched since 2007.

The levelized energy prices for comparable calls in other jurisdictions vary from $79 to $176 per MWh (Canadian 2009$). As shown in Table 3-4, the levelized energy price for the Clean Power Call EPAs is $101/MWh for total energy and $111/MWh for firm energy at the plant gate level. Given that these prices are at the lower end of the energy price range for other North American jurisdictions, BC Hydro is of the view that the awarded Clean Power Call EPAs are cost-effective.

Comparison with New Generic CCGT

In the 2008 LTAP, BC Hydro committed to comparing Clean Power Call EPA awards to a generic, green field 250 MW CCGT located in the Kelly Lake/Nicola region in the B.C. interior, adjusted for location and the requirement to completely offset all GHG emissions by the CCGT COD.[13] The average energy from a 250 MW CCGT would be 1,916 GWh/year assuming a 90 per cent capacity factor.

If BC Hydro were to acquire electricity from CCGTs sited in Kelly Lake, it would have to be supplied by IPPs to meet the requirements of Policy Action No. 13 of the 2002 Energy Plan.

Table 6-3 sets out the UEC of the generic 250 MW CCGT at a 6 per cent real discount rate, delivered to the Lower Mainland. BC Hydro notes the following:

- Cost Information – In contrast to the bidding price information upon which the Clean Power Call EPAs are based, the analysis set out below is based on the 2008 LTAP Resource Options Report, with a planning level cost estimate based on a cost uncertainty of +40/-10 per cent. There is thus less cost certainty with the 250 MW generic CCGT when compared to the EPAs.

Table 6-2: Comparison to Other Renewable Power Acquisition Processes

	Award or Launch Date	Target Size of Call	Stated Energy Price* ($/MWh)	Energy Price – Levelized** (2009Cdn.$/MWh)
Hydro-Quebec 2005 Wind-Generated Electricity CFT (awards)	May 2008	2,000 MW	$87	$93
Puget Sound Energy 2008 All-Source RFP (bids received)	July 2008	2,235 MW	Hydro: US$79–164 Wind: US$104–155	Hydro: $85–176 Wind: $112–166
Portland General Electric 2007 Renewables RFP (shortlisted bids – mostly wind)	December 2008	255 MW	US$85–110	$91–118
Ontario Power Authority Feed-In Tariff	March 2009	Open offer	Hydro: $122–131 Wind: $135–190	Hydro: $85–111 Wind: $115–163
Hydro-Quebec Wind CFT for Aboriginal and Community Projects	April 2009	500 MW	$125 ceiling	$125

* Stated prices are typically for total energy and reflect contractual plant gate levels.

** Assume Canadian dollar = $0.95 U.S. and annual inflation of 2 per cent.

- Variable Cost Uncertainties – There are significant variable cost uncertainties with respect to CCGTs when compared to clean, renewable resources such as the Clean Power Call EPAs:

    - Table 6-3 shows a number of natural gas and GHG price forecast combinations, ranging from High/High to Low/Low. This highlights the fact that there is significant natural gas and GHG price uncertainty associated with a CCGT when compared to clean, renewable resources such as the EPAs.

    - Natural Gas Price Forecast – BC Hydro retained the independent expert Black & Veatch (B&V) to re-weight the 2008 Natural Gas Price Forecast set out in the 2008 LTAP based on new developments such as shale gas potential. B&V re-weighted the forecast as follows: (1) High – now at 11% (was 53%); Medium – now at 43% (was 44%) and Low – now at 46% (was 2%).

    - GHG Price Forecast – BC Hydro continues to rely on the GHG price forecast set out in the 2008 LTAP, which results from an independent expert (Natsource LLP) and was accepted by the BCUC in the 2008 LTAP Decision.[14] The three GHG scenarios are as follows: (1) lowest cost Price Cap scenario (15 per cent probability); (2) mid cost Linked Markets scenario (60 per cent probability); and (3) highest cost Made in North America Aggressive scenario (25 per cent probability).

    - The result is that a CCGT at the weighted average natural gas price and GHG price scenario is about $98/MWh, compared to a previous weighted average natural gas price and mid GHG price scenario of about $118/MWh.

    - Contracting Uncertainties – BC Hydro also notes that there would be contracting uncertainties related to allocating the risks that exist with CCGTs.

    - Other Risks – Uncertainties associated with renewable energy credits, offsets and other mechanisms which are required to render CCGTs as green projects.

- No Environmental Attributes – The Clean Power Call EPAs provide value-added Environmental Attributes which are not available from CCGT resources.

In addition to the cost and contractual uncertainties set out above, in BC Hydro's view, a CCGT has limited relevance as a price benchmark, for the following reasons:

- The BCUC endorsed a clean, renewable call as part of the 2008 LTAP Decision. In BC Hydro's view, this means that CCGTs are not truly alternatives to the EPAs. BC Hydro placed far more weight on the clean, renewable price benchmarks set out above.

- There is significant B.C. Government policy uncertainty with respect to the role of natural gas as a fuel for electricity generation, particularly with respect to BC Hydro's integrated electricity system. Legal and policy decisions made by the B.C. Government cast doubt on the acceptability of new natural gas-fired generation as part of the BC Hydro integrated system.

Even if the B.C. Government supports BC Hydro acquiring electricity from CCGTs, there is significant development risk. A 250 MW CCGT would trigger the B.C. *Environmental Assessment Act* and an air emission permit pursuant to the B.C. *Environmental Management Act*, with the public being involved pursuant to the Public Notification Regulation. Emission of pollutants such as nitrogen oxides, sulphur dioxide and carbon monoxide would be examined, in addition to GHG emissions and provisions for offsetting the GHG emissions. Although GHG emissions are a global as opposed to local impact issue, BC Hydro's experience has been that local residents are sceptical of the argument that a GHG offset located outside the region or indeed outside B.C. is as effective in reducing GHG emissions.

Details of the 27 Clean Power Call projects selected for the award of electricity purchase agreements are available on BC Hydro's website at **www.bchydro.com/cleanpowercall**.

Table 6-3: Unit Energy Cost for Generic 250 MW CCGT

	High Gas High GHG	High Gas Mid GHG	Mid Gas High GHG	Mid Gas Mid GHG	Low Gas Low GHG	Weighted Avg. Gas Weighted Avg. GHG
UEC contribution from capital + OMA	$ 21.14	$ 21.14	$ 21.14	$ 21.14	$ 21.14	$ 21.14
UEC contribution from fuel	$ 93.27	$ 93.27	$ 59.07	$ 59.06	$ 48.52	$ 57.98
UEC contribution from GHG	$ 19.65	$ 11.53	$ 19.65	$ 11.53	$ 8.22	$ 13.07
UEC (equivalent to FEP)	$ 134.06	$ 125.95	$ 99.85	$ 91.74	$ 77.89	$ 92.18
CIFT adjuster	$ 1.95	$ 1.95	$ 1.95	$ 1.95	$ 1.95	$ 1.95
Loss adjuster	$ 5.27	$ 4.96	$ 3.94	$ 3.63	$ 3.09	$ 3.65
Lower Mainland hourly firm energy adjuster	$ (3.88)	$ (3.88)	$ (3.88)	$ (3.88)	$ (3.88)	$ (3.88)
Levelized AFEP	$ 137.40	$ 128.98	$ 101.87	$ 93.44	$ 79.06	$ 93.90
Levelized AFEP in 2010 $/MWh	$ 143.23	$ 134.45	$ 106.19	$ 97.41	$ 82.41	$ 97.89

[12] BCUC Order No. E-1-05, page 13
[13] 2008 LTAP, page 6-45, lines 10-16, Exhibit B-1 in the 2008 LTAP proceeding.
[14] *Supra*, note 1, page 29.

Appendix A

Summary Listing of Clean Power Call EPA Awards

Proponent Name	Project Name	Location	Region	Energy Source	Capacity [MW]	Firm Energy [GWh/year]
AltaGas Ltd.	Crowsnest Pass	Sparwood	East Kootenay	waste heat	11	46
Box Canyon Hydro Corporation and Sound Energy Inc.	Box Canyon	Port Mellon	Lower Mainland	run-of-river	15	50
Castle Mountain Hydro Ltd	Benjamin Creek	McBride	Kelly Nicola	run-of-river	6	27
C-Free Power Corp.	Jamie Creek	Gold Bridge	Kelly Nicola	run-of-river	19	41
Cloudworks Energy Inc.	Big Silver-Shovel Creek	Harrison Hot Springs	Lower Mainland	run-of-river	37	110
Cloudworks Energy Inc.	Northwest Stave River	Mission	Lower Mainland	run-of-river	18	44
Cloudworks Energy Inc.	Tretheway Creek	Mission	Lower Mainland	run-of-river	21	56
CP Renewable Energy (B.C.) Limited Partnership (formerly EPCOR)	Quality Wind	Tumbler Ridge	Peace River	wind	142	434
Creek Power Inc.	Boulder Creek	Pemberton	Lower Mainland	run-of-river	23	48
Creek Power Inc.	North Creek	Pemberton	Lower Mainland	run-of-river	16	34
Creek Power Inc.	Upper Lillooet	Pemberton	Lower Mainland	run-of-river	74	143
ENMAX - Syntaris Bid Corp.	Culliton Creek	Squamish	Lower Mainland	run-of-river	15	56
Finavera Renewables Inc.	Bullmoose	Tumbler Ridge	Peace River	wind	60	142
Finavera Renewables Inc.	Meikle	Tumbler Ridge	Peace River	wind	117	327
Finavera Renewables Inc.	Tumbler Ridge	Tumbler Ridge	Peace River	wind	45	140
Finavera Renewables Inc.	Wildmare	Chetwynd	Peace River	wind	71	204
Pacific Greengen Power	Bremner / Trio	Harrison Hot Springs	Lower Mainland	run-of-river	45	148
Kwagis Power Limited Partnership	Kokish River	Port McNeill	Vancouver Island	run-of-river	45	183
Long Lake Joint Venture	Long Lake	Stewart	North Coast	storage hydro	31	139
NI Hydro Holding Corp. (representing Stlixwim entities)	Ramona 3 + Chickwat Creek + CC Creek	Sechelt	Lower Mainland	run-of-river	45	198
Plutonic Power Corporation and GE Energy Financial Services Co.	Upper Toba Valley	Powell River	Lower Mainland	run-of-river	124	214
Run of River Power Inc.	Mamquam	Squamish	Lower Mainland	run-of-river	25	68
Sea Breeze Energy Inc.	Knob Hill Wind	Port Hardy	Vancouver Island	wind	99	281
Selkirk Power Company Ltd.	Beaver River	Golden	East Kootenay	run-of-river	44	86
Swift Power Corp.	Dasque-Middle	Terrace	North Coast	run-of-river	20	46
Total					1,168	3,266

Appendix B

Dated: June 7, 2010

**INDEPENDENT OBSERVER'S REPORT
ON BC HYDRO CLEAN POWER CALL**

I was invited in October of 2008 to respond to a Request for Proposals from BC Hydro to act as an Independent Observer for BC Hydro's Clean Power Call. My proposal was accepted by BC Hydro and I have been performing the services of a Fairness Monitor / Independent Observer to the Clean Power Call from November of 2008 to the present time.

In my role as Independent Observer / Fairness Monitor I have reviewed in detail the Request for Proposals issued on June 11, 2008 and numerous other documents related to the RFP. Additionally, I have received and reviewed documentation exchanged between various proponents and BC Hydro during the process of evaluation of the various proposals received, and I have attended numerous meetings with representatives of Hydro alone and with representatives of Hydro and representatives of proponents on various occasions to monitor the evaluation process and, where applicable, report on and assist in the resolution of potential fairness issues.

At the outset of the Clean Power Call process, certain "listed" proponents were identified, being those proponents who had on their team individuals with previous significant relationships with BC Hydro. The evaluation of these proponents was monitored particularly closely. I was given access to all documentation relating to each of these proponents and attended most meetings held between these proponents and representatives of BC Hydro during the evaluation process.

During the course of the foregoing activities, my role was to observe the process during the course of meetings and in the exchange of correspondence to assure as far as practicably possible that the guidelines and terms and conditions set out in the RFP were followed and applied equally and fairly in the case of all proponents, and particularly in the case of the listed proponents. My involvement in this regard has included being kept fully informed of the evaluation of those proposals which have resulted in or are likely to result in the award of energy purchase agreements.

In the result, I have observed a very comprehensive and robust process in the receiving, assessment, and evaluation of the proposals received in response to the Clean Power Call and, in my opinion, the process has been fair, transparent and without any demonstrated bias being shown towards any particular proponent. Additionally, I have observed a keen awareness and commitment by those responsible for administering the process and evaluating the proposals to the requirements of the RFP and the Evaluation Guidelines and generally to the need to bring fairness to the process at all levels.

RESPECTFULLY SUBMITTED,

John R. Singleton, Q.C.

GENERAL/50238.345/725122.1

Attachment 218.3.1.1

[redacted]

[redacted]

208.5 Is the FEU aware of any other jurisdictions that use the cost of biomethane as the avoided cost in DSM program cost effectiveness screening?

Response:

No, the FEU are not aware of any other jurisdictions that use the cost of biomethane as the avoided cost in DSM program cost-effectiveness screening. FEI is the one of only a few utilities in North America to offer biomethane as a supply option, so the fact that biomethane is not used in other gas utility screen tests is not unexpected.

208.5.1 What do other jurisdictions do to address the volatility of natural gas prices in their DSM cost effectiveness screening? What are other jurisdictions doing to address the low price of natural gas in their DSM cost effectiveness screening?

Response:

The Companies are aware that other gas utilities are wrestling with the challenges posed to natural gas DSM activity by low natural gas commodity prices; however, there are no published opinions or guidelines in other jurisdictions to the Companies' knowledge regarding addressing the role of gas price volatility in cost-effectiveness analysis. There is some anecdotal evidence of a movement toward addressing this issue by using the planning avoided costs as the baseline for evaluation during the plan period. For example, utilities in Iowa file updates to their DSM plan using avoided costs from the DSM plan initially submitted to the Regulator. Similarly, Piedmont Natural Gas in North Carolina provided cost-effectiveness results using the avoided costs used for program planning at the outset of program launch for an evaluation filed last year. Piedmont also provided an additional cost-effectiveness scenario in that evaluation using current avoided costs that were lower than the original planning avoided costs to demonstrate gas price sensitivity. The FEU's consultants have conducted informal interviews with other gas utilities' DSM managers; those interviewees have stressed the importance of understanding the effects of gas price volatility and low natural gas commodity prices on benefit-cost analysis.

208.6 Please discuss alternatives to using the price of biomethane to reduce the volatility of natural gas prices used in DSM cost effectiveness screening. For example could a multi-year rolling average of natural gas prices be used as the avoided cost?

Response:

In the 1970 and 80's the primary objective of DSM was to balance investment in energy supply and demand and hence reduce the cost of meeting the energy services needs of the economy. However, over time the objective of DSM programs has shifted to providing more environmentally benign energy rather than just the lowest cost energy services.

Many jurisdictions world-wide such as Ontario, the EU, Australia, China, Iran, Israel, and South Africa have added higher "feed-in" tariffs for alternate energy such as photovoltaic or wind power. The issue then arises of whether DSM should be screened against the marginal sources of "conventional" supply or against these higher-cost more benign energy sources. As DSM is typically the most environmentally benign way to meet the energy service needs of an economy, it makes sense to screen DSM programs against these alternate energy options that share similar environmental characteristics.

This change in emphasis away from lowest cost energy services is also reflected in BC Hydro's renewable portfolio standards. The requirement for 93 percent renewable/clean electricity supply provides benign energy but imposes higher marginal costs on new energy supply.

In the case of the FEU, the best proxy for a benign gaseous fuel is biomethane. However another proxy for an appropriate cost for a benign fuel could be to use the above mentioned BC Hydro renewable portfolio standard as it has been accepted as a socially acceptable price for a benign fuel.

One of the fundamental differences between BC Hydro's marginal cost for electricity and FEU's marginal cost for natural gas is that the marginal cost for electricity is based on the cost of producing electricity from an project whether that be an IPP or a major hydro electric project such as Site C. This cost tends to be stable over time as it is driven by a series of projects with long expected economic lives.

However the marginal cost of natural gas is based on various estimates of what the supply and demand for natural gas will be for multiple years in the future and is subject to much greater uncertainty and fluctuation. This fluctuation poses challenges to natural gas DSM benefit-cost analysis as in periods of high natural gas prices, the amount of DSM that appears to be "cost-effective" is greater than the amount of DSM that appears to be "cost-effective" during periods of lower natural gas prices, such as the period that we are currently in. The DSM marketplace, however, needs stable utility DSM funding in order to make the investments that support market transformation. Thus the FEU are proposing to use the ceiling price of biomethane as the appropriate avoided cost input to benefit-cost analysis, as it is more stable than commodity rates for natural gas as determined by the open marketplace for natural gas commodity, and because biomethane shares DSM's "green" environmental attributes. The suggestion of using a multi-year rolling average doesn't address this uncertainty of forecasting supply and demand conditions many years into the future.

It should be noted that the definition of the Societal Cost Test contained in the California Standard Practice Manual allows the use of higher marginal costs if its costs are lower than other utilities in the state or than its out-of-state suppliers[50]. Applying the same logic to marginal costs of alternate energy appears to be a reasonable extension of the principle.

[redacted]

[50] P19, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", July 2002

[redacted]

208.7 The FEU state "using the avoided cost of biomethane or an efficiency-adjusted cost for "green" electricity in the benefit-cost test recognizes the typically higher cost of "green" energy sources such as biogas, electricity and DSM." Does the FEU believe DSM should cost more than supply side resources? If so, why?

Response:

It is the Companies' view that as an environmentally benign alternative to conventional sources of new supply, DSM should be analyzed by applying an avoided cost that is representative of the cost of environmentally benign new supply, rather than conventional new supply. The failure of some DSM measures to pass the TRC screen using an avoided cost for conventional natural gas tells us that in the current environment of relatively low natural gas commodity prices, some DSM measures do cost more than conventional supply side resources. DSM, however, is significantly "greener" than conventional supply side resources, and using the ceiling price of biomethane as the avoided cost recognizes the "green" attributes of DSM.

208.8 With respect to biomethane as the avoided cost of gas, please further explain the meaning of "efficiency-adjusted cost of 'green' electricity."

Response:

The "cost of 'green' electricity" refers to the second tier of the BC Hydro Residential Inclining Block Rate. As stated in the Biomethane Application, the FEU believe that this is the closest thing to a proxy for the price of green energy in the Province. The "efficiency-adjusted" term refers to the assumption that the average efficiency of an electric appliance is close to 100 percent whereas the average efficiency of a gas appliance is approximately 90% and, as such, comparing usage rates between the two forms of energy requires an adjustment for efficiency.

Attachment 219.5

4. Reference: Exhibit B-1, p.47

Terasen Utilities have identified the key principles that guided the selection of particular EEC initiatives and programs within the application.

The EEC application states that a key principle is that "EEC expenditures will be efficient, with non-incentive costs not exceeding 50% of the expenditure in a given year."

The EEC application also states that a key principle is that "Programs will have market transformation as their ultimate goal, and program plans will describe how a program will contribute to market transformation."

4.1 Does Terasen Utilities agree that a number of barriers, including awareness, availability, accessibility, affordability and acceptance, impede energy consumers from taking advantage of cost-effective energy efficiency opportunities?

Response:

Yes, the Terasen Utilities do agree that these barriers impede energy consumers from taking advantage of cost-effective energy efficiency opportunities.

4.2 Does Terasen Utilities agree that in pursuing the goal of market transformation, effective program designs will target whichever barriers are prevalent for the targeted market segment and energy efficiency opportunity?

Response:

Yes the Terasen Utilities do agree that in pursuing the goal of market transformation, effective program designs will target whichever barriers are prevalent for the targeted market segment and energy efficiency opportunity.

4.3 In the future, can Terasen Utilities foresee a situation where the barriers to energy efficiency other than affordability would be sufficiently significant such that, in pursuing the goal of market transformation, a program's non-incentive costs would need to be greater than 50% of program expenditures in a given year?

Response:

Within the portfolio of EEC activity outlined in the Application, the goal of the Companies' would be to keep non-incentive costs at less than 50% of program expenditures. It is difficult to speculate for future portfolios, but it is possible that in the future, in pursuing the goal of market transformation, a program's non-incentive costs may need to be greater than 50% of program expenditures in a given year.

Attachment 220.5

210.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-1, pp. 20-21

Recognition of Spillover Effects in Net-to-Gross Ratio

" …it is important to attempt to capture additional energy savings from spillover…."

210.1 Does the FEU have a specific proposal to quantify additional energy savings from spillover effects? If so, please provide the proposal in detail.

Response:

No, the FEU do not have a specific proposal to quantify additional energy savings from spillover effects. The FEU would evaluate program effects on a program-by-program basis, using consultants to conduct surveys of program participants and non-participants, to determine both free rider rates and spillover effects. As noted during the original EEC proceeding in 2008, in which the Companies proposed to use gross energy savings to calculate benefit-cost results, free rider rates are notoriously subjective. Spillover rates are the same in that they are primarily determined by surveying individuals as to the effect that a utility DSM program has had on the respondent's actions, generally a significant amount of time after the action has been undertaken. It is the view of the Companies, however, that by not accounting for program spillover effects, and only adjusting program results downward for free rider effects, evaluation of the Companies' programs is creating a lopsided view of the Companies' EEC activity.

210.2 Is the FEU aware of other natural gas utilities where spillover effects are included in net to gross (NTG) calculations? Please provide the list of natural gas companies and the period of time such spillover effects were incorporated in the NTG analysis.

Response:

There are some natural gas utilities where spillover effects are included in NTG calculations. National Grid, for example, in Masschusetts, incorporates spillover in its NTG calculations[74]. BC Hydro also incorporates spillover effects in NTG calculations.[75] Florida, Illinois, Massachusetts,

[74] `Source: http://www.ma-eeac.org/docs/MA%20TRM_2011%20PLAN%20VERSION.PDF, pp 16 - 20

[75] `Source: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/rev_req/directive_66_summary_report.Par.0001.File.2008_04_11%20DSMMES%20RPT.pdf

New York and Oregon include spillover effects, while California, Wisconsin and Connecticut do in some cases.[76]

The Companies were not able to determine the period of time such spillover effects have been incorporated into the NTG analysis in each jurisdiction, however on a practical level, this would be on a program-by-program basis, depending on the nature of the program.

210.3 Does the FEU anticipate issuing a request to deem NTG ratios for all programs, including Innovative Technologies programs and New Initiatives? If so, please provide the proposed deemed values for:

i. Freeriders
ii. Spillover
iii. Realization rates

Response:

The Companies have not requested deemed NTG ratios at this time, and as such have not determined deemed NTG ratios for free riders, spillover or realization rates, however this is certainly one approach to NTG ratios. Deeming NTG ratios could result in reduced costs for ratepayers, as highly costly evaluation studies could potentially be reduced. Deeming NTG ratios is one approach to the high uncertainty around free rider rates and spillover. Another approach, and one which the Companies put forward in the original EEC proceeding in 2008, is to accept that both free riders and spillover are highly uncertain, that they cancel each other out, and that the appropriate approach is to use gross energy savings as the benefit. Please refer to Attachment 210.3, which includes a paper, "Maximizing Societal Uptake of Energy Efficiency in the New Millennium: Time for Net-to-Gross to Get Out of the Way?", makes the case that for California to meet their climate change goals of reducing GHG emissions by 80 percent by 2050, transformative energy efficiency efforts will be required, that tap markets more broadly and deeply than current efforts have done, and that current evaluation methods that are focussed on free rider effects cause program administrators to focus on those programs based on measures that are easy to measure and verify, and undervalue resources spent on programs that have long lead times and high spillover effects.

[76] `Source: http://eetd.lbl.gov/ea/EMS/reports/lbnl-3277e.pdf, p 19.

210.3.1 If proposing to deem NTG, please provide the rationale for the components noted above and supporting documentation.

Response:

The Companies are not proposing to deem NTG at this time.

Attachment 225.5.1

FORTIS BC™

BUSINESS ETHICS POLICY

Statement of Commitment

FortisBC ("the Company") is committed to being a corporate leader in ethical practices and will maintain highly ethical standards in its activities, and fairness and honesty in its business relationships. All representatives of the Company must observe the highest standards of business and personal ethics while performing any duties on behalf of the Company. The Company will not tolerate any conduct by an employee, individual or group engaged in business activity on its behalf that is outside of the law or gives the appearance of impropriety or unethical conduct.

Principles of the Business Ethics Policy

- Doing what is right
- Respecting the rights of others
- Obeying the law
- Maintaining the integrity and confidentiality of information
- Avoiding conflicts of interest
- Conducting ourselves appropriately

Representatives of the Company must not only consider whether they are in compliance with this policy but also how their decisions and actions will appear to an outside party. The perception of wrongdoing is potentially as damaging as an actual breach of ethics. Therefore, it is essential that representatives not only conduct Company business according to high ethical standards but also be seen to do so.

Scope

This policy applies to all directors, officers and employees, contractors, vendors, agents and any other representatives ("personnel" or "representatives") of FortisBC while engaged in official business and involved with other activities that promote the objectives and interests of the Company.

This Policy is not intended to prohibit any ordinary business or social exchanges that occur in the course of business relations. The Company recognizes the importance of good business relations and encourages networking with our vendors and customers. It is acceptable within the guidelines of this policy to accept meals and invitations of nominal value to events from vendors and to extend such courtesies to vendors and customers. Vendor sponsored events with a more than nominal value require VP approval prior to acceptance of the invitation. Irrespective of rewards or other incentives that may be offered, however, representatives of the Company are expected to conduct business in the most cost effective manner.

Definitions

Conflict of interest - any situation or activity where a representative's personal or private interests (including the interests of family members) affect, or can reasonably be perceived to affect, the discharge of the representative's obligations to the Company. An interest includes gifts, commissions, payments or loans greater than nominal value either to or from a vendor as well as product or service discounts from a vendor not widely offered to all personnel or across the industry. An interest also includes an employee's ownership of a vendor or a personal connection with a vendor that could give the perception of a conflict. Nominal value is defined as items of usefulness but of immaterial monetary value individually and collectively. Examples include inexpensive meals, event tickets, promotional gifts and published reward programs such as airline miles.

Confidential Information - any Company, employee, vendor or customer information that has been obtained or created within a trusted relationship and that would not ordinarily or explicitly be disclosed. Any information which has not been publicly disclosed should be treated as confidential.

Vendor - any unaffiliated person or firm that is an actual or potential supplier of services, materials or equipment to the Company.

Customer - any person or firm that is an actual or potential purchaser of services, materials or equipment from the Company.

Guidelines

The following guidelines are meant to provide representatives with an overview of the activities covered by this policy. The absence of guidelines covering other particular situations does not relieve representatives of their responsibility to use good judgment and act in a manner which exhibits the highest ethical standards to which FortisBC is committed.

1. Customers

All representatives will treat customers fairly, honestly, with courtesy and in good faith at all times. The Company's capabilities must not be misrepresented and there must not be any attempt to unfairly influence customer decisions relative to our products and services. Representatives must not accept any form of personal remuneration for any work performed by the Company on a customer's behalf. While performing duties for customers of the Company, representatives are prohibited from soliciting personal employment or business activities from those customers. Similarly, representatives are not permitted to recommend or refer customers to other businesses in which representatives have personal interests.

Customer relationships are critical to the continuing success of the Company. All representatives will respect and ensure the confidentiality and privacy of customer personal information unless disclosure is required by law or order of a regulatory agency. Representatives are expected to comply with the Company's Privacy Policy with respect to protecting the confidentiality and privacy of customer personal information to which they have access in the course of their employment.

2. **Vendors**
   Representatives dealing with outside vendors should carry out their duties free from any conflict of interest. Gifts or invitations with greater than nominal value must not be accepted. Representatives dealing with outside vendors must not personally request gifts, invitations or other forms of financial rewards, including discounted products or services that may explicitly or implicitly be considered in exchange for preferred vendor status. Vendor sponsored events with a more than nominal value require VP approval prior to acceptance of the invitation.

   Relationships with vendors must always be arm's length, consistent with accepted business practices, the Company's policies, and in accordance with applicable laws. In dealing with vendors, representatives will conduct themselves with fairness, courtesy and good faith. All interactions with vendors must conform to the requirements of the section of this policy addressing conflict of interest.

3. **Government or Regulatory Agencies**
   Representatives shall not directly or indirectly give, offer or promise anything of value to employees of government or regulatory agencies in an attempt to improperly influence their dealings with the Company.

4. **Company Records and Accounting Practices**
   All information held by the Company, whether for internal or external use, must be recorded and reported fairly and honestly. Prior to release, any disclosure or publication of confidential information must receive explicit approval from an appropriate Company official.

5. **Personal Use of Company Property and Data**
   The involvement of Company personnel or the use of equipment, facilities or data for business and/or activities other than Company business, community activities or other approved programs is prohibited. Users of Social Media streams are expected to adhere to Company policy.

6. **Compliance With This Policy**
   It is critical to the Company's success that all representatives conduct themselves ethically and legally in every aspect of their business activities. Every representative of the Company is required to comply with this Business Ethics Policy.

   Personnel in leadership positions must assume a responsibility for the actions and conduct of other employees who report to them. Supervisors and managers can fulfill this responsibility through prudent management practices such as:

   - Ensuring this Business Ethics Policy is clearly communicated to all reporting employees and Contractors on a regular basis;
   - Establishing and maintaining internal and management controls designed to prevent or detect breaches in corporate policies;

- Leading by example and exhibiting high standards of ethical behaviour;
- Appropriately investigating situations which may indicate a breach of this policy; and,
- Dealing with known breaches of this policy in an appropriate manner, including disciplinary action where warranted.

Compliance, both personal and by reporting employees / Contractors, will be a factor in Managers' and Supervisors' periodic performance reviews. Violations of this policy will result in the Company taking appropriate action, including possible discharge from employment. All personnel should also be aware that potential personal liability does not end with the discipline undertaken by the Company. Depending on the circumstances, an individual may also face civil or criminal charges and penalties (including imprisonment).

7. Reporting Violations

Anyone who reasonably believes a violation of this policy has occurred, including questionable financial reporting, safety violations, fraud, waste, abuse or internal control matters, has an obligation to report the violation promptly to an appropriate Company official. Possible violations should be reported to an appropriate supervisor in the employee's work area. However, where there is uncertainty as to how a violation of this policy should be reported, the reporter may consult with the Director, Internal Audit or any officer of the Company in confidence, or use the EthicsPoint hotline.

The EthicsPoint hotline is a confidential reporting tool that is managed by an independent entity and is available 24 hours a day, seven days a week. The Company encourages all representatives to use the EthicsPoint hotline to report any activity that may be a cause for concern. Anonymous reports can be made on line at **www.ethicspoint.com** or by calling **1-866-294-5534**. All reported information is secure and held in the strictest confidence. No report is ever shared with implicated parties, their peers or subordinates.

The Company will not take or allow any reprisal against a representative for, in good faith, reporting a suspected violation of this policy. Any such reprisal will in itself be considered a very serious breach of this policy and offenders will be subject to disciplinary action.

All reported violations will be investigated. Where an investigation determines that a violation has occurred, appropriate action will be taken.

Managers and Supervisors must report all breaches of this policy, including incidents of theft or fraud, to any officer of the Company, the Director, Internal Audit, or through the EthicsPoint hotline.

Effective Date

This policy is updated and effective as of July 28, 2011.

Procurement Policy

Replaces: CORP 02-06 dated 22 October 2009

Overview

The Procurement Policy applies to the acquisition of materials, equipment and services for FortisBC (Natural Gas) (FBC (Gas)), its affiliates and subsidiaries.

Audience

All FBC (Gas) employees involved in buying materials, equipment or services.

References

- CORP 01-04 Code of Business Conduct
- ADM 04-01 Authorization Levels
- FBC (Gas) Purchase Card Policy
- Corporate Credit Card User Guide
- BCUC Code of Conduct
- Ethical standards of the Purchasing Management Association of Canada

Scope

The following policy applies to the acquisition of materials, equipment and services for FBC (Gas), its affiliates and subsidiaries. Procurement activities include:

- market analysis and trends
- competitive and non-competitive bidding
- contract management
- negotiating
- researching
- sourcing
- developing and maintaining supplier relationships

- providing expertise
- using Purchase Orders, Blanket Orders and Service Contracts

FBC (Gas) authorized Procurement Agents perform these activities.

The procurement policy does not apply to the following contracts:

- Natural gas
- Land and Right-of-way
- Accenture Business Services for Utilities / Customer Works
- Legal, Regulatory or Finance
- Travel

Purpose

The purpose of the Procurement Policy is to ensure that all purchases of material, equipment and services that are processed through Procurement are performed in an ethical manner and in accordance with prudent business practices for the best overall value (focusing on quality, price, reliability, service, support, delivery, training and continuous improvement).

Guiding Principles

The Procurement Department shall adhere to the FBC (Gas) Code of Business Conduct and the ethical standards of the Purchasing Management Association of Canada.

The Procurement Department is managed by the FBC (Gas) Business and Information Technology Services (B & ITS) to ensure compliance to the BCUC Code of Conduct.

Authorized Agents

Upon receiving authorized requisitions from internal requestors, Procurement Agents will commit FBC (Gas) to the purchase of materials, equipment and/or services, regardless of whether the funding is expense or capital. All purchases that are processed through Procurement will be placed via Purchase Order or Blanket Purchase Order with an appropriate supplier by the Procurement Agent, except as allowed for by the FBC (Gas) Purchase Card Policy.

Additionally, Procurement Agents will conduct all price, terms and conditions negotiations with suppliers and will coordinate with the appropriate departments regarding technical specifications, performance requirements and finalize the contract documents. Exceptions to FBC (Gas) terms and conditions will be vetted through the Legal department. Any post-award changes to agreements must be documented by the Procurement Agent on the contract.

Employees not designated as Procurement Agents may obtain quotations on materials, equipment, or services for the purpose of preparing budgets, or clarifying technical requirements. Forward copies of any quotations obtained to the Procurement Department.

Low Dollar Commitments

Purchase cards can be used for materials and services under $10,000 as guided by the Purchasing Card Policy.

Please refer to the Corporate Credit Card User Guide for specific guidance on allowable and non-allowable purchases.

Any materials that must retain pressure when installed in natural gas transmission, distribution, and storage systems should not be purchased on a purchase card. The exceptions are:

- Materials required on an emergency basis. Emergency materials can be bought on a purchase card but must be signed off by an engineer
- Vendors who distribute approved manufactured parts and have been qualified by Procurement
- Swagelok fittings from Columbia Valve and Fitting

If a supplier does not accept credit card, the Local Order Contract (Form 1823) can be used to provide a commitment to the supplier. The requestor is responsible to approve the invoice for payment.

Bidding Policy

Materials or services requests over $10,000 are bid out competitively unless there is sufficient justification for a single/sole source arrangement or the expected outcome will be of greater corporate value than the competitive bidding process. Standard template terms and conditions will be used to support the bid package. The Procurement Department will liaise with Legal Services on behalf of our client to review and amend bid packages where there is significant risk related to financial, insurance, technology, environmental, safety and/or liability.

Project Construction and Consulting Services with Blanket Orders

Blanket contracts have been set-up by Procurement with select suppliers to expedite recurring project work. Please refer to the specific policy on the usage of these blanket orders. The blanket orders cover the following areas:

- Natural gas construction services
- Technical services
- Engineering services
- Non-destructive testing services
- Survey services

Any environmentally sensitive project requirements are not covered by this policy. These default to the standard bidding policy.

Single/Sole Source Policy

The following are conditions that apply to single/sole source scenario:

a) Work requested is a continuation of a previous uncompleted contract;

b) The vendor supplies a skill, product or intellectual capital that is not available elsewhere in the marketplace (e.g., the purchase of original equipment manufacturer (OEM) parts;

c) A negotiation strategy has been submitted and approved by Procurement and Senior Management that demonstrates how legal and commercial risk will be mitigated and the expected outcome will clearly be of greater corporate value than the competitive bidding process.

The sourcing justification must be documented in sufficient detail. The following questions should be addressed in the justification:

1. What are the unique performance **features** of the product or brand requested that are not available in any other product or brand? (For services: **What are the unique qualifications this vendor possesses**?) Identify specific, measurable factors/qualifications. You must state the technical and/or commercial characteristics, uniqueness, operational compatibility, or other pertinent information

that make it impractical or impossible to purchase through a competitive bidding process.

2. **Why are the unique features/qualifications required?**
3. **What other brands/services were evaluated, rejected and why?**
4. **Does the price being paid represent fair market value?** (Explanation and documentation required).

Convenience and/or expediency alone are not sufficient reasons to bypass the competitive bidding process.

The requestor must answer the sole source justification questions on the Request for Purchase Requisition form and have it approved by their Manager and/or asset owner, and forward it to the Procurement Department. The Procurement Manager will review and may challenge the justifications or request alternate approvals.

Roles and Responsibilities

All parties involved in the procurement process hold the following responsibilities:

1. Adherence to corporate ethical, environmental, legal and procurement policies;
2. Adherence to National Instrument (NI) 52-109 compliant business process and internal controls;
3. Timely data updates to support business events.

A. The End User (Requisitioner) is responsible for the following activities:

1. Compile detailed material specification, drawings, any required reference documents or scope of work and deliverables (reference to vendor's proposal is not acceptable);
2. Ensuring the specifications or scope of work complies with all governing laws plus FBC (Gas) internal policy and procedures;
3. Provide materials ordering information such as units, quality or testing requirements;
4. Provide service order information such as work objectives, deliverables, qualification or acceptance criteria;
5. Communicate requirements for insurance, bonds, builder's liens, holdbacks, incentives or penalties;
6. State where and when the materials or services are required;

7. Provide vendor quotes and other relevant back up material;
8. Provide a list of suggested bidders and reasons for excluding any potential bidder(s);
9. Document single/sole source justification where appropriate;
10. Communicate change orders to reflect requirement changes as they occur and BEFORE THE WORK IS DONE. The original Purchase Requisition will need to be revised and re-approved, and a subsequent change order issued;
11. Obtain appropriate SAP on-line requisition approvals as per ADM 04-01;
12. Acknowledge the receipt of goods delivered to field locations and communicate to Procurement in timely manner. If the purchase is for pressure bearing materials to be installed in a transmission or distribution system, the requisitioner is responsible for making certain that a quality inspection is performed upon material receipt to ensure that it is fit for service. Corporate policy is that this inspection must be performed by an individual with a materials engineering accreditation;
13. Approve invoices for service work.

B. The Legal Department is responsible for the following activities:

1. Monitor risk levels in FBC (Gas) purchases;
2. Provide legal advice on contractual matters;
3. Maintain standard templates for use by Procurement including tender documents, terms and conditions, etc.;
4. Create or review supplemental legal clauses for non standard tender documents, including terms and conditions.

C) The Environmental Health and Safety Department is responsible for the following activities:

1. Provide oversight on work involving environmental sensitivity, recycling, disposing of, or transporting dangerous or sensitive goods;
2. Recommend or review environmental clauses in the Request for Quotation (RFX) packages.
3. EHS may assist in determining the list of vendors to receive the RFX package when applicable. This may involve pre-qualifying contractors to ensure appropriate skills and compliance with environmental law and Work Safe BC.

D) Procurement Department is responsible for the following activities:

1. Provide process governance over procurement policy, expenditure authorization and internal controls;
2. Create the vendor selection criteria where applicable with input from the end user;
3. Manage the tendering process which includes preparing and sending RFX tender documents to the marketplace per Canadian bidding law;
4. Be the single point of contact for vendor information requests during the bidding process. Vendor questions will be forwarded by the Procurement Agent to the appropriate party for response;
5. Compile bid evaluations and provide recommendations;
6. Research financial viability of potential vendor;
7. Obtain executed (signed) copies of contracts;
8. Obtain executed (signed) copies of Purchase Orders (if required).

Timing of Requests

Requestors must factor adequate lead time into their purchasing plan to allow the Procurement Agents to do their jobs effectively. The business processes defined for Supply Chain have pre-determined turn around times and escalation procedures. Refer to the B & ITS Business Process Review (BPR) for detailed documentation.

Attachment 226.5.2

Keep the Change:
The Persistence of New Energy Behaviors

Kira Ashby, Program Manager
CEE Summer Program Meeting
Boston, MA
May 30, 2013

Agenda

- Welcome & Introductions
- Objectives and Background
- Presentations
  - Bruce Ceniceros, SMUD
  - Joel Smith, Puget Sound Energy
- Q&A
- Small Group Discussion
- Large Group Discussion

Introductions

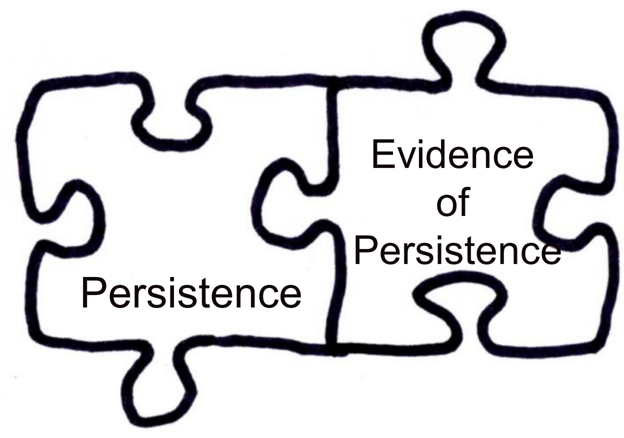
Today's Objectives

- Provide an overview of recent research on the persistence of EE behavior change
- Discuss lessons learned and caveats
- Share information on any other persistence research currently underway (or planned) and where gaps remain

Why does persistence matter?

Persistence impacts a program’s:

- Long-term effectiveness
- Ability to reach more customers
- Credibility
- Cost-effectiveness
- Ability to claim savings

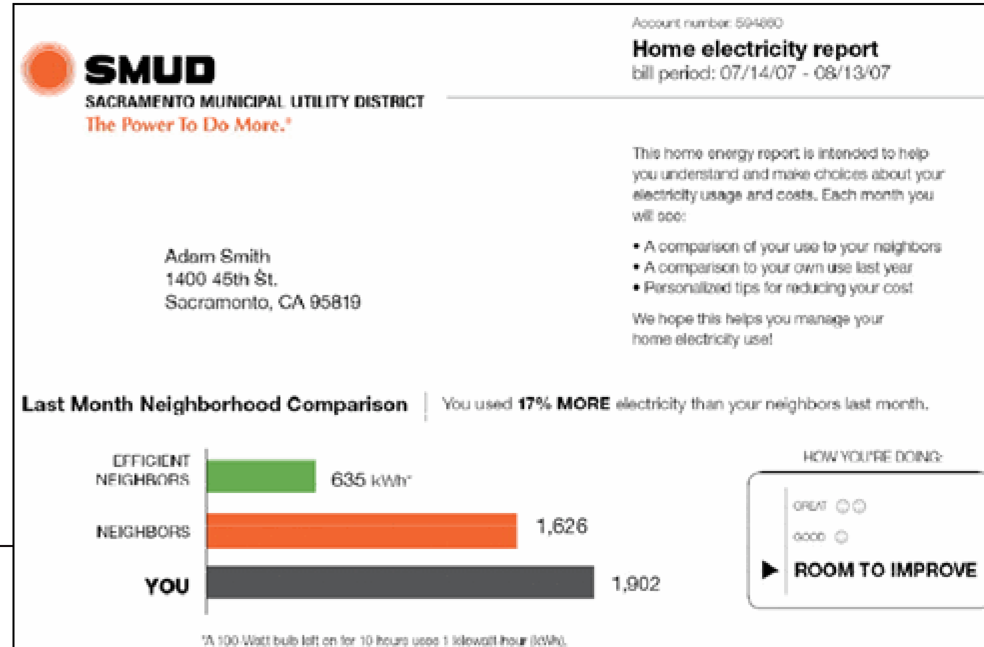


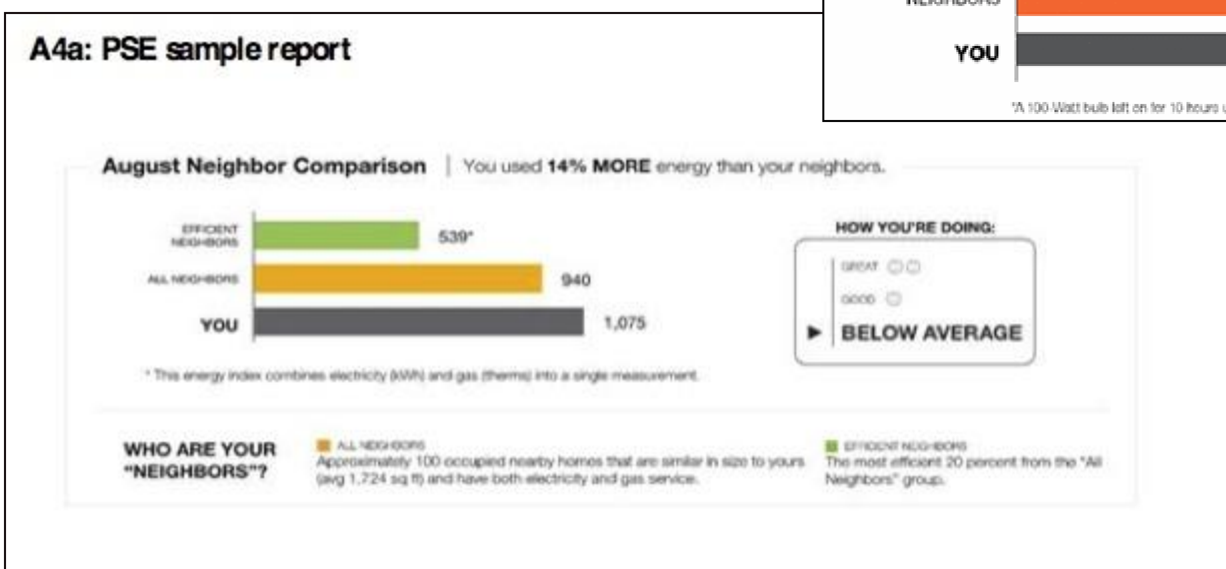
1 Program Type, 2 Case Studies

Program Type:
Home Energy Report Programs

Evaluation: Experimental Design

Program Examples:
- SMUD
- Puget Sound Energy





Presentations

- **Bruce Ceniceros**

  Sacramento Municipal Utility District (SMUD)

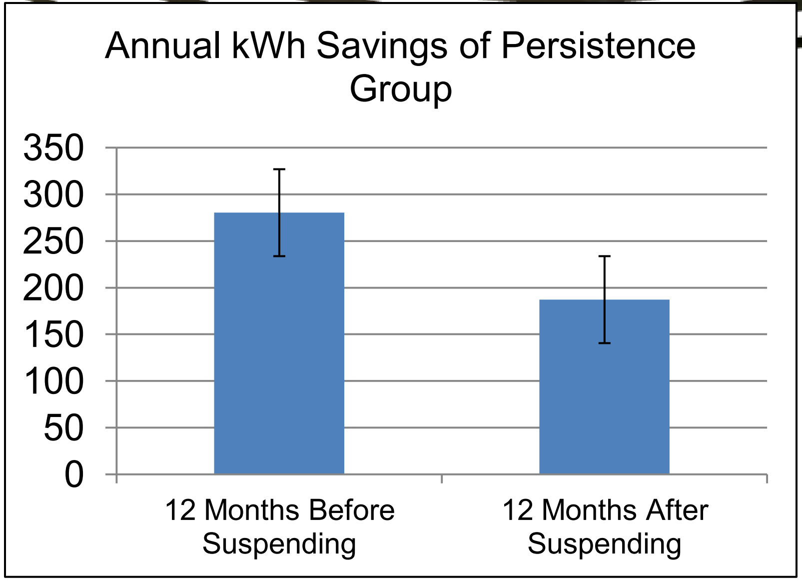
- **Joel Smith**, *presenting remotely*

  Puget Sound Energy (PSE)

Persistence of Savings for Home Energy Reports

Bruce Ceniceros
Principal Demand Side Planner
Sacramento Municipal Utility District

SMUD™



Relevant research questions

- How well do savings hold up over time?
- How much savings persists after reports are stopped?
- What actions account for the savings?
- How much of savings is from behavior versus equipment?

Treatment groups and sizes

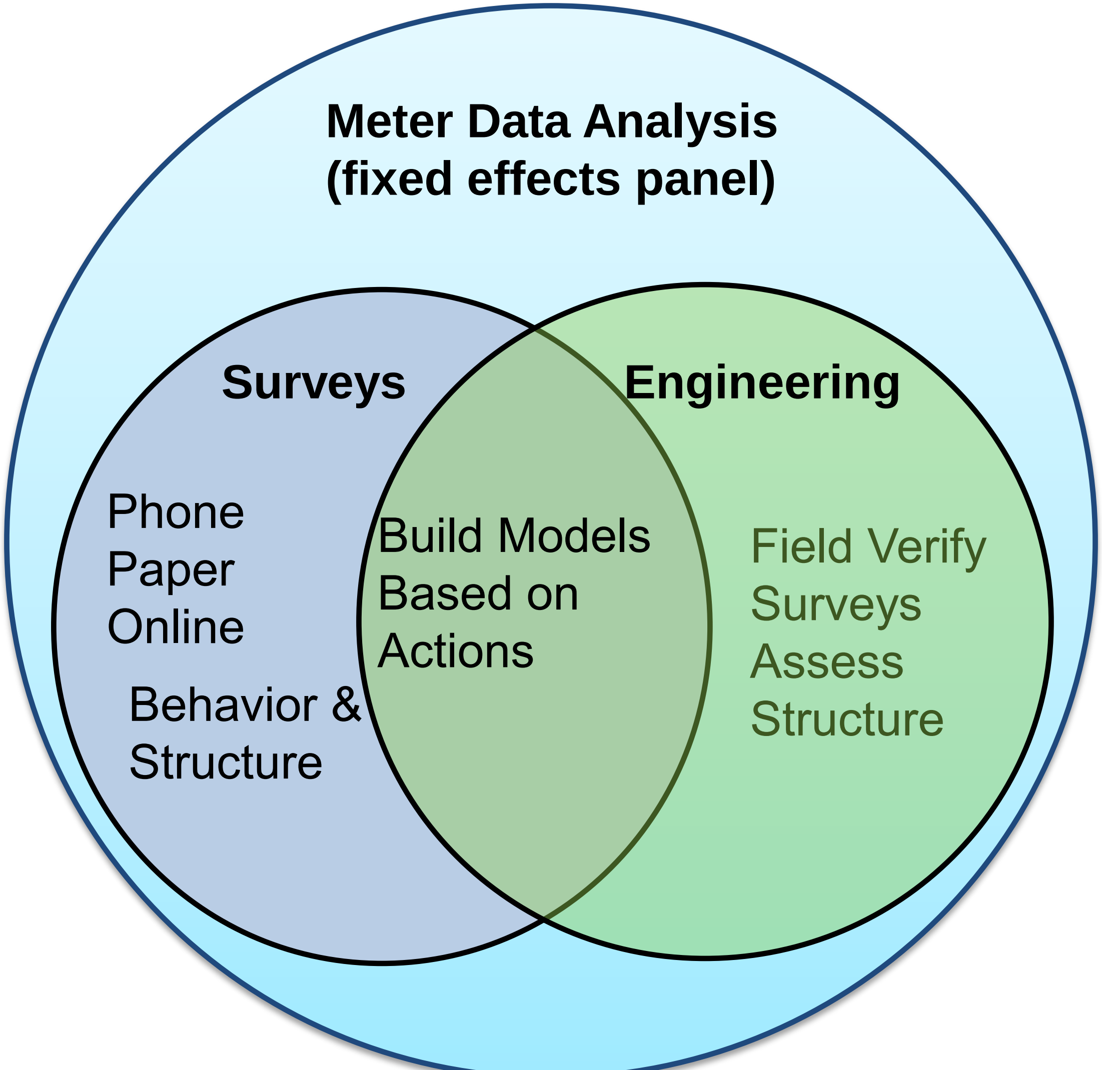
Treatment Group	Objective	Number
Wave 1: 4/08-9/12		
Legacy group (Pilot)	Track savings over 3 ½ years	33,968
Persistence group (selected from legacy group)	Measure savings that persist when reports stopped	9,965

Treatment groups and sizes

Treatment Group	Objective	Number
Wave 1: 4/08-9/12		
Legacy group (Pilot)	Track savings over 3 ½ years	33,968
Persistence group (selected from legacy group)	Measure savings that persist when reports stopped	9,965
Wave 2: 10/10-9/11		
UCLA selection	Identify and target high savers	3,359
SMUD segmentation	Identify and target high savers	3,250
High users	Identify and target high savers	3,292
Electronic report recipients	Test efficacy of sending content electronically	5,930
Seasonal burst recipients	Test efficacy and peak savings from sending reports only in summer	4,976

SMUD™

Study methodology

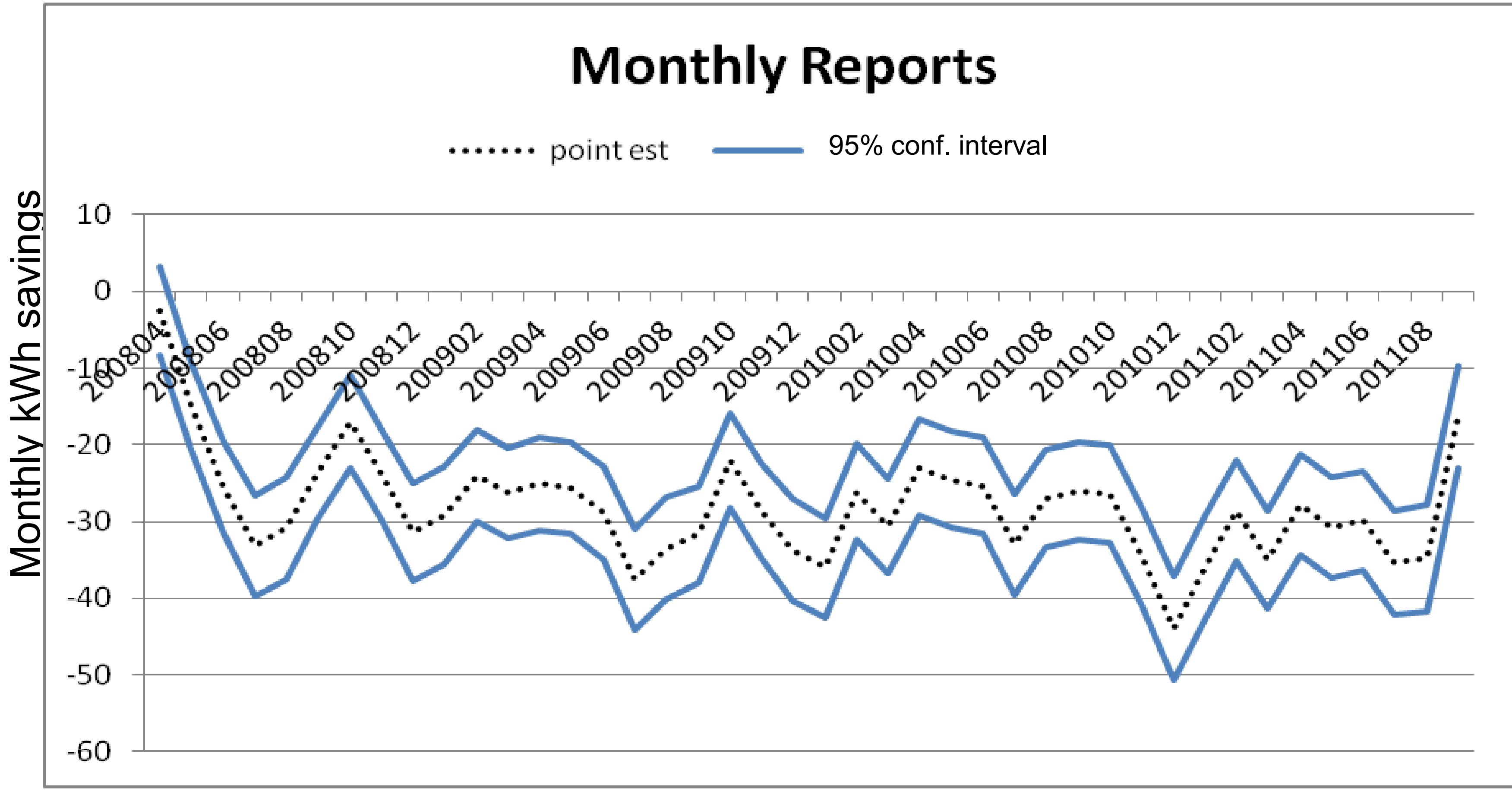


Summary Results for Wave 1

Report Waves & Subgroups	% Usage Change	Annual Usage Change kWh	Monthly Average Use (kWh)	Treatment group size
Wave 1 (pilot)	-2.2%	-249	947	33,968
Wave 1 2008	-1.8%	-207		
Wave 1 2009	-2.4%	-275		
Wave 1 2010	-2.4%	-270		
Wave 1 2011*	-2.1%	-237		
Persistence **	-1.6%	-179	948	9,965

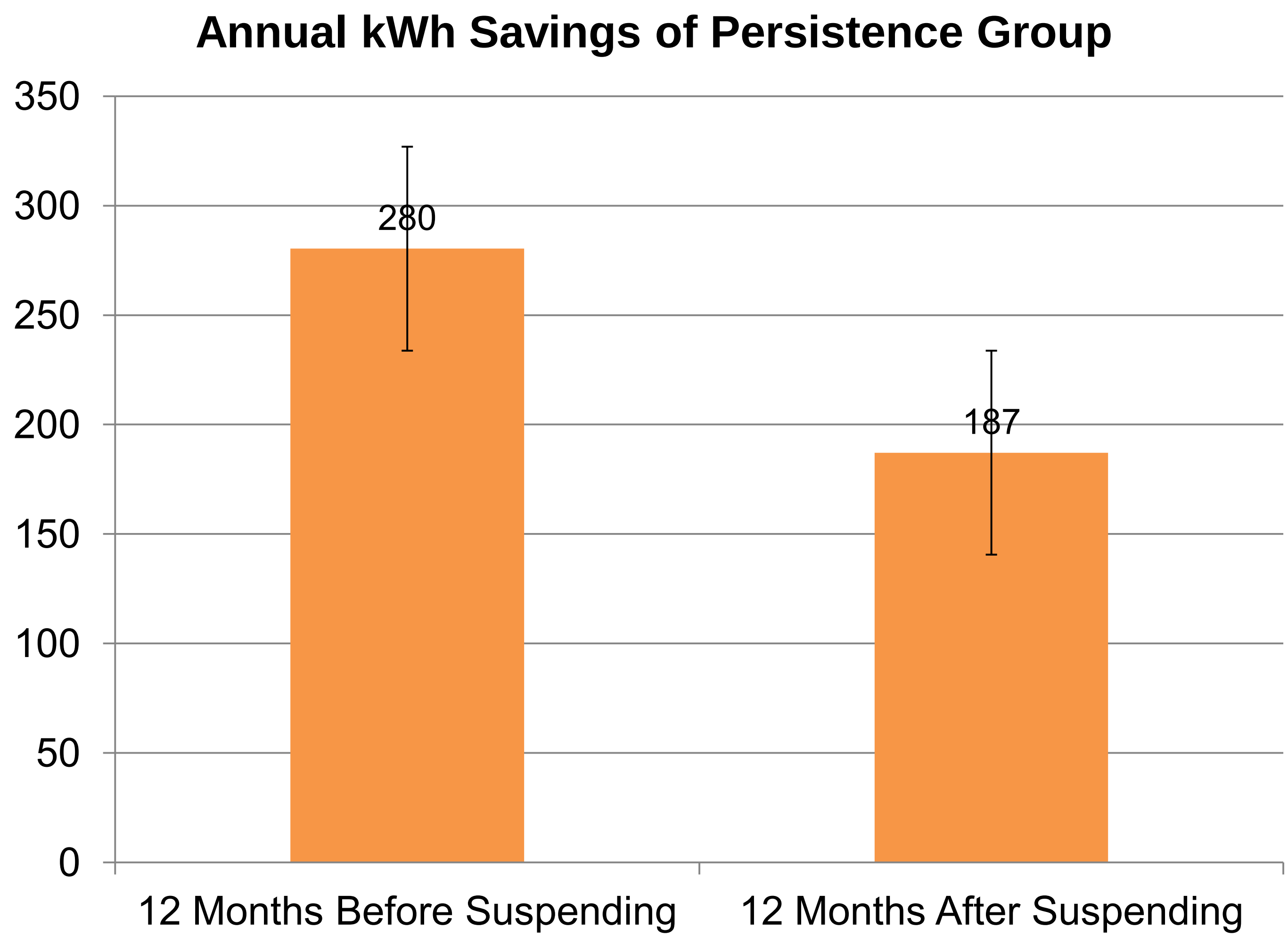
* Partial Year Projection
**Persistence group stopped receiving reports after July 2010

Saving by month (Cont'd)

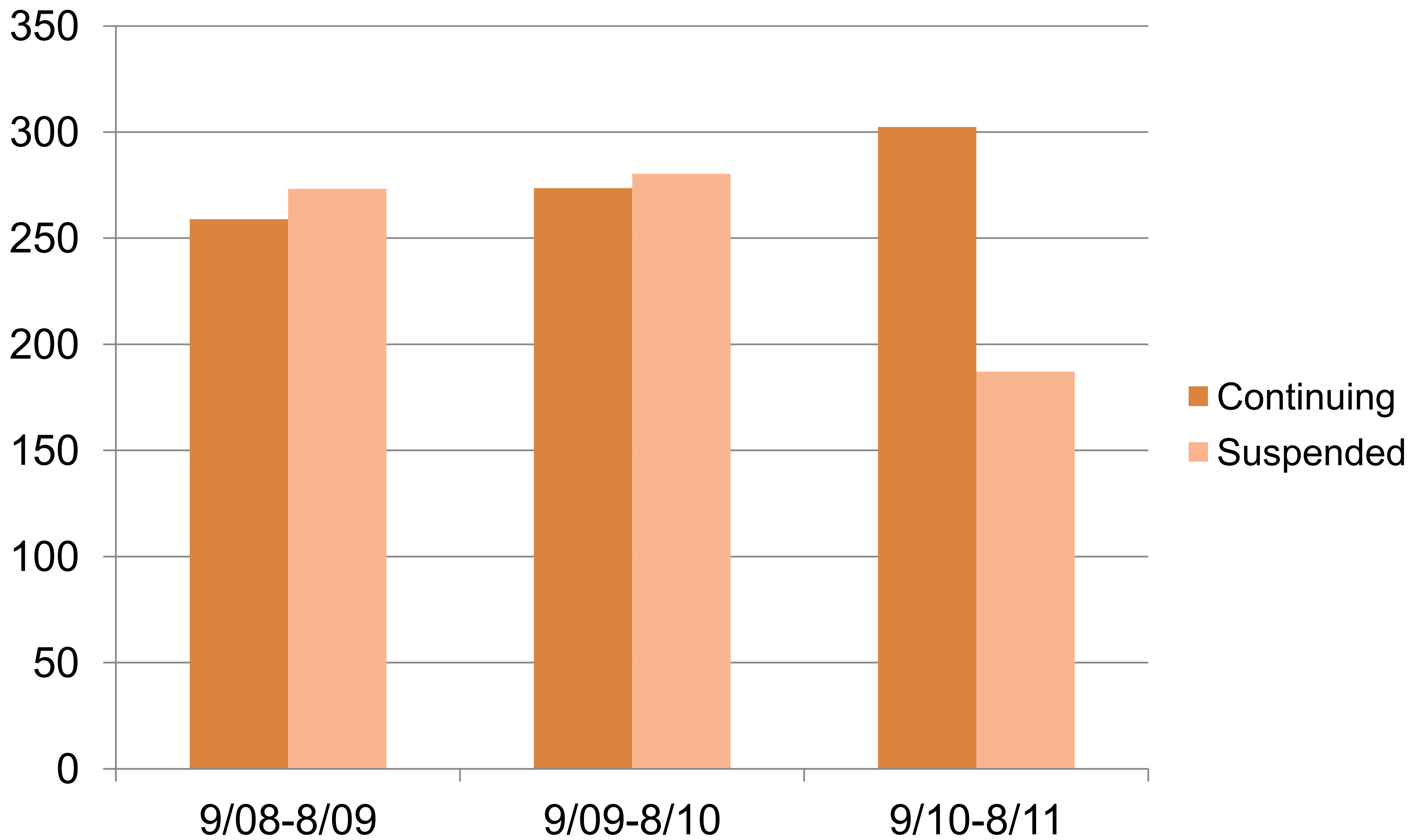


Note the clear seasonality observed in the savings.

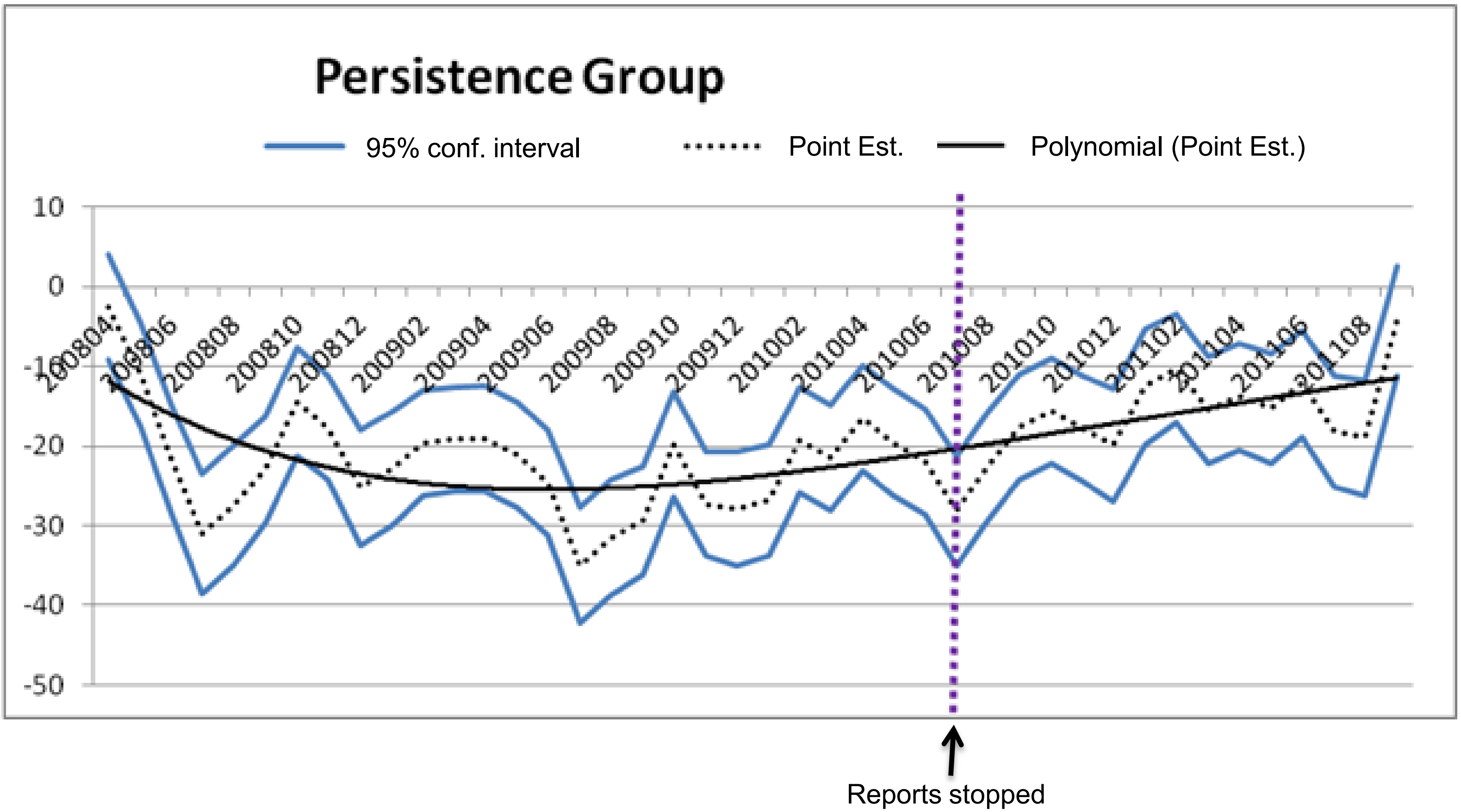
Change in savings after reports suspended



Change in annual savings after reports were suspended

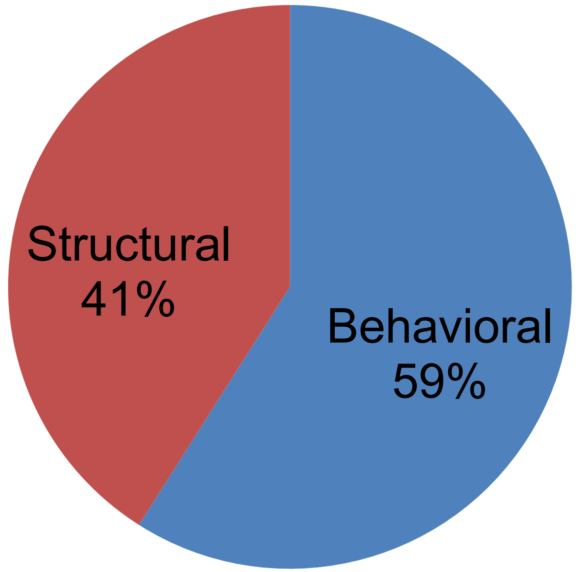


Monthly savings trend for Persistence Group



Where the savings came from

Percent Savings



Most common Structural changes:

- **Replace fridge (5.4% of total kWh savings)**
- Recycle fridge (3.7%)
- Replace AC (3.6%)
- Whole house fan (3.3%)
- Install CFLs (2.2%)

Most common behavioral changes:

- **Set back thermostat (13.0%)**
- **Reduce pool pump hours (7.3%)**
- Hang dry laundry (4.1%)
- Set PC power saving mode (4.1%)
- Close blinds (3.7%)

Conclusions

- Savings hold up over at least four years of continuous engagement with reports
- Two-thirds of savings continues for at least a year after reports are stopped
- 40% of savings is from structural changes that is likely to endure beyond one year
- This fall SMUD will begin rolling 2-year deployments to optimize cost-effectiveness and engage more customers

For more info or a copy of report:

Bruce Ceniceros, SMUD (916) 732-6747

Bruce.Ceniceros@smud.org

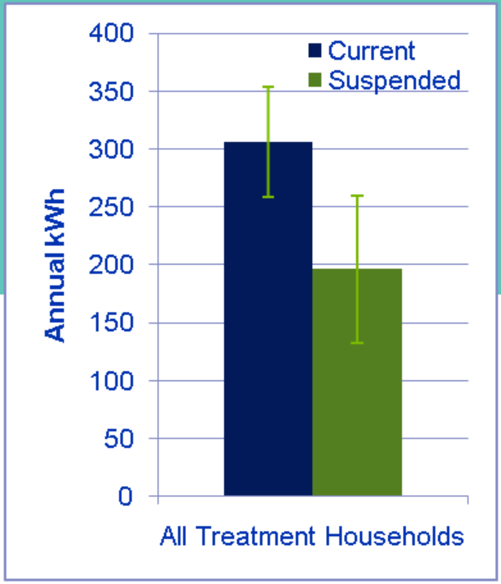
May Wu, Integral Analytics (513) 828-7555

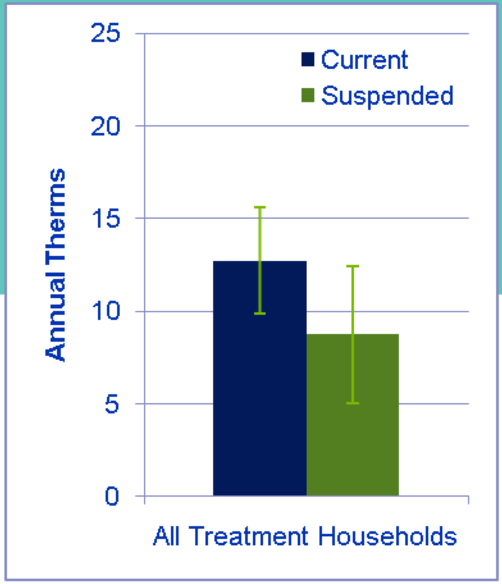
may.wu@integralanalytics.com

Download the report at:

http://integralanalytics.com/ia/smud.aspx

PSE HER Program Persistence





Joel Smith
Program Manager, Customer Solutions

May 30th, 2013

PUGET SOUND ENERGY
The Energy To Do Great Things

PSE Home Energy Reports Recap

- Started with 40,000 test participants in 2008
  - One to One control group
  - Experimental Design
- Removed 10,000 in 2011 to measure persistence
- Savings methodology validated by LBNL
- Started claiming savings in 2011
  - Annual Ex Post evaluation
- Current continuing test group is less than 17,750

Experimental Design

- Dual Fuel (home uses both natural gas and electricity, which are both provided to the service address by Puget Sound Energy)
- Single family residential home
- Uses more than 80 MBtu of energy per year
- Home does not utilize a Solar PV system
- Address must be available with parcel data from the county assessor
- Has a bill history that starts on or before January 1, 2007
- Home must have 100 similar sized homes (neighbors) within a two mile radius
- Home must have automatic daily meter reads

Billing Data Disposition

Population	Control	Treatment	Total
Original population	44,124	39,757	83,881
Not in customer/billing data	35	42	
Not randomly assigned		4,864	
PSE sample population	44,089	34,854	78,943
Other Opower program	111		
Inconsistent zip codes	72	70	
Other data issues	599	507	
Move-outs	9,765	7,816	
Final Sample for 2012	33,693	26,590	60,283
Monthly - Current		12,703	
Monthly - Suspended		6,348	
Quarterly - Current		5,046	
Quarterly - Suspended		2,493	

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

Summary of Annual Savings

Treatment Groups	HER Measured Savings (Per Household)	Joint Savings (Per Household)	Credited Savings	
			Per Household	All Households
Electric (kWh)				
Current	306.0 (+/- 47.9)	5.7	300.3	5,330,705
Suspended	196.0 (+/- 63.3)	11.8	184.2	1,628,920
Total				6,959,625
Gas (therms)				
Current	12.7 (+/- 2.9)	1.4	11.4	201,670
Suspended	8.7 (+/- 3.7)	0.7	8.0	70,573
Total				272,243

Continued vs Suspended Reports

- 10,000 households randomly removed in 2011
  - 8,841 currently remaining
- Savings for both report groups are significantly different than zero, using a 95 percent one-tail test.

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

Program Results

2011

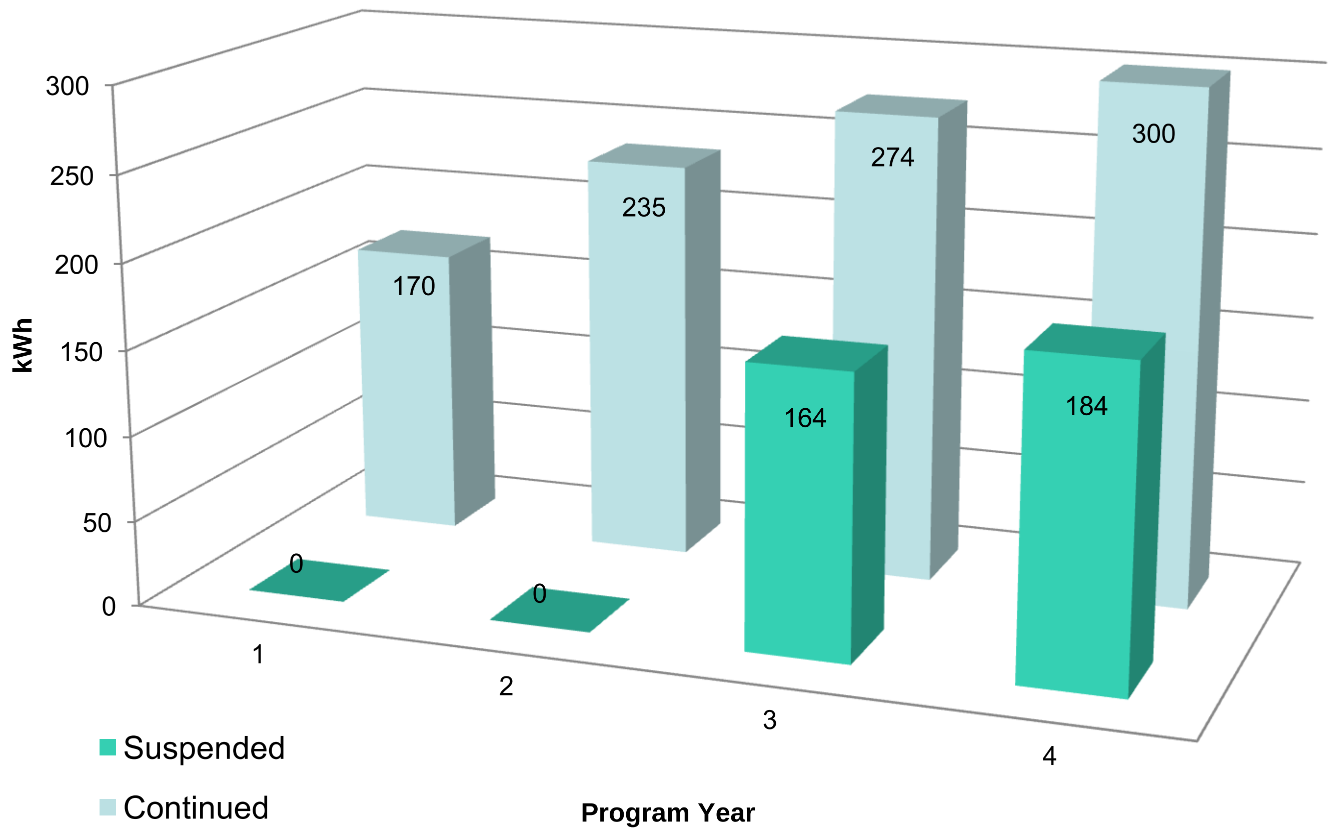
HER Treatment Group	Electric			Gas		
	Consumption	kWh	Percent	Consumption	Therms	Percent
Continued Reports	10,596	276.4	2.6%	920	11.6	1.3%
Suspended Reports		164.3	1.6%		10.9	1.2%

2012

HER Treatment Group	Electric			Gas		
	Consumption	kWh	Percent	Consumption	Therms	Percent
Current Reports	10,591.18	300.34	2.8%	890.24	11.36	1.3%
Suspended Reports		184.25	1.7%		7.98	0.9%

PUGET SOUND ENERGY
The Energy To Do Great Things

Average Savings per Participant



Persistence

- Persistence is clearly demonstrated in the PSE program
  - Results may vary
- Still too early to conclude the next steps on how to incorporate into program design
  - 2012 year results only confuse the issue further
  - We don’t know how long the persistence
  - Multi-year measure life is a game changer

Get it Right From the Start

… or get lucky

- Incorporating Evaluation into Program Design is fundamentally key to verifying success
  - Experimental design
    - Randomly assigned treatment and control groups
  - Size of participant group (treatment and control)
    - Variance of 1.5% to 3.0%
  - Set it and forget it
    - Ensure that there is no interference with treatment and control groups
- There is still much to learn…

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

Summary

- Experimental Design
- Proven Energy Savings
  - 300 kWh per household – continued reports
  - 184 kWh per household – persistence
- Evaluation is Ongoing

Contact

For more information, contact:

Joel Smith
Puget Sound Energy
joel.smith@pse.com
(425) 456-2437

PUGET SOUND ENERGY
The Energy To Do Great Things

Joint Savings Analysis

- Behavioral changes.
- Energy efficient installations and activities performed outside of PSE energy efficiency programs
- Energy efficient installations and activities rebated through PSE energy efficiency programs

Questions for the Presenters

Discussion Part 1:
SMUD and PSE Persistence Research

- What are some lessons learned as far as how this persistence research was designed and executed?
  - What worked well that's worth repeating?
  - What might you do differently next time?
- What are some of the key takeaways from these results?
  - What caveats are necessary in interpreting these results?
  - How might the unique characteristics of each program (and/or its target audience) have played a role?

Discussion Part 2 (Small Groups):

Current and Future Research

Current Persistence Research

- What other persistence research is currently underway <u>on home energy report programs</u>?
- What other persistence research is currently underway or planned for <u>other behavior program types</u>?

Future Persistence Research

- What research gaps remain?
- What program types might benefit from persistence research in the future? How might this be studied?

Small Group Discussion: 15-20 minutes
Large Group Discussion:15-20 minutes

CEE Behavior Committee

Resources and Upcoming Work

Current Behavior Resources

	A	B	X	Y	Z	AA	AB
1	Organization	Program Name	Sector - Publi	Sector - Other	Claiming Saving	Program Duratio	Program Budget
2	AEP Ohio	Home Energy Report			Yes	2 years	$3,000,000
3	Alliance to Save Energy	Green Schools	Public		Yes	2 Years	Varies based on funders
4	Alliance to Save Energy	Green Campus	Public		Yes		Varies based on funders
5	Alliance to Save Energy	SEAT	Public		Yes	1 Day	Varies based on
6	Alliance to Save Energy	Energy Hog	Public		No	1 Day	Varies based on
7	Alliant Energy	PowerHouse TV			No	still active	$500,000
	Ameren Illinois	Home Energy Reports			Yes	3 years	$1,500,000

Welcome | Overview | Behavior Programs

Behavior Insights & Tools

Applying Lessons from the Social Sciences to Efficiency Programs

CEE Working Together, Advancing Efficiency

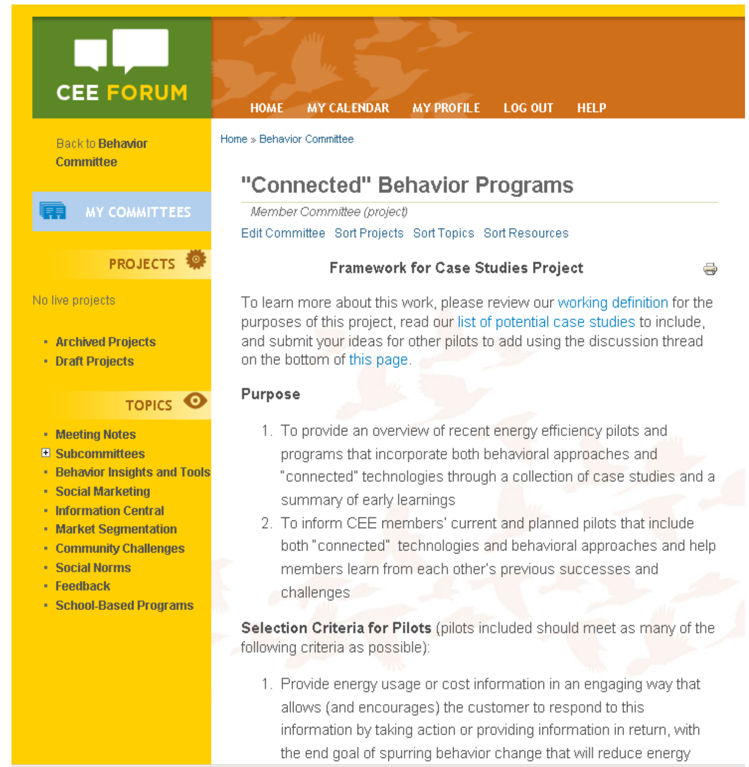
For more information, contact:
Kira Ashby
Program Manager
Behavior Committee
kashby@cee1.org
(617) 337-9281
Consortium for Energy Efficiency
98 North Washington Street, Suite 101
Boston, MA 02114

Written in collaboration with:
Monica Nevius, CEE
Marsha Walton, NYSERDA
Bruce Ceniceros, SMUD
Annika Todd, PEEC

April 2010

Behavior Committee: Work Underway

- “Connected” Behavior Case Studies
- Behavior Program Summary
  - Case Studies
- Regulatory Treatment
- Information Central



For more details on these projects:
www.ceeforum.org

Upcoming Remote Meetings

Meeting Date	Topic
Thursday, June 13th at 11:30am Eastern (8:30am Pacific) *Remote Meeting*	Behavioral Case Studies, next steps for Behavior Program Summary

Contact

Kira Ashby
Program Manager, Behavior
Consortium for Energy Efficiency
(617) 337-9281
kashby@cee1.org

Attachment 226.6

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY AND MINES AND MINISTER RESPONSIBLE FOR HOUSING

Clean Energy Act

Ministerial Order No. M 163

I, Rich Coleman, Minister of Energy and Mines and Minister Responsible for Housing, order that the attached Improvement Financing Regulation is made.

DEPOSITED

July 26, 2012

B.C. REG. 236/2012

JUL 2 4 2012

Date

Minister of Energy and Mines and
Minister Responsible for Housing

(This part is for administrative purposes only and is not part of the Order)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 37 (g.1)

Other:

July 18, 2012

R/512/2012/27

IMPROVEMENT FINANCING REGULATION

Definitions

1 In this regulation:

"**Act**" means the *Clean Energy Act*;

"**application date**" means the date on which an eligible person applies for improvement financing under section 17.1 of the Act;

"**ASTT**" means the Applied Science Technologists and Technicians of British Columbia;

"**billing period**", in relation to an eligible person, means the 12-month period immediately before the application date;

"**HRAI**" means the Heating, Refrigeration and Air Conditioning Institute of Canada;

"**prescribed public utilities**" means the public utilities prescribed under section 3;

"**specified building**" means a residential building of three stories or fewer that occupies no more than 600 m^2 of ground surface, is habitable all year and is

(a) a detached home,

(b) a building that is part of a complex of side-by-side attached buildings, or

(c) a mobile home on a permanent foundation;

"**TECA**" means the Thermal Environmental Comfort Association.

Eligible persons

2 The requirements prescribed for the purposes of the definition of "eligible person" in section 17.1 (1) of the Act are that

(a) the person owns a specified building, or part of a specified building, in

(i) the City of Colwood, or

(ii) in the Regional District of Okanagan-Similkameen, other than those persons who receive electricity from the municipal public utilities of the City of Penticton or the District of Summerland,

(b) in the case of a specified building, or part of a specified building, in the City of Colwood, the building or part of the building is heated with electricity,

(c) the person must have paid on or before the due date all of the bills issued, if any, during the billing period by the public utility from whom the financing is sought, and

(d) the person, on the application date, must have a credit rating of at least 650 on the Equifax Beacon rating system.

Prescribed public utilities

3 (1) The authority is prescribed for the purposes of section 17.1 of the Act respecting eligible persons referred to in section 2 (a) (i) of this regulation.

(2) FortisBC Inc. is prescribed for the purposes of section 17.1 of the Act respecting eligible persons referred to in section 2 (a) (ii) of this regulation.

Terms and conditions

4 (1) The prescribed public utilities, under a financing agreement,

(a) may charge interest on the amount owing under the financing agreement from time to time, but the interest must be payable at a fixed rate that does not exceed 4.5 annual percentage rate, and

(b) must provide that the principal and any interest owing under the financing agreement is payable over a term of not less than 5 years, and that the amount of the principal and interest payments is determined on the basis of an amortization period of not less than 5 years.

(2) For certainty, application fees, administration fees and late payment charges payable by a borrower in connection with the financing under a financing agreement do not constitute interest charges for the purposes of subsection (1).

Prescribed improvements

5 The following improvements are prescribed for the purposes of section 17.1 (4) (d) (i) (B) of the Act:

(a) air sealing;

(b) mechanical ventilation;

(c) attic insulation;

(d) exterior wall insulation;

(e) basement, crawlspace and header insulation;

(f) primary method of heating occupied space;

(g) domestic hot water heating;

(h) window and door replacement.

Aggregate outstanding balances

6 The following amounts for the period from November 1, 2012 to November 1, 2014, are prescribed for the purposes of section 17.1 (8) of the Act:

(a) $500 000, for the authority;

(b) $1 000 000, for FortisBC Inc.

Qualified energy advisors

7 To be a qualified energy advisor for the purposes of section 17.1 of the Act, an energy advisor must

(a) be certified as an energy advisor by Natural Resources Canada, and

(b) be employed by or under contract with a service organization licensed by Natural Resources Canada to perform EnerGuide Rating System evaluations.

Energy reports

8 (1) An energy report respecting a specified building, or part of a specified building, must

(a) be signed and dated by the qualified energy advisor who made the report,

(b) be dated no earlier than 18 months before the date the financing agreement is entered into respecting the specified building or part of the specified building,

(c) include the EnerGuide Rating for Housing rating for the specified building,

(d) include the Residential Retrofit Energy Savings Estimate published by the ministry, and

(e) in the case of a specified building, or part of a specified building, in the City of Colwood, confirm that the building or part of the building is heated with electricity.

(2) The estimate referred to in subsection (1) (d) may be included in an energy report after the report is otherwise completed, provided that the estimate is included in the report before the financing agreement is entered into between the parties.

Qualified person

9 A person is a qualified person for the purposes of section 17.1 of the Act if the person

(a) is the owner of the specified building, or part of the specified building, with respect to which improvements are made under a financing agreement, or

(b) is authorized by the owner referred to in paragraph (a) to carry out the improvements under a financing agreement, and

(i) has attended, or is employed by a person who employs an individual who has attended, an information session respecting section 17.1 of the Act held by the ministry of the minister, and

(ii) for improvements recommended by energy reports signed and dated on or after October 2, 2013, and referred to in column 2 of the following table, has, or is employed by a person who employs an individual who has, one of the credentials referred to in column 1 of the following table opposite that improvement:

Item	Column 1 Credential	Column 2 Improvement
1	(a) Quality First Forced Air Guidelines Certification from TECA (b) SkillTech Residential Heat Loss/Gain and Air System Design Certification from HRAI (c) Registered Applied Science Mechanical Engineering Technologist certificate from ASTT	Air source heat pump installation or a natural gas furnace installation

2	(a) Quality First Hydronics and Combo Certification from TECA (b) SkillTech Residential Heat Loss/ Gain and Air System Design Certification from HRAI (c) Registered Applied Science Mechanical Engineering Technologist certificate from ASTT	Boiler installation
3	(a) Quality First Ventilation Certification from TECA (b) SkillTech Residential Heat Loss/ Gain and Air System Design Certification from HRAI (c) Registered Applied Science Mechanical Engineering Technologist certificate from ASTT	Heat recovery ventilator installation

Notice

10 The form set out in the schedule is prescribed for the purposes of section 17.1 (4) (b) (ii) of the Act.

SCHEDULE

IMPROVEMENT FINANCING: NOTICE OF TRANSFER

This notice is provided by ....*[name of transferor]*.......... to ....*[name of public utility]*.......... (the parties) in accordance with section 17.1 (4) (b) (ii) of the *Clean Energy Act*.

On ....*[date]*........, ...*[name of transferor]*.......... transferred his or her obligations under the financing agreement between the parties that

(a) was entered into on ....*[date]*........ for a term ending on ....*[date]*.......... ;

(b) provided ....*[total amount of financing provided]*.......... at an interest rate of .... , and

(c) financed the following improvements at ....*[address of building]*........ :

..........*[description of each improvement financed by the financing agreement]*..........

....

....

The transferor's customer utility number is.............................. .

The obligations under the financing agreement have been transferred to ....*[name, address and contact information of transferee]*.......... . The outstanding balance under the financing agreement on the date of transfer is ....

The transferee, by signing this notice, acknowledges having received from the transferor a copy of the energy report that supported the financing agreement between the parties, having read and understood the terms and conditions of the financing agreement, and having agreed to assume the outstanding obligations of the transferor under the financing agreement.

....
[signature of transferee] [date]

....
[signature of transferor] [date]

Sep. 13. 2012 9:49AM Rich Coleman, MLA No. 0461 P. 2/2
Sep. 13. 2012 9:12AM No. 0154 P. 3

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY, MINES AND NATURAL GAS AND MINISTER RESPONSIBLE FOR HOUSING AND DEPUTY PREMIER

Clean Energy Act

Ministerial Order No. M 191

I, Rich Coleman, Minister of Energy, Mines and Natural Gas and Minister Responsible for Housing and Deputy Premier, order that the Improvement Financing Regulation, B.C. Reg. 236/2012, is amended

(a) *in section 3 (2) by striking out* "is" *and substituting* "and FortisBC Energy Inc. are", *and*

(b) *by repealing section 6 (b) and substituting the following:*

(b) $500 000, for FortisBC Inc.;

(c) $800 000, for FortisBC Energy Inc.

DEPOSITED

September 13, 2012

B.C. REG. 270/2012

Sept 13/2012

Date

Minister of Energy, Mines and Natural Gas and Minister Responsible for Housing and Deputy Premier

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 37 (g.1)

Other:

September 10, 2012 RESUB 1 R/826/2012/18

Attachment 226.6.1

Energy Efficient Financing: Focus Groups Results

Social Data Research

Specializing in Social Research

Submitted by: SDR Survey Ltd.

Submitted on: November 2, 2010

Submitted to: Edward van Dam, BCH

TOP LINE RESULTS

- Participants expressed interest in seeing the proposed Energy Efficient Financing Program (EEFP) move forward to the next step in development in spite of having many questions about the program.

- Energy conservation was not the main motivator for making home renovations. Main reasons included breakdown of equipment or major repairs needed (i.e., furnace breaks down, roof leaked), wanted to add value and comfort to their home (i.e., kitchen or bathroom updates, drafty windows or walls), and the introduction of government rebate programs (i.e., Power Smart rebates for purchasing new energy efficient appliances; Homeworks) or selling a home.

- Most participants do not have a plan for major renovations in the future – work is completed on an "as need be basis".

- Most prefer to self finance rather than taking out a loan – they don't like going into more debt – particularly with the present economy.

- On face value participants prefer to use their established line of credit, however, offering lower interest rates than the bank was compelling.

- While participants would welcome additional financing sources, there is a perception that the only reason for utilities to be involved is to make more money – not for energy conservation reasons.

- Participants don't understand that they will save money by spending money – instead they see the EEFP loan as a lump sum or capital outlay and not a return on immediate investment.

- Under no circumstance would participants agree to assume the debt of a previous owner when purchasing the house. The debt has to be with the person and not the meter.

Top Line Results (continued)

- To be convinced that they would actually save money participants want confirmation on their utility bill or evidence from their utility company that this was indeed the case.

- At first, there were mixed opinions about the usefulness of having an independent energy assessment conducted in their home, however, after some discussion most participants saw the energy advisor's role as key to adding credibility to the program. Most participants would pay no more than $150 for the energy assessment.

- The partnership between Terasen Gas and BC Hydro was viewed positively; however, participants did not really grasp why the utilities would be involved in the program except to make a profit.

- In general, there was a negative reaction to the idea of having the municipality involved in administering the program for several reasons; first and foremost participants were opposed to having their loan payments added to their high property taxes. Participants were also not confident that "government" could do a good job operating the financial aspects of the program, leaving the tax payers exposed to risk. BC Hydro was not viewed as government by many.

- Participants placed the most trust in BC Hydro as taking the lead in the program, in spite of the fact that a large number were not aware that BC Hydro was a crown corporation.

- Frequent triggers for a loan of some kind were sudden end of life and/or impending house sale.

- A no interest loan option was treated suspiciously, as someone has to pay for it in the end. It was seen as a gimmick which you pay for eventually one way or another.

Purpose of Research

1. Introduce the Energy Efficient Financing Program Concept.
2. Gauge first reactions to the program concept
3. Understand how people make decisions about major home renovations – does energy conservation play a role?
4. Identify how participants finance major home renovations and discuss issues related to financing.
5. Test participants' comfort level and understanding of the funders (BC Hydro, Terasen Gas, Municipality) and their roles in developing and delivering the program.
6. Determine participants' level of interest in the program going forward to next steps.

Methodology

- Six focus groups were held: two in Coquitlam on October 26th; two in Kamloops on October 27th ; and two in Prince George on October 28th, 2010.
- There were 49 participants in total.
- Profile of participants in each group:
  - General population
  - Home owners with older homes
  - Mixed household status - mainly couples & families with children
  - Mixed gender
  - Mixed ages; ages ranged from 18-65
  - Mixed ethnicity
  - Mixed occupations including retired

Focus Group Limitation

- The results cannot be projected to the total target population of BC as the number of participants is too small to be statistically significant.
- Focus Groups help researchers acquire insights and explore a range of responses to ideas on various issues.

Current Household Description

As part of the warm-up exercise, participants were asked how long they had lived at their current address, how old their home was, how they heated their home including their hot water tank, and how much they paid for their utilities each month.

- Most participants lived in homes that were between 20 and 50 years old and were not the first owners.

- For those who heated their home and water with gas, monthly bills ranged from $100 to $200 per month on average; monthly electrical bills were less - $50-$100/month (unless house is heated with electricity); some participants did not know the cost; some included water in this estimate.

- Many participants saw their monthly utility bills as high and expressed concern about rising costs.

Ways Participants Have Reduced Energy Consumption

Participants were asked in what ways they had tried to reduce the energy consumption in their home.

- Many participants reported having made major purchases, renovations and repairs in the past few years including replacing the furnace, windows & doors, roof, adding insulation, buying new kitchen appliances & updating bathrooms.
- Some participants mentioned strategies such as turning the thermostat down or off in the rooms they were not occupying, replacing their conventional light bulbs with new energy saving bulbs, using more natural light, adding low flow faucets, turning their fireplace pilot lights off when not in use, not using their gas fireplace at all, using power bars to consolidate electronics and shutting them off when not in use, & buying insulated curtains.
- Saving money was not necessarily a reason for making changes – comfort & safety (drafts from windows, turning gas fireplace pilot lights off for safety of young children) were among reasons mentioned.

"I consider hydro manageable right now, not reasonable, but if the rates go up…"

"It's not just the money, it's our lifestyle now. We don't use most of the rooms in the house so why heat them."

Motivations for Making Home Renovations in the Past

Participants were asked what motivated them to make the major changes they listed.

It became clear from the reasons given that "going green" or becoming more energy efficient was not the main motivator.

- There seemed to be three main triggers: (1) "end of term" or a complete breakdown (furnace stops/too noisy, roof old & leaky, appliances stop functioning, etc.); (2) Opportunity arises such as recent government rebate and tax refund programs; and, (3) buying or selling a house (buyers add renovations to mortgage, sellers want to add value to home to increase resale price). Participants noted major cost savings after replacing older equipment. <u>Only a small minority of participants have a plan or ongoing budget to undertake preventative repairs and replacements.</u> Many participants are "do it yourselfers" or have friends or relatives that help with renovations.

"The old furnace was dying so we had the energy audit done which confirmed we needed a new furnace. The old one sounded like a rocket whenever it started up. Our bills went down by 1/3 the following year"

"My nephew is in construction and he told me what to do to sell our house. Our real estate agent agreed."

"We live in an old house and the roof needed to be repaired. It's duplex so that was an issue because the owner at the time didn't want to share the cost. We tried to fix just our part but that didn't work. There's a new owner now who did agree to share the cost so now I think the house is more energy efficient and looks good too."

Possible Future Renovations

Participants where asked if they had any plans to renovate or what might motivate them to undertake major renovations in the future.

- Most participants had no immediate plans and were not setting aside money to undertake major renovations (although some did).
- Updating bathrooms & kitchens would be desirable for some participants.
- One participant wanted to convert the wood furnace in the house to a gas furnace.
- A few participants were undertaking small renovations with help from family and friends.
- Saving money motivates a few participants to consider renovating.
- Complete breakdown of older furnace would be a motivator.

"Our furnace is 20 years old but works great. I'm keeping it up because I had to buy a new car this year and we don't want to over extend ourselves. If it died completely we'd have to replace it"

Reasons for Not Renovating

The reasons given for not making major energy saving changes to their home at this point seemed to fall into four categories:

(1) The cost of the renovation cannot be justified by the savings.

"You have to justify the cost. It's just not there yet but if energy rates go up we will do it."

"You have to lay out a large amount of money for things like a heat pump and I'm just not sure I'll get it back in savings."

(2) Has to be a need not just a want.

"The way I look at it, I wouldn't spend $25,000 to renovate a bathroom just to sell a house but if it needs to be done then yes."

(3) Don't have the money and don't want to borrow the money.

" I'm in debt over my eyeballs so if it's not broken I don't fix it."

"I get a rash when I borrow money."

(4) Onerous regulations.

"In our municipality if you do anything you have to have an inspector come in and you end up having make all sorts of other changes you weren't planning to bring things up to code. I hate having the City tell me what to do."

Financing Major Renovations

Participants were asked how they financed their renovations/how they would finance future renovations.

- Most participants self financed the work through sources such as personal savings, major credit cards, store credit card promotions (Sears, Home Depot etc.), personal line of credit or a combination.
- In a few instances, where the cost to renovate was higher it was added to the mortgage or line of credit.
- Many participants had access to in kind help through family, friends and co-workers especially in the interior.
- Many participants had an aversion to borrowing money at this point in time and would defer the work until they had enough savings.
- A few participants mentioned that they were somewhat influenced to use their credit card because it gave them air miles.

First Reaction (unaided) to the Energy Efficient Financing Program

When the moderator first introduced the concept of the Energy Efficient Financing Program, participants had many questions. Questions were fairly consistent across all groups and included the following:

- What's the advantage over my bank's mortgage or line of credit financing? Is the rate better?
- What are the terms? Amortization period? Can I pay the loan off whenever I want? Is there a payoff penalty?
- How would you qualify? What if our house is already mortgaged for more than 90% of its value?
- Is this is a private or government run program? Government programs run out of money or time to qualify.
- Is there a minimum or maximum I would have to borrow? "I just want a loan to do windows or insulation-I don't want a lot of money".
- Are there administration fees and if so what are they? Are they hidden in the small print?
- With the low interest rate, how would I know if I am actually saving money as shown on my utility bill?

More Questions about the EEFP

- Would someone have to come into your home to do an assessment? Who pays for the assessment?
- What types of renovations qualify? Does it include appliances?
- What happens with respect to the building code in an old house?
- Where would you get the qualified people who would do the work?
- Does it have to be a professional or can we do the work ourselves? Can we get several estimates?
- What happens if I sell my house before the loan is repaid?
- What happens if the cost goes over the estimate or the work is below par? Who is responsible?
- Will the funds be available when I need them? (referring to breakdowns where work has to be started immediately)
- How easy is the application process?
- Who gets paid directly?

Further Questions Related to Financing Arrangements

Following the initial discussion about the concept, the moderator provided more information about how the financing would work and possible sources – BC Hydro, Terasen Gas, or the municipality. This information generated additional questions and raised some concerns.

- Participants seemed perplexed and suspicious at first as to the motives of the utilities and municipality to be involved *(“Why are they doing this?” “What’s the catch?”)* and could not see the link between energy conservation programs and the utility companies.
- There was a negative reaction in some groups to having their municipality involved. *(“I think it’s odd that the municipality is part of this.” I wouldn’t like to have the municipality add this to my bill. It’s already high enough. I would rather have smaller monthly bills.” “Where would they get the money?”) “It’s run by politicians and that’s not good.”*
- However, in other groups, the municipal involvement was seen as a plus. *(“I trust my municipality more than I trust the utility companies.”) (“I would rather give money back to my town than to other companies. At least the money stays here.”)*
- Many raised the concern of what happens when you sell your house – can the loan be paid off? *(“If I was buying a house and it had a loan attached to it, it would put me off.” “But it could also be a selling feature – it could be negotiable during the sale contract.”)*
- Some asked if there would be penalties if the loan was paid off earlier and what other terms and conditions might be placed on the loan. *(“It better be easier than at the bank or it wouldn’t be worth it.”)*
- A few participants asked if people with poor credit ratings or no credit history could obtain the loan. (“These are the people who really need help.”)
- Some had concern about how the money would be distributed. *(“Do you have to spend the money first and then submit your bills and wait for reimbursement?” , “How long?”)*

Preferences Related to Which Entity Should Deliver the Program

There was some discussion about which of the three sources – BC Hydro, Terasen Gas, and the municipality – would be in the best position to deliver the program.

- Many participants preferred BC Hydro over Terasen Gas or their municipality to run the program, although for some participants either utility was fine; their municipality was least preferred in most groups.

- Although BC Hydro is held in high regard many participants were not aware that BC Hydro is a Canadian Crown Corporation.

"BC Hydro is still a Canadian Company is it not?"

- Some participants were cautious in their endorsement of BC Hydro or Terasen being the lead while others were more enthusiastic.

"Financing is not really their line of work – they should stick to just providing incentives for energy conservation."

"I would think they are doing this because they know something about the area. BC Hydro is facing a major capital cost and they want people to reduce their consumption."

"It makes total sense for them to do this because they are already well set up for monthly for monthly billing."

"This could be like one stop shopping for some people because they don't want to take the time to go through the bank process."

"The pooling and accessibility of the funds might be appealing particularly if you can't go anywhere else."

First Reaction to Home Energy Assessments

There were a number of viewpoints given when participants were introduced to the home energy assessment component of the program.

- In general, participants viewed the assessment as a valuable component of the program. *("The option should be there to use an auditor." "I would want to know what my biggest bang for the buck would be." "I think that's an excellent idea.")*
- A few participants expressed concerns about the energy assessment. *("We had an energy audit before we replaced our furnace and it was so general, it was almost useless." "If I need a new furnace, I don't see why I would need an assessment." "Is the advisor neutral?" "I would go for that if the advisor is independent." "Do I need one if I have contractor friends with the same knowledge?")*
- Most participants were willing to pay for the assessment.
- The amount participants viewed as reasonable ranged from $50 to $150.
- The option to include the assessment fee in the loan was viewed positively.

Potential Role of the Home Energy Advisor

Participants had a number of suggestions when it came to the role that the energy advisor should play: They including providing:

- Information that would help applicants select a contractor
- Guidance about the expected costs of completing different types of needed renovations
- An approved list of contractors available to do the work
- Information on the potential energy savings after the improvements are made
- Will the energy advisor be the energy installation inspector?
- Can the advisor recommend contractors?

Who Owns the Process?

Several questions arose pertaining to the process:

- What if things go wrong in the installation?
- What happens if the contractor asks for more money or it's installed incorrectly?
- Who signs off after the installation?
- Who receives the money?

How to Communicate Information About the Program

Participants were asked for their input on how best to communicate information about the program to the public. A number of suggestions were given including:

- Sending flyers with utility bills but make sure flyers are a different colour
- Advertise on radio & TV
- Create a catchy slogan/buzz words that capture the concepts of saving money, adding value to home, easy process, one stop shopping, etc.
- Provide brochures at stores frequented by contractors like Home Depot, Rona, Home Hardware, etc.
- Engage a trustworthy spokesperson/champion for the program
- Set up booths at home shows, provide assistance with paper work

Financial Options

- When given the option to receive a rebate with self financing versus full loan with low interest financing, participants were split.
- A certificate documenting energy saving reno work was nice to have but not necessary.
- ‘No interest loans’ were very appealing but again what are the conditions? No interest was “too good to be true!” What is the catch? We have to pay the piper in the end” “Will we pay more for our utilities?”

Should the Program Move Forward?

Participants were interested enough in the concept to suggest that the program <u>should move forward</u> in a pilot form. Uptake will depend on addressing the following issues:

- That the program is delivered by a credible agency – BC Hydro is preferred *("I have more confidence in a public program otherwise it could be a scam.")* However, a few participants had concerns about implications to taxpayers if a crown or government agency was involved. *("It would be important that the loan is tied to your house in some way in case the program is stopped.")*
- That the interest rate is competitive and preferably lower than the bank *("If car companies can offer no interest loans why can't this program?")*
- That the terms are flexible. *("My preference would be to have low monthly payments at a fixed rate for 5 years"; I would say for <$20,000 5-10 year terms but for a big renovation let's say $100,000+ you'd want a 25 year* amortization *period.")*
- Providing small monthly payments *(I couldn't afford $400/month but under $100 would be OK.")*
- Have the option of paying back the loan at any time.
- Include appliances and other environmentally friendly products such as 'green' interior paint
- Allow estimates from several contractors of applicant's choice and provide list of reputable companies *("I don't like the way the insurance companies force you to go to certain companies for the work.")*
- Streamline the application process – there is a perception that government programs involve lots of red tape and paperwork to complete.
- Have clear guidelines regarding the status of the loan when owners decide to sell their home – participants were opposed to passing the debt on to the next owner and saw this as detriment to selling the home rather than an asset.
- Make sure energy assessments are conducted by independent advisors with no ties to outside contractors
- Develop criteria for selection of contractors (Who qualifies to do the work?)
- Determine who is responsible for incomplete work, sub-par work or cost overruns.

Challenges

- Participants cannot see that the savings on their new energy efficient renovations will be equal to or greater than the monthly interest and capital installments on their bills. It is strictly a cost with some unknown energy savings. They translate that to mean that the new windows and insulation eliminates the drafts or that the furnace "now works". Similarly, how much money do you save when you install a CFL light bulb? They know the capital cost but do not know the savings. It's an unknown. Can the utilities define or prove the savings?

- Participants misunderstand the ulterior motivations of BC Hydro and Terasen Gas for promoting the program.

  "They just want to make money. Consumers save energy and BC Hydro resells this "saved" energy to make more money."

- Few participants acknowledged scarce energy resources (and rising rates) as a possible motive for utilities to be involved in program.

More challenges

- Few consumers want more debt on their present debt load. Even low interest (never defined in the groups) is still unwanted additional debt.
- Low interest was expected to be lower than bank interest and lower than line of credit.
- Selling a house is good reason to fix it up before and complete EE renovations; however most participants were not selling their homes and lived in them for 20 plus years.
- Sudden end of life is an important trigger for a loan but the work has to be completed immediately especially for replacement of heating and hot water systems. Line of credit solves that problem.
- Appliances were expected to be part of the EE financing.
- Many wanted the program to cover Do It Yourself renovators.

Final Research Caution

- Although the EE Financing program, as a concept, was positively received, few critical details were defined. One should treat this as an exploratory stage.
- Further research should be conducted after the program has been developed to the next stage

Attachment 230.1.2

Education and behaviour programs funding request

FORTIS BC™

Contact information

Organization	Contact person	Phone

Mailing address	E-mail address

General information

Program name	Start date	End date

Resources requested

Funding amount requested ($)	Is street team/ambassador presence required? (yes or no)

Brochures (indicate quantities below)

______ Commercial Rebates ______ Residential Rebates

______ General conservation (______ English ______ Punjabi ______ Mandarin)

FortisBC branded prizing (refer to energy specialist guide), list type and quantity below.

Other (please specify)

Program overview – please ensure project is gas focused

Target audience (Whole company? Specific department? Include number of departments and number of staff in department)

Background, purpose of running campaign

Goals

Marketing/communication plan outline (include dates)

How will FortisBC be recognized? (E-blasts, posters, verbal recognition)

Graphs, charts or images

Budget

Provide background on total project costs and **detailed** breakdown of how funding will be distributed

Other funders/partners

Measurement and evaluation

Please summarize how you will measure and evaluate the impact of the program

When will the final report will be delivered to FortisBC Eg: Pre and post surveys

For FortisBC internal use only			
Date received	Approved budget	Signed off by	Signature

Attachment 231.2

103.2 Does FEU believe it is best practice to evaluate results of a pilot on a certain technology or measure before starting a program on that technology or measure?

Response:

The FEU believe that this varies from measure to measure and program to program. There are some measures and programs where it is not necessary to run a pilot first, because that measure or a similar program may have been undertaken in other jurisdictions and data or best practices from those other jurisdictions can be used as the basis for activity by FEU. Where there is a lack of industry data for measures and programs, the Companies will take a more cautious approach and run a small limited pilot prior to launching a full program. Please see also the response to BCUC IR 2.103.1.

114.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.197.3

EEC Funding for Innovative Technologies

"FEU believes that the funding envelope for Innovative Technologies…should be $1.5 million for 2012 and $1.5 million for 2013 which funding will be used to undertake pilots, demonstration projects, facilitate studies, reports and EM&V. Of the $1.5 million each year, $1 million will be allocated to undertake pilots and demonstration projects and to support market-ready technology programs, $300,000 will be allocated for EM&V to confirm savings claims and guide the development of future programs that will be offered within the residential, commercial, and industrial sector, and the remaining $200,000 will be focused on reports and studies."

114.1 Please list other sources of data FEU could use for EM&V to confirm savings claims and for reports and studies to estimate energy savings and market availability.

Response:

Through a combination of informal discussions with consultants and/or other industry experts, reviewing credible studies and the Utilities' own analysis, the energy savings are estimated during program planning stages. The FEU may also consider adopting the estimated savings from other similar programs offered through different utilities and jurisdictions. Going forward, as additional data becomes available through ongoing measurement and verification processes, the FEU will refine the assumptions and update the savings in future annual reports. Please also see the response to BCUC IR 1.212 series for additional information.

[redacted]

Attachment 234.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 234.2

Attachment 234.2

Residential Programs

Quadra Homes - Total incentive: $154,171

2012 – Yearly incentive $135,188

Quadra Homes - New Construction Pilot Program - 1st Installment — **Incentive amount: $130, 688**

This EnerGuide 80 Rowhome Pilot was initiated in 2010 in order for the FEU to gain experience on the EnerGuide 80 building process, energy labeling requirements, and to obtain cost benefit inputs for efficient natural gas appliances in new homes. A total of 151 units were completed over several years. Units are EnerGuide 80+ and include Tankless water heaters, Electronic ignition fireplaces and High Efficiency furnaces.

Quadra Homes - New Construction Pilot Program - 2nd Installment — **Incentive amount: $4, 500**

Second installment of Quadra Homes - New Construction Pilot - paid through the New Home Program (invoiced by BC Hydro at the time).

2013 – Yearly incentive $18,983

Quadra Homes - New Construction Pilot Program - 3rd Installment — **Incentive amount: $18, 983**

Third installment of Quadra Homes - New Construction Pilot.

Industrial Programs

Quesnel River Pulp Mill (QRP) - Total incentive: $350,000

2012 – Yearly incentive $250,000

Technology Retrofit Program — **Incentive amount: $250,000**

This amount was paid to Quesnel River Pulp Mill (QRP) after validating the commissioning of an approved energy efficiency project. The amount is a quarter of the total funding approved for this project.

By implementing the approved energy efficiency project, QRP is estimated to save 70,000 gigajoules per year.

2013 – Yearly incentive $100,000

Technology Retrofit Program — **Incentive amount: $100,000**

Estimated second installment to be paid to QRP that will be calculated from the savings achieved by the energy efficiency project in the first year after its commissioning.

Canfor Pulp Limited Partnerships (CPLP) - Total incentive: $225,000

2013 – Yearly incentive $225,000

Technology Retrofit Program — **Incentive amount: $112,500**

This amount was paid to Canfor Pulp Limited Partnerships (CPLP) after validating the commissioning of an approved energy efficiency project. The amount is a quarter of the total funding approved for this project.

By implementing the approved energy efficiency project, CPLP is estimated to save 38,000 gigajoules per year.

Technology Retrofit Program — **Incentive amount: $112,500**

Estimated second installment to be paid to CPLP that will be calculated from the savings achieved by the energy efficiency project in the first six months after its commissioning.

Commercial Programs

BC Housing - Total incentive: $141, 490	
2012 – Yearly incentive $60,850	
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
Light Commercial Boiler Program Provided one incentive for a boiler installation.	**Incentive amount: $850**
2013 – Yearly incentive $80,640	
Efficient Boiler Program Will provide one incentive for a boiler installation.	**Incentive amount: $4,440**
Energy Assessment Program Provided eleven energy assessments.	**Incentive amount: $16,200**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

Bird Construction - Total incentive: $118,800	
2013 – Yearly incentive $118,800	
Efficient Boiler Program Will provide one incentive for boiler installations.	**Incentive amount: $118,800**

City of Burnaby - Total incentive: $138,400	
2012 – Yearly incentive $73,500	
Energy Assessment Program Provided nine energy assessments.	**Incentive amount: $13,500**
Efficient Boiler Program Provided one incentive for a boiler installation.	**Incentive amount: $60,000**
2013 – Yearly incentive $64,900	
Efficient Boiler Program Three boiler incentives are projected.	**Incentive amount: $57,600**
EnerTracker Ten applications were submitted.	**Incentive amount: $7,300**

District of North Vancouver - Total incentive: $182,415	
2012 – Yearly incentive $71,495	
Energy Assessment Program Provided five energy assessments.	**Incentive amount: $8,100**
Efficient Boiler Program Provided one incentive for a boiler installation.	**Incentive amount: $2,400**
Efficient Commercial Water Heater Program Provided one incentive for a water heater installation.	**Incentive amount: $995**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $110,920	
Efficient Boiler Program Provided one incentive for a boiler installation.	**Incentive amount: $48,000**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

EnerTracker Four applications were submitted.	**Incentive amount: $2,920**

Fraser Health Authority - Total incentive: $115,185	
2012 – Yearly incentive $14,850	
Energy Assessment Program Provided eight energy assessments.	**Incentive amount: $14,850**
2013 – Yearly incentive $100,335	
Continuous Optimization Program Eleven applications were submitted.	**Incentive amount: $95,955**
EnerTracker Six applications were submitted.	**Incentive amount: $4,380**

Interior Health Authority - Total incentive: $220,593	
2012 – Yearly incentive $156,836	
Continuous Optimization Program Provided six incentives.	**Incentive amount: $14,486**
Energy Assessment Program Provided forty two energy assessments.	**Incentive amount: $82,350**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $63,757	
Continuous Optimization Program Three applications were submitted.	**Incentive amount: $2,762**
Efficient Commercial Water Heater Program Provided one incentive for a water heater installation.	**Incentive amount: $995**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

Ivanhoe Cambridge II Inc. - Total incentive: $177,466	
2013 – Yearly incentive $177,466	
Continuous Optimization Program Two applications were submitted.	**Incentive amount: $8,466**
Efficient Boiler Program Provided three incentives for boiler installations.	**Incentive amount: $169,000**

Northern Health Authority - Total incentive: $251,050	
2012 – Yearly incentive $95,333	
Commercial Custom Design Program - Retrofit Projects Incented 50% of two energy studies.	**Incentive amount: $33,640**
Continuous Optimization Program One application was submitted.	**Incentive amount: $1,693**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $155,717	
Continuous Optimization Program Three applications were submitted.	**Incentive amount: $7,758**
Commercial Custom Design Program - Retrofit Projects A capital incentive and implementation bonus is projected.	**Incentive amount: $73,459**

Efficiency a la Carte Provided one incentive for a food equipment installation.	**Incentive amount: $2,500**
Efficient Boiler Program Provide one incentive for a boiler installation.	**Incentive amount: $12,000**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

Pacific National Exhibition - Total incentive: $180,000	
2013 – Yearly incentive $180,000	
Efficient Boiler Program Provided one incentive for boiler installations.	**Incentive amount: $180,000**

Provincial Health Authority - Total incentive: $113,127	
2012 – Yearly incentive $60,000	
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $53,127	
Continuous Optimization Program Three applications were submitted.	**Incentive amount: $7,397**
Energy Specialist Program Will fund the Energy Specialist position for 2013. Part year funding due to hiring a new specialist.	**Incentive amount: $45,000**
EnerTracker One application was submitted.	**Incentive amount: $730**

School District 36 (Surrey) - Total incentive: $312,552	
2012 – Yearly incentive $202,443	
Continuous Optimization Program Provided fourteen incentives.	**Incentive amount: $72,455**
Efficient Boiler Program Provided seven incentives for boiler installations.	**Incentive amount: $129,988**
2013 – Yearly incentive $110,109	
Continuous Optimization Program Thirteen applications were submitted	**Incentive amount: $14,369**
Efficient Boiler Program Provided one incentive for a boiler installation.	**Incentive amount: $24,940**
Energy Assessment Program Submitted eight applications.	**Incentive amount: $10,800**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

School District 37 (Delta) - Total incentive: $123,000	
2012 – Yearly incentive $63,000	
Efficient Commercial Water Heater Program Provided one incentive for a water heater installation.	**Incentive amount: $3,000**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $60,000	
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

School District 38 (Richmond) - Total incentive: $268,990	
2012 – Yearly incentive $181,065	
Continuous Optimization Program Provided six incentives.	**Incentive amount: $36,745**
Efficient Boiler Program Provided six incentives for boiler installations.	**Incentive amount: $84,320**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $87,925	
Continuous Optimization Program Submitted five applications.	**Incentive amount: $22,525**
Energy Assessment Program Submitted four applications.	**Incentive amount: $5,400**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

School District 41 (Burnaby) - Total incentive: $272,556	
2012 – Yearly incentive $89,728	
Efficient Boiler Program Provided two incentives for boiler installations.	**Incentive amount: $29,728**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $182,828	
Efficient Boiler Program Provided five incentives for boiler installations with one projected.	**Incentive amount: $122,828**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

School District 63 (Saanich) - Total incentive: $145,409	
2012 – Yearly incentive $22,829	
Continuous Optimization Program Provided three incentives.	**Incentive amount: $22,829**
2013 – Yearly incentive $122,580	
Continuous Optimization Program Provided two incentives.	**Incentive amount: $6,872**
Efficient Boiler Program Provided two incentives for boiler installations with one pending application.	**Incentive amount: $60,708**
Energy Specialist Program Will fund the Energy Specialist position for 2013. Part year funding due to hiring a new specialist.	**Incentive amount: $55,000**

Simon Fraser University - Total incentive: $153,939	
2012 – Yearly incentive $91,451	
Continuous Optimization Program Provided five incentives.	**Incentive amount: $28,001**
Efficient Commercial Water Heater Program Provided one incentive for water heater installation.	**Incentive amount: $750**
Energy Assessment Program Provided two energy assessments.	**Incentive amount: $2,700**

Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $62,488	
Continuous Optimization Program Four applications were submitted.	**Incentive amount: $2,488**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

UBC/UBC Properties Trust - Total incentive: $311,504	
2012 – Yearly incentive $173,572	
Commercial Custom Design Program – New Construction Projects Incented 50% of an energy study.	**Incentive amount: $13,450**
Continuous Optimization Program Provided thirty three incentives.	**Incentive amount: $96,072**
Energy Assessment Program Provided three energy assessments.	**Incentive amount: $4,050**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $137,932	
Continuous Optimization Program Provided twenty two incentives.	**Incentive amount: $25,236**
Energy Assessment Program Provided one energy assessment.	**Incentive amount: $2,700**
Efficient Boiler Program Provided two incentives for boiler installations.	**Incentive amount: $46,006**
Efficient Commercial Water Heater Program Provided one incentive for a water heater installation.	**Incentive amount: $3,990**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

Vancouver Coastal Health Authority - Total incentive: $161,810	
2012 – Yearly incentive $86,532	
Continuous Optimization Program Provided four incentives.	**Incentive amount: $21,132**
Energy Assessment Program Provided two energy assessments.	**Incentive amount: $5,400**
Energy Specialist Program Provided funding for one Energy Specialist.	**Incentive amount: $60,000**
2013 – Yearly incentive $75,278	
Continuous Optimization Program Submitted fifteen applications.	**Incentive amount: $13,278**
Efficiency a la Carte Provided two incentives for installing foodservice equipment.	**Incentive amount: $2,000**
Energy Specialist Program Will fund the Energy Specialist position for 2013.	**Incentive amount: $60,000**

Vancouver Island Health Authority - Total incentive: $618,759	
2012 – Yearly incentive $405,136	
Continuous Optimization Program Provided fourteen incentives.	**Incentive amount: $113,833**
Commercial Custom Design Program - Retrofit Projects Incented 50% of an energy study.	**Incentive amount: $10,597**
Efficiency a la Carte Provided an incentive for installing foodservice equipment.	**Incentive amount: $2,000**
Energy Assessment Program Provided eight energy assessments.	**Incentive amount: $12,150**
Efficient Boiler Program Provided three incentives for boiler installations.	**Incentive amount: $80,556**
Efficient Commercial Water Heater Program Provided one incentive for water heater installation.	**Incentive amount: $6,000**
Energy Specialist Program Provided funding for three Energy Specialist positions.	**Incentive amount: $180,000**
2013 – Yearly incentive $213,623	
Continuous Optimization Program Five applications were submitted.	**Incentive amount: $21,347**
Energy Assessment Program Provided one energy assessment.	**Incentive amount: $2,700**
Efficient Boiler Program Submitted one application for a boiler installation.	**Incentive amount: $9,576**
Energy Specialist Program Will fund three Energy Specialist positions for 2013.	**Incentive amount: $180,000**

Attachment 234.4

Residential Program Area

Program	Service Territory	2012		2014		2018	
		Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending
Residential	FEI	9,921	47.9%	9,378	31.5%	10,197	32.6%
	FEVI	1,020	33.8%	1,089	27.1%	1,094	27.0%
	FEW	7	15.2%	94	39.8%	93	41.4%
	Total	10,948	46.1%	10,557	31.0%	11,382	32.0%
Commercial	FEI	3,904	18.9%	9,286	31.2%	8,240	26.3%
	FEVI	925	30.6%	1,720	42.8%	1,702	42.0%
	FEW	39	84.8%	118	49.9%	107	47.7%
	Total	4,865	20.5%	11,124	32.7%	10,049	28.3%
Industrial	FEI	347	1.7%	1,738	5.8%	2,709	8.7%
	FEVI	10	0.3%	174	4.3%	274	6.8%
	FEW	0	0.0%	0	0.0%	0	0.0%
	Total	358	1.5%	1,912	5.6%	2,983	8.4%
Low Income	FEI	525	2.5%	2,039	6.8%	2,855	9.1%
	FEVI	78	2.6%	287	7.1%	323	8.0%
	FEW	0	0.0%	0	0.0%	0	0.0%
	Total	603	2.5%	2,324	6.8%	3,178	8.9%
Innovative Technologies	FEI	353	1.7%	1,106	3.7%	1,183	3.8%
	FEVI	40	1.3%	101	2.5%	26	0.6%
	FEW	0	0.0%	0	0.0%	0	0.0%
	Total	394	1.7%	1,207	3.5%	1,210	3.4%
Conversation, Education & Outreach	FEI	1,909	9.2%	2,137	7.2%	2,137	6.8%
	FEVI	291	9.6%	240	6.0%	240	5.9%
	FEW	0	0.0%	24	10.3%	24	10.9%
	Total	2,200	9.3%	2,400	7.1%	2,400	6.7%
Enabling Activities	FEI	274	1.3%	4,109	13.8%	3,972	12.7%
	FEVI	75	2.5%	406	10.1%	393	9.7%
	FEW	0	0.0%	0	0.0%	0	0.0%
	Total	349	1.5%	4,515	13.3%	4,365	12.3%
Portfolio Level Activities	FEI	3,464	16.7%	0	0.0%	0	0.0%
	FEVI	581	19.2%	0	0.0%	0	0.0%
	FEW	0	0.0%	0	0.0%	0	0.0%
	Total	4,045	17.0%	0	0.0%	0	0.0%
Total Portfolio	**FEI**	**20,697**	**100.0%**	**29,792**	**100.0%**	**31,293**	**100.0%**
	FEVI	**3,020**	**100.0%**	**4,018**	**100.0%**	**4,052**	**100.0%**
	FEW	**46**	**100.0%**	**236**	**100.0%**	**224**	**100.0%**
	Total	**23,762**	**100.0%**	**34,039**	**100.0%**	**35,567**	**100.0%**

Notes:
Discrepancies may exist due to rounding
In 2012 Enabling Activities were included under the Residential Program Area

Residential Program Area

Program	Free Ridership %		Spillover %		Non-energy benefits % 2012 [1]		Measures 2012		Lifespan of Asset (years)		Service Territory	2012		2014		2018	
	2012	2014-2018	2012	2014-2018	2012	2014-2018	2012	2014-2018	2012	2014-2018		Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending
ENERGY STAR® Water Heater Program	10%	10%	n/a	0%	15%	15%	ESTAR 0.67 EF Storage Tank	ESTAR 0.67 EF Storage Tank - discontinued 2017 due to regulation	FEI - 13 FEVI - 10	13	FEI	97	0.5%	987	3.3%	1,235	3.9%
							Non-Condensing Tankless	Non-Condensing Tankless - may be discontinued 2016 to promote higher efficiency condensing technology	20	20							
							Condensing Tankless	Condensing Tankless	20	20	FEVI	35	1.2%	99	2.5%	124	3.1%
							Hybrids	Hybrids	20	20	FEW	1	2.2%	11	4.7%	14	6.2%
							Condensing Storage Tank	Condensing Storage Tank	FEI - 13 FEVI - 10	13	Total	133	0.6%	1,096	3.2%	1,372	3.9%
EnerChoice Fireplace Program	24%	Retrofit - 26% New Construction - 13%	n/a	0%	n/a		EnerChoice Fireplace(Retrofit)	EnerChoice Fireplace(Retrofit)	15	15	FEI	914	4.4%	1,142	3.8%	668	2.1%
							EnerChoice Fireplace(New Construction)	EnerChoice Fireplace(New Construction)	15	15							
											FEVI	291	9.6%	271	6.7%	159	3.9%
											FEW	3	6.5%	14	5.9%	8	3.6%
											Total	1,208	5.1%	1,427	4.2%	835	2.3%
Appliance Service Program (“Give your Furnace/Fireplace Some TLC”)	n/a	n/a	n/a	n/a	n/a		Furnace Service	Furnace Service									
							Fireplace Service	Fireplace Service			FEI	602	2.9%	411	1.4%	411	1.3%
											FEVI	105	3.5%	41	1.0%	41	1.0%
											FEW	0	0.0%	5	2.1%	5	2.2%
											Total	707	3.0%	456	1.3%	456	1.3%
Energy Efficient Home Performance Program (LiveSmart BC)	20%	19%	n/a	15%	n/a	n/a	Air Sealing and Draft Proofing	Air Sealing and Draft Proofing	10 to 15	20							
							Attic Insulation	Attic Insulation	20 to 25	20	FEI	4,597	22.2%	1,265	4.2%	1,633	5.2%
							Basement Insulation	Basement Insulation	20 to 25	20	FEVI	344	11.4%	126	3.1%	163	4.0%
							Wall Insulation	Wall Insulation	20 to 25	20	FEW	0	0.0%	14	5.9%	18	8.0%
							Crawl Space and Misc	Champion Bonus	20 to 25	20	Total	4,941	20.8%	1,405	4.1%	1,815	5.1%
							Windows										
							Certified Insulation										
ENERGY STAR® Washers and Other Measures for DHW Conservation	20%	n/a	n/a	0%	n/a	n/a	Select ENERGY STAR Washing Machines	n/a	14	n/a							
											FEI	609	2.9%	n/a	n/a	n/a	n/a
											FEVI	51	1.7%	n/a	n/a	n/a	n/a
											FEW	0	0.0%	n/a	n/a	n/a	n/a
											Total	660	2.8%	n/a	n/a	n/a	n/a
Furnace Replacement Program	8%	8%	n/a	0%	15%	15%	Standard Efficiency Furnace	Standard Efficiency Furnace	18	18							
							Mid-Efficiency Furnace	Mid-Efficiency Furnace	18	18	FEI	2,649	12.8%	3,020	10.1%	2,997	9.6%
							Boilers	Boilers	18	18	FEVI	127	4.2%	302	7.5%	300	7.4%
											FEW	3	6.5%	34	14.4%	33	14.7%
											Total	2,779	11.7%	3,355	9.9%	3,330	9.4%
New Home Program (New Construction - EnerGuide 80 and Energy Efficient Appliances)	10%	12%	n/a	0%	15%	15%	EG80 Single Family Dwellings	SFD - High efficient (ESTAR)	25+	25							
							EG80 Townhome/Rowhome	Townhome/Rowhome High Efficient (ESTAR)	25+	25	FEI	205	1.0%	933	3.1%	706	2.3%
							Boilers	Boilers	18	18	FEVI	8	0.3%	93	2.3%	71	1.8%
											FEW	0	0.0%	10	4.2%	8	3.6%
											Total	213	0.9%	1,036	3.0%	784	2.2%
Financing Pilot	TBD	0%	n/a	0%	n/a	n/a	Primary Space Heating	Primary Space Heating	To be determined	n/a							
							Air Sealing and Insulation	Air Sealing and Insulation	To be determined	n/a	FEI	24	0.1%	112	0.4%	309	1.0%
							Hot Water Heating	Hot Water Heating	To be determined	n/a	FEVI	0	0.0%	0	0.0%	0	0.0%
							Window and Door Replacement	Window and Door Replacement	To be determined	n/a	FEW	0	0.0%	0	0.0%	0	0.0%
											Total	24	0.1%	112	0.3%	309	0.9%
Low-Flow Fixtures	n/a	10%	n/a	0%	n/a	n/a	n/a	Low-Flow Fixtures	n/a	10							
											FEI	n/a	n/a	261	0.9%	261	0.8%
											FEVI	n/a	n/a	26	0.6%	26	0.6%
											FEW	n/a	n/a	3	1.3%	3	1.3%
											Total	n/a	n/a	290	0.9%	290	0.8%
New Technologies Program	n/a	5%	n/a	0%	n/a	15%	n/a	New Technologies	n/a	10							
											FEI	n/a	n/a	236	0.8%	325	1.0%
											FEVI	n/a	n/a	24	0.6%	32	0.8%
											FEW	n/a	n/a	3	1.3%	4	1.8%
											Total	n/a	n/a	262	0.8%	361	1.0%
Customer Engagement Tool for Conservation Behaviours	n/a	0%	n/a	0%	n/a	15%	n/a	Home Energy Reporting	n/a	1							
											FEI	n/a	n/a	520	1.7%	1,161	3.7%
											FEVI	n/a	n/a	58	1.4%	129	3.2%
											FEW	n/a	n/a	0	0.0%	0	0.0%
											Total	n/a	n/a	578	1.7%	1,290	3.6%
Non Program Specific Expenses																	
											FEI	224	1.1%	491	1.6%	491	1.6%
											FEVI	59	2.0%	49	1.2%	49	1.2%
											FEW	0	0.0%	0	0.0%	0	0.0%
											Total	283	1.2%	540	1.6%	540	1.5%
All Programs																	
											FEI	**9,921**	**47.9%**	**9,378**	**31.5%**	**10,197**	**32.6%**
											FEVI	**1,020**	**33.8%**	**1,089**	**27.1%**	**1,094**	**27.0%**
											FEW	**7**	**15.2%**	**94**	**39.8%**	**93**	**41.4%**
											Total	**10,948**	**46.1%**	**10,557**	**31.0%**	**11,382**	**32.0%**

Notes:

1. Non Energy Benefits of 15% is reflected in the MTRC calculation.

Commercial Program Area

Program	Free Ridership % 2012	Free Ridership % 2014-2018	Spillover % 2012	Spillover % 2014-2018	Non-energy benefits % 2012	Non-energy benefits % 2014-2018	Measures 2012	Measures 2014-2018	Lifespan of Asset (years) 2012	Lifespan of Asset (years) 2014-2018	Service Territory	2012 Spending ($000s)	2012 % of Total Service Territory Spending	2014 Spending ($000s)	2014 % of Total Service Territory Spending	2018 Spending ($000s)	2018 % of Total Service Territory Spending	Comments
Light Commercial Boiler Program	18	n/a	n/a	n/a	0%	n/a	Condensing boiler (Less than 300 MBH) Mid-efficiency boiler (Less than 300 MBH)	n/a	20	n/a	FEI FEVI FEW Total	10 1 0 11	0.0% 0.0% 0.0% 0.0%	n/a				Program closed as of May 2012. Eligible boilers rolled up into Efficient Boiler Program in 2012 & 2013 and subsequently rolled into the Space Heat Program from 2014-2018.
Efficient Boiler Program	18	n/a	n/a	n/a	0%	n/a	Condensing boiler (all MBH size classes) Mid-efficiency boiler (all MBH size classes)	n/a	20	n/a	FEI FEVI FEW Total	1,348 442 0 1,790	6.5% 14.6% 0.0% 7.5%	n/a				Measures rolled up into Space Heat Program from 2014-2018.
Space Heat Program	n/a	16%	n/a	TBD	n/a	0%	n/a	Condensing boiler (all MBH size classes) Mid-efficiency boiler (all MBH size classes) Condensing rooftop unit	n/a	19.7	FEI FEVI FEW Total	n/a		1,329 439 18 1,786	4.5% 10.9% 7.6% 5.2%	1,631 538 22 2,191	5.2% 13.3% 9.8% 6.2%	Condensing rooftop units are expected to be introduced to the program in 2016 or 2017. Note that condensing rooftop unit assumptions may changed based on the actual results of the pilot program under the Innovative Technologies Program area.
Efficient Commercial Water Heater Program	5%	5%	n/a	n/a	0%	0%	Condensing storage and volume type water heater Near condensing storage and volume type water heater Condensing on-demand water heater	Condensing storage and volume type water heater Near condensing storage and volume type water heater Condensing on-demand water heater	12	12	FEI FEVI FEW Total	185 18 0 204	0.9% 0.6% 0.0% 0.9%	n/a				Measures rolled up into Water Heating Program from 2014-2018
Water Heating Program	5%	5%	n/a	TBD	0%	0%	Condensing storage and volume type water heater Near condensing storage and volume type water heater Condensing on-demand water heater	Condensing storage and volume type water heater Near condensing storage and volume type water heater Condensing on-demand water heater	12	12	FEI FEVI FEW Total	n/a		204 33 2 239	0.7% 0.8% 0.8% 0.7%	285 46 3 334	0.9% 1.1% 1.3% 0.9%	
Commercial Energy Assessment Program	35%	35%	n/a	TBD	0%	0%	Walkthrough energy assessment and written report	Medium business walkthrough energy assessment and written repor Small business walkthrough energy assessment and written report Small Industrial/Manufacturing walkthrough energy assessment and Restaurant/Foodservice walkthrough energy assessment and writter	1	1	FEI FEVI FEW Total	417 64 15 497	2.0% 2.1% 32.6% 2.1%	409 46 5 460	1.4% 1.1% 2.1% 1.4%	415 47 5 466	1.3% 1.2% 2.2% 1.3%	The energy assessment measures as previously reported in Exhibit B-1-1, FEI 2014-2018 PBR, Appendix I-2 have been updated to reflect current customer segmentation plans.
Customized Equipment Upgrade Program (Commercial Custom Design Program)	Variable	10%	n/a	TBD	0%	0%	Utility funded energy study Utility incented Energy Conservation Measures as identified in the energy study and approved by the utility. Energy Saving Measures are variable.	Utility funded energy study Utility incented Energy Conservation Measures as identified in the energy study and approved by the utility. Energy Saving Measures are variable.	Variable	10.5	FEI FEVI FEW Total	60 15 0 74	0.3% 0.5% 0.0% 0.3%	2,892 494 67 3,453	9.7% 12.3% 28.3% 10.1%	2,557 441 59 3,057	8.2% 10.9% 26.3% 8.6%	Increased 2014-2018 spend a result of shifting a portion of the Continuous Optimization Program budget to the Customized Equipment Upgrade Program (Commercial Custom Design Program).
Continuous Optimization Program	0%	0%	n/a	TBD	15%	15%	Re/Retro commissioning study "Near time" energy consumption monitoring	Building recommissioning EMIS	5	5	FEI FEVI FEW Total	718 159 22 899	3.5% 5.3% 47.8% 3.8%	1,356 153 13 1,522	4.6% 3.8% 5.5% 4.5%	465 52 3 520	1.5% 1.3% 1.3% 1.5%	The Continuous Optimization Program budget as presented in Exhibit B-1-1, FEI 2014-2018 PBR, Appendix I-2 has since been reduced. The long-run marginal cost of electricity negatively impacted BC Hydro's cost-effectiveness test, which in turn caused BC Hydro toclose the program to new participants in 2013. Given that new participants will no longer be accepted into the program beyond 2013, the budget has been reduced accordingly. (Note that the following measure terms are used interchangeably: Re/Retro commissioning study and building recommissioning; "near time" energy consumption monitoring and EMIS.)
Spray Valve Program	12%	n/a	n/a	n/a	n/a	n/a	Low flow pre-rinse spray valves	n/a	5	n/a	FEI FEVI FEW Total	20 4 0 23	0.1% 0.1% 0.0% 0.1%	n/a				Program rolled up into Commercial Food Service Program 2014-2018
Efficiency a la Carte- Commercial Kitchen Program	20%	n/a	n/a	n/a	0%	0%	Deep fryer Griddle Combination oven Convection oven Rack oven Conveyor oven Steam cooker	n/a	12	n/a	FEI FEVI FEW Total	53 25 0 79	0.3% 0.8% 0.0% 0.3%	n/a				Program rolled up into Commercial Food Service Program 2014-2018
Commercial Food Service Program	n/a	16%	n/a	TBD	0%	0%	n/a	Deep fryer Griddle Combination oven Convection oven Rack oven Conveyor oven Steam cooker Dishwasher Spray valve Faucet aerator	n/a	9.1	FEI FEVI FEW Total	n/a		364 41 4 410	1.2% 1.0% 1.7% 1.2%	564 64 6 635	1.8% 1.6% 2.7% 1.8%	
MURB Program	10%	n/a	n/a	TBD	n/a	n/a	Low flow showerheads	n/a	5	n/a	FEI FEVI FEW Total	4 0 0 4	0.0% 0.0% 0.0% 0.0%	n/a				The MURB Program will transition from the Commercial Program area to the Residential Program area.
Fireplace Timers Pilot Program	0%	n/a	n/a	n/a	n/a	n/a	Electronic fireplace "time-of-operation" controller	n/a	5	n/a	FEI FEVI FEW Total	9 1 0 10	0.0% 0.0% 0.0% 0.0%	n/a				The initial results of the impact study are inconclusive. A a result, it is not certain if a full program rollout will ensue.
Radiant Tube Heaters Pilot Program	0%	n/a	n/a	n/a	n/a	n/a	Radiant tube heaters	Radiant tube heaters	20	n/a	FEI FEVI FEW Total	1 0 0 1	0.0% 0.0% 0.0% 0.0%	n/a				This pilot study has been transferred from the Commercial Program area to the Innovative Technologies Program area. Based on the results of the pilot, radiant tube heaters may be added at a later date as an additional measure under the Space Heat Program.
EnerTracker Pilot Program	6%	6%	n/a	TBD	n/a	n/a	Energy management information system	Energy management information system	1	1	FEI FEVI FEW Total	122 0 0 122	0.6% 0.0% 0.0% 0.5%	409 0 0 409	1.4% 0.0% 0.0% 1.2%	0 0 0 0	0.0% 0.0% 0.0% 0.0%	EnerTracker will remain a pilot program for three years The FEU will conduct program evaluation near the end of this timeframe to determine the success of the pilot. If deemed successful, the program will continue thereafter.
Energy Specialist Program	0%	0%	n/a	n/a	n/a	n/a	Energy Specialist position	Energy Specialist position	n/a	n/a	FEI FEVI FEW Total	800 188 0 989	3.9% 6.2% 0.0% 4.2%	1,397 349 0 1,746	4.7% 8.7% 0.0% 5.1%	1,397 349 0 1,746	4.5% 8.6% 0.0% 4.9%	
Mechanical Insulation Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FEI FEVI FEW Total	n/a		n/a				The Mechanical Insulation Pilot study has been suspended, and the companies do not currently have a formal plan to pursue this initiative.
PSECA Program	n/a										FEI FEVI FEW Total	2 0 0 2	n/a					In 2012 the Commercial Energy Efficiency Program Area incurred expenditures of $1,793.87 under the Public Sector Energy Conservation Agreement ("PSECA") Program. These expenditures were related to performing post-completion
Non Program Specific Expenses											FEI FEVI FEW Total	155 4 2 161	0.7% 0.1% 4.3% 0.7%	926 165 9 1,100	3.1% 4.1% 3.8% 3.2%	926 165 9 1,100	3.0% 4.1% 4.0% 3.1%	
All Programs											**FEI** **FEVI** **FEW** **Total**	**3,904** **925** **39** **4,865**	**18.9%** **30.6%** **84.8%** **20.5%**	**9,286** **1,720** **118** **11,124**	**31.2%** **42.8%** **49.9%** **32.7%**	**8,240** **1,702** **107** **10,049**	**26.3%** **42.0%** **47.7%** **28.3%**	

Notes:
The FEU continue to work towards identifying an appropriate spillover rate. The TRC's presented in the PBR used a 0% spillover rate for the time being.

Industrial Program Area

Program	Free Ridership % 2012	Free Ridership % 2014-2018	Spillover % 2012	Spillover % 2014-2018	Non-energy benefits % 2012 2012	Non-energy benefits % 2012 2014-2018	Measures 2012 2012	Measures 2012 2014-2018	Lifespan of Asset (years) 2012	Lifespan of Asset (years) 2014-2018	Service Territory	2012 Spending ($000s)	2012 % of Total Service Territory Spending	2014 Spending ($000s)	2014 % of Total Service Territory Spending	2018 Spending ($000s)	2018 % of Total Service Territory Spending
Technology Retrofit Program	10%(3)	n/a(1)	n/a	n/a(1)	n/a	n/a(1)	Variable. Dependent upon participant's proposed Energy Saving Measures.	n/a(1)	Variable. Dependent upon participant's proposed Energy Saving Measures.	n/a(1)	FEI	269	1.3%	n/a(1)	n/a(1)	n/a(1)	n/a(1)
											FEVI	0	0.0%				
											FEW	0	0.0%				
											Total	269	1.1%				
Energy Audit & Analysis Program	10%	n/a(1)	n/a	n/a(1)	n/a	n/a(1)	Variable. Dependent upon participant's proposed Energy Saving Measures.	n/a(1)	Variable.	n/a(1)	FEI	45	0.2%	n/a(1)	n/a(1)	n/a(1)	n/a(1)
											FEVI	10	0.3%				
											FEW	0	0.0%				
											Total	55	0.2%				
Process Heat Program	To be determined	n/a(2)	n/a	n/a(2)	n/a	n/a(2)	To be determined	n/a(2)	To be determined	n/a(2)	FEI	20	0.1%	n/a(2)	n/a(2)	n/a(2)	n/a(2)
											FEVI	0	0.0%				
											Few	0	0.0%				
											Total	20	0.1%				
Customer Energy Analysis	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FEI	n/a	n/a	n/a	n/a	n/a	n/a
											FEVI						
											FEW						
											Total						
Industrial Optimization Program	n/a	21%	n/a	0%	n/a	n/a	n/a	Industrial Energy Audit	n/a	1							
								Industrial Assessment		1	FEI	n/a	n/a	1,378	4.6%	1,762	0
								Industrial sector Study		1	FEVI			138	3.4%	176	0
								Technology Implementation		10	FEW			15	6.3%	20	0
								Small Industrial Implementation		10	Total			1,531	4.5%	1,958	0
Specialized Industrial Process Technology Program	n/a	18%	n/a	0%	n/a	n/a	n/a	Steam Distribution Program	n/a	6							
								Process Boiler System		20	FEI	n/a	n/a	246	0.8%	574	0
								Wood Drying process		10	FEVI			27	0.7%	63	0
								-		-	FEW			1	0.4%	1	0
								-		-	Total			274	0.8%	638	0
Non Program Specific Expenses											FEI	8	0.0%	238	0.8%	238	0.8%
											FEVI	0	0.0%	24	0.6%	24	0.6%
											FEW	0	0.0%	0	0.0%	0	0.0%
											Total	8	0.0%	262	0.8%	262	0.7%
All Programs											**FEI**	**347**	**1.7%**	**1,738**	**5.8%**	**2,709**	**8.7%**
											FEVI	**10**	**0.3%**	**174**	**4.3%**	**274**	**6.8%**
											FEW	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**
											Total	**358**	**1.5%**	**1,912**	**5.6%**	**2,983**	**8.4%**

(1) The Technology Retrofit Program and Energy Audit & Analysis Program were incorporated to the Industrial Optimization Program.

(2) The Process Heat Program was renamed as “Process Boiler System” and now resides under the Specialized Industrial Process Technology program.

(3) The 10% Free Ridership is attributed to the single participant of the Technology Retrofit program in 2012. However, Free Ridership will vary as eligible industrial projects will have disctinct conditions.

Steam Distribution Program
Process Boiler System
Wood Drying process

Low Income Program Area

Program	Free Ridership %		Spillover %		Non-energy benefits % 2012		Measures 2012		Lifespan of Asset (years)		Service Territory	2012		2014		2018	
	2012	2014-2018	2012	2014-2018	2012	2014-2018	2012	2014-2018	2012	2014-2018		Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending
Residential Energy Efficiency Works (REnEW)	n/a	n/a	n/a	n/a	30%	30%	Training	Training	n/a	n/a	FEI	91	0.4%	41	0.1%	81	0.3%
											FEVI	0	0.0%	41	1.0%	0	0.0%
											FEW	0	0.0%	0	0.0%	0	0.0%
											Total	91	0.4%	81	0.2%	81	0.2%
Energy Savings Kit (ESK)	27%	27%	n/a	n/a	30%	30%	Faucet Aerators, Low Flow Showerheads, Water Heater Pipe Wrap, Caulking, Draft Proofing, Outlet Gaskets, Window Film	Faucet Aerators, Low Flow Showerheads, Water Heater Pipe Wrap, Caulking, Draft Proofing, Outlet Gaskets, Window Film	8	8	FEI	207	1.0%	122	0.4%	81	0.3%
											FEVI	53	1.8%	37	0.9%	24	0.6%
											FEW	0	0.0%	0	0.0%	0	0.0%
											Total	260	1.1%	159	0.5%	105	0.3%
Energy Conservation and Assistance Program (ECAP)	4%	4%	n/a	n/a	30%	30%	Basic Stream of measures includes direct Installation of: Faucet aerators, Lo Flow Showerheads, Water Heater Pipe Wrap, Caulking, Draftproofing, Outlet Gaskets, Window Film, and Basic Draftproofing. Advanced Stream of measures includes all the above and, in some cases: Ceiling/Wall/Crawl Insulation, Advanced Draftproofing, Carbon Monoxide Detectors and Ventilation	Basic Stream of measures includes direct Installation of: Faucet aerators, Lo Flow Showerheads, Water Heater Pipe Wrap, Caulking, Draftproofing, Outlet Gaskets, Window Film, and Basic Draftproofing. Advanced Stream of measures includes all the above and, in some cases: Ceiling/Wall/Crawl Insulation, Advanced Draftproofing, Carbon Monoxide Detectors and Ventilation	13	13	FEI	217	1.0%	1,507	5.1%	2,210	7.1%
											FEVI	24	0.8%	167	4.2%	246	6.1%
											FEW	0	0.0%	0	0.0%	0	0.0%
											Total	241	1.0%	1,675	4.9%	2,456	6.9%
Low Income Space Heat Top-Ups	n/a	5%	n/a	n/a	30%	30%	n/a	Condensing boiler, Near condensing boiler, Condensing Rooftop Unit	n/a	19.6							
											FEI	0	n/a	70	0.2%	54	0.2%
											FEVI	0		8	0.2%	6	0.1%
											FEW	0		0	0.0%	0	0.0%
											Total	0		78	0.2%	60	0.2%
Low Income Water Heating Top-Ups	n/a	1%	n/a	n/a	30%	30%	n/a	Condensing storage and volume type water heater, Near condensing storage and volume type water heater, Condensing on-demand water heater	n/a	12	FEI	0	n/a	14	0.0%	12	0.0%
											FEVI	0		2	0.0%	1	0.0%
											FEW	0		0	0.0%	0	0.0%
											Total	0		15	0.0%	13	0.0%
Non-Profit Custom Program	n/a	5%	n/a	n/a	30%	30%	n/a	Energy Study, Capital Incentives	n/a	9.6	FEI	0	n/a	285	1.0%	417	1.3%
											FEVI	0		32	0.8%	46	1.1%
											FEW	0		0	0.0%	0	0.0%
											Total	0		316	0.9%	463	1.3%
Non Program Specific Expenses											FEI	0	n/a	n/a	n/a	n/a	n/a
											FEVI	0					
											FEW	0					
											Total	0					
All Programs											**FEI**	**525**	**2.5%**	**2,039**	**6.8%**	**2,855**	**9.1%**
											FEVI	**78**	**2.6%**	**287**	**7.1%**	**323**	**8.0%**
											FEW	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**
											Total	**603**	**2.5%**	**2,324**	**6.8%**	**3,178**	**8.9%**

Innovative Technologies Program Area

Program	Free Ridership % 2012	Free Ridership % 2014-2018	Spillover % 2012	Spillover % 2014-2018	Non-energy benefits % 2012 2012	Non-energy benefits % 2012 2014-2018	Measures 2012 2012	Measures 2012 2014-2018	Lifespan of Asset (years) 2012	Lifespan of Asset (years) 2014-2018
Pilot/Demonstration Projects	n/a[1]	n/a[1]	n/a[2]	n/a[2]	n/a	n/a	AHU Coil Cleaning Pilot		n/a[6]	
							City of Courtenay Pool Heating Project		30	
							City of Vancouver Residential Solar Water Heating Pilot		25	
							Residential High-Efficiency Water Heaters	Residential High-Efficiency Water Heaters	18	18
							ENERGY STAR© 0.67 Storage Tank Water Heaters	ENERGY STAR© 0.67 Storage Tank Water Heaters	13	13
								Recirculating Demand Controls		15
								Combination Space/Water Heating Units		15
								Condensing Unit Heaters		15
								Radiant Tube Heaters		20
								Condensing Gas-Fired Ventilation Units		18
								City of Vancouver Green MURBs		n/a[5]
								Ozone Commercial Laundry		15
								De-Aerator Vent Steam Recovery		20
								Residential HVAC Zoning		25
								Thermal Bridging Measures		50
								Water Spray Kiln Misting System		15
								Occupancy Sensor for MURBs		10
								Ice Rink Efficiency		10
								Air Curtains		15
								Transpired Solar Collectors		40
								Ceramic Manufacturing Microwave Assist		30
								Catalytic Radiant Burners		10
								Fireplace Inserts		n/a[7]
								Kiln Control		15
								Heat Reflectors		18
Studies and Memberships	n/a	n/a	n/a	n/a	n/a	n/a	Thermal Performances of Building Envelope Assemblies for Mid- and High-Rise Buildings in B.C.	All Studies[3]		
							Review of Packaged Rooftop Equipment (RTU) Upgrades for DSM Utility Programs			
							Energy Savings Potential Using Occupancy Sensors			
							Geoexchange BC - Phase 1 Energy Performance Evaluation Project			
							Transpired Solar Collector Market Study			
							Pre-Feasibility Study Microwave Assist Technology			
							Pre-Feasibility Study Catalytic Radiant Burner Technology			
							CEATI Membership			

Program	Service Territory	2012 Actual Spending ($000s)	2012 % of Total Service Territory Spending	2014 Estimated Spending ($000s)	2014 % of Total Service Territory Spending	2018 Estimated Spending ($000s)	2018 % of Total Service Territory Spending	Comments
Pilot/Demonstration Projects	FEI	$224	1.1%	$808	2.7%	$886	2.8%	Please note that FEU's forecast expenditures for the 2014-2018 time horizon are higher than the actual expenditures for 2012. As explained in Exhibit B-1-1, Appendix I, Attachment I2, p. 65, pilots target technologies which are not commonly used in British Columbia and are thus subject to risks associated with technical feasibility and market prioritization. As a result, 2012 actual expenditures were lower than anticipated. For the same reason, actual expenditures for the 2014-2018 time horizon may also diverge from the projected numbers.
	FEVI	$40	1.3%	$88	2.2%	$13	0.3%	Please note that FEU forecast the ratio of expenditures in the FEVI service territory to decrease in relation to 2012 over the 2014-2018 time horizon. FEU currently project pilots for the 2014-2018 time horizon to elicit participation primarily from the FEI service territory. Scalability and Measurement and Verification requirements permitting, FEU do call for pilot participation from the FEVI service terriroty. However, pilots target technologies which are not commonly used in British Columbia and customer uptake for these technologies may vary across service territories. As a result, actual participation and expenditure ratios may diverge fromt FEU's current projections.
	FEW[4]	$0	0.0%	$0	0.0%	$0	0.0%	
	Total	$263	1.1%	$897	2.6%	$899	2.5%	
Studies and Memberships	FEI	$131	0.6%	$180	0.6%	$180	0.6%	FEU forecast an increased budget for studies for the 2014-2018 time horizon in order to meet projected research requirements for the listed measures.
	FEVI	$0	0.0%	$0	0.0%	$0	0.0%	
	FEW[4]	$0	0.0%	$0	0.0%	$0	0.0%	
	Total	$131	0.6%	$180	0.5%	$180	0.5%	
Non Program Specific Expenses	FEI	$0	0.0%	$117	0.4%	$117	0.4%	
	FEVI	$0	0.0%	$13	0.3%	$13	0.3%	
	FEW[4]	$0	0.0%	$0	0.0%	$0	0.0%	
	Total	$0	0.0%	$131	0.4%	$131	0.4%	
All Programs	**FEI**	$353	1.7%	$1,106	3.7%	$1,183	3.8%	
	FEVI	$40	1.3%	$101	2.5%	$26	0.6%	
	FEW[4]	$0	0.0%	$0	0.0%	$0	0.0%	
	Total	$394	1.7%	$1,207	3.5%	$1,210	3.4%	

Footnotes

1. In accordance with B.C. Reg. 326/2008, including amendment B.C. Reg. 228/2011, Section 1., the innovative technologies program evaluates and supports technologies which are not commonly used in British Columbia; as such, the free rider metric does not apply.
2. In accordance with B.C. Reg. 326/2008, including amendment B.C. Reg. 228/2011, Section 1., the innovative technologies program evaluates and supports technologies which are not commonly used in British Columbia; as such, the spillover metric does not apply.
3. At the time of writing, FEU do not have access to sufficient data for determining which measures will require dedicated studies rather than other types of research; as more data becomes available, FEU will list specific studies in future compliance filings for the 2014-2018 time period.
4. For the period of 2014-2018, FEW expenditures are included into FEI since historical data suggests that program participation from FEW will be negligible.
5. The City of Vancouver Green MURBs pilot targets three different technology types (mechanical ventilation controls, condensing rooftop units, and pipe insulation); these technology types have differing lifespans.
6. Coil cleaning represents a maintenance pratice whose benefits will persist as long as this maintenance is performed as required; as such, a finite lifespan does not apply.
7. At the time of writing, FEU does not have access to sufficient data to determine the measure life of the Fireplace Inserts.

Please note, all projected expenditures exclude inflation, all mismatches in expenditure totals are due to rounding.

CEO Program Area

Program	Free Ridership %		Spillover %		Non-energy benefits % 2012		Measures 2012		Lifespan of Asset (years)		Service Territory	2012		2014		2018	
	2012	2014-2018	2012	2014-2018	2012	2014-2018	2012	2014-2018	2012	2014-2018		Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending	Spending ($000s)	% of Total Service Territory Spending
Residential Education	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FEI	1,101	5.3%	881	3.0%	881	2.8%
											FEVI	171	5.7%	99	2.5%	99	2.4%
											FEW	0	n/a	10	4.2%	10	4.5%
											Total	1,272	5.4%	990	2.9%	990	2.8%
Commercial Education	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FEI	265	1.3%	401	1.3%	401	1.3%
											FEVI	23	0.8%	45	1.1%	45	1.1%
											FEW	0	n/a	5	2.1%	5	2.2%
											Total	288	1.2%	450	1.3%	450	1.3%
School Education	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FEI	450	2.2%	641	2.2%	641	2.0%
											FEVI	79	2.6%	72	1.8%	72	1.8%
											Few	0	n/a	7	3.0%	7	3.1%
											Total	529	2.2%	720	2.1%	720	2.0%
Non Program Specific Expenses											FEI	93	0.4%	214	0.7%	214	0.7%
											FEVI	18	0.6%	24	0.6%	24	0.6%
											FEW	0	n/a	2	1.0%	2	1.1%
											Total	111	0.5%	240	0.7%	240	0.7%
All Programs											**FEI**	**1,909**	**9.2%**	**2,137**	**7.2%**	**2,137**	**6.8%**
											FEVI	**291**	**9.6%**	**240**	**6.0%**	**240**	**5.9%**
											FEW	**0**	**0.0%**	**24**	**10.3%**	**24**	**10.9%**
											Total	**2,200**	**9.3%**	**2,400**	**7.1%**	**2,400**	**6.7%**

Attachment 234.9

Portfolio Level Results

Portfolio and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2012 Actual	Admin	Communications	Research/Evaluation	2012 Actual
Portfolio Level Activities					
FEI	0	3,464	0	0	3,464
FEVI	0	581	0	0	581
Total	0	4,045	0	0	4,045
Residential Sector (includes Enabling Activities)					
FEI	8,733	1,130	197	139	10,198
FEVI	832	212	36	16	1,095
Total	9,564	1,341	234	155	11,294
Low Income					
FEI	195	228	91	11	525
FEVI	45	22	10	1	78
Total	240	250	100	12	603
Commercial Sector					
FEI	3,346	343	113	143	3,945
FEVI	869	15	18	17	920
Total	4,215	359	131	160	4,865
Innovative Technologies					
FEI	92	11	258	251	353
FEVI	9	3	28	27	40
Total	102	14	286	279	394
Industrial Sector					
FEI	293	35	4	15	347
FEVI	10	0	0	0	10
Total	303	36	4	15	358
Conservation, Education, and Outreach					
FEI	0	1,346	552	11	1,909
FEVI	0	232	54	4	291
Total	0	1,578	607	15	2,200
TOTAL PORTFOLIO					
FEI	**12,659**	**6,556**	**1,215**	**570**	**20,741**
FEVI	**1,765**	**1,065**	**146**	**66**	**3,015**
Total	**14,425**	**7,623**	**1,362**	**636**	**23,759**
Total % of EEC Expenditures	**61%**	**32%**	**6%**	**3%**	**100%**

Notes
Whistler (FEW) is included in the FEI service territory
Any discrepancies due to rounding

Portfolio Level Results

Portfolio and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2014 Projected	Admin	Communications	Research/Evaluation	2014 Total
Residential Sector (includes Enabling Activities)					
FEI	6,817	1,293	918	445	9,473
FEVI	791	147	105	47	1,090
Total	7,608	1,440	1,023	492	10,563
Low Income					
FEI	1,245	894	129	38	2,306
FEVI	154	143	19	6	322
Total	1,399	1,037	148	44	2,628
Commercial Sector					
FEI	7,478	1,494	246	184	9,403
FEVI	1,447	215	27	13	1,728
Total	8,926	1,713	274	219	11,131
Innovative Technologies					
FEI	178	344	0	584	1,106
FEVI	20	38	0	43	101
Total	198	382	0	627	1,207
Industrial Sector*					
FEI	1,314	430	54	80	1,879
FEVI	132	43	5	7	189
Total	1,445	474	60	88	2,067
Conservation, Education, and Outreach					
FEI	0	1,247	715	194	2,156
FEVI	0	139	81	22	242
Total	0	1,386	796	217	2,400
Enabling Activities					
FEI	0	4,077	0	32	4,109
FEVI	0	403	0	3	406
Total	0	4,480	0	35	4,515
TOTAL PORTFOLIO					
FEI	**17,032**	**9,779**	**2,062**	**1,557**	**30,432**
FEVI	**2,544**	**1,128**	**237**	**142**	**4,079**
Total	**19,576**	**10,912**	**2,301**	**1,722**	**34,511**
Total % of EEC Expenditures	**57%**	**32%**	**7%**	**5%**	**100%**

Notes:
Whistler (FEW) is included in the FEI service territory
*Industrial expenditures differ slightly from EEC Plan due to an EEC Plan miscalculation
Other discrepancies due to rounding

Portfolio Level Results

Portfolio and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2018 Projected	Admin	Communications	Research/Evaluation	2018 Total
Residential Sector (includes Enabling Activities)					
FEI	7,143	1,254	1,507	385	10,289
FEVI	755	132	167	39	1,093
Total	7,898	1,386	1,674	424	11,382
Low Income					
FEI	1,717	1,180	169	57	3,123
FEVI	202	132	20	6	360
Total	1,919	1,312	189	63	3,483
Commercial Sector					
FEI	6,535	1,355	197	259	8,346
FEVI	1,414	216	21	55	1,706
Total	7,949	1,571	219	313	10,052
Innovative Technologies					
FEI	566	193	0	425	1,183
FEVI	2	14	0	9	26
Total	568	208	0	434	1,210
Industrial Sector*					
FEI	1,851	461	54	227	2,593
FEVI	189	46	5	22	262
Total	2,041	507	59	249	2,856
Conservation, Education, and Outreach					
FEI	0	1,247	715	194	2,156
FEVI	0	139	81	22	242
Total	0	1,386	796	216	2,400
Enabling Activities					
FEI	0	3,925	0	32	3,972
FEVI	0	405	0	3	393
Total	0	4,330	0	35	4,365
TOTAL PORTFOLIO					
FEI	**17,812**	**9,616**	**2,642**	**1,578**	**31,663**
FEVI	**2,562**	**1,084**	**294**	**157**	**4,082**
Total	**20,375**	**10,700**	**2,937**	**1,734**	**35,748**
Total % of EEC Expenditures	**57%**	**30%**	**8%**	**5%**	**100%**

Notes:
Whistler (FEW) is included in the FEI service territory
*Industrial expenditures differ slightly from EEC Plan due to an EEC Plan miscalculation
Other discrepancies due to rounding

Residential Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2012 Actual	Admin	Communications	Research/E valuation	
Non Program Specific Expenses					
FEI	0	224	0	0	224
FEVI	0	59	0	0	59
Total	0	283	0	0	283
ENERGY STAR® Domestic Hot Water "DHW" Technologies					
FEI	59	13	22	4	98
FEVI	30	3	1	1	36
Total	89	17	23	4	133
Enerchoice Fireplace Program					
FEI	714	143	59	0	917
FEVI	234	43	15	0	291
Total	948	186	74	0	1,208
"Give your Furnace/Fireplace Some TLC" – Service Campaign					
FEI	428	126	35	13	602
FEVI	81	18	4	1	105
Total	510	144	39	14	706
LiveSmart BC - April 1, 2011 through March 31, 2012					
FEI	3,506	38	27	50	3,621
FEVI	243	4	6	3	256
Total	3,749	42	33	53	3,877
LiveSmart BC - April 1, 2012 through March 31, 2013 1					
FEI	976	0	0	0	976
FEVI	88	0	0	0	88
Total	1,064	0	0	0	1,064
ENERGY STAR® Washers and Other Measures for DHW Conservation					
FEI	561	45	2	0	608
FEVI	48	3	0	0	51
Total	610	48	2	0	660
Furnace Replacement Pilot Program					
FEI	2,322	245	32	53	2,651
FEVI	103	11	7	6	127
Total	2,425	256	40	58	2,779
New Construction - EnerGuide 80 and Energy Efficient Appliances					
FEI	167	5	20	12	204
FEVI	5	0	2	1	7
Total	171	5	22	13	212
Enabling Activities					
FEI	0	267	0	7	274
FEVI	0	70	0	4	75
Total	0	337	0	12	348
On-Bill Financing					
FEI	0	24	0	0	24
FEVI	0	0	0	0	0
Total	0	24	0	0	24
ALL PROGRAMS					
FEI	**8,733**	**1,130**	**197**	**139**	**10,198**
FEVI	**832**	**212**	**36**	**16**	**1,095**
Total	**9,564**	**1,341**	**234**	**155**	**11,294**
Total % of Residential Expenditures	**85%**	**12%**	**2%**	**1%**	**100%**

Residential Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2014 Projected	Admin	Communications	Research/Evaluation	
Non Program Specific Expenses					
FEI	0	491	0	0	491
FEVI	0	49	0	0	49
Total	0	540	0	0	540
Energy Efficient Home Performance Program					
FEI	860	138	134	134	1,266
FEVI	86	14	13	13	126
FEW	10	2	1	1	14
Total	956	154	148	148	1,406
Furnace Replacement Program					
FEI	2,686	222	44	68	3,020
FEVI	269	22	4	7	302
FEW	30	2	0	1	33
Total	2,985	246	48	76	3,355
Enerchoice Fireplace Program					
FEI	876	145	80	41	1,142
FEVI	208	35	19	10	272
FEW	11	2	1	1	15
Total	1,095	182	100	52	1,429
Appliance Service Program					
FEI	321	49	23	18	411
FEVI	32	5	2	2	41
FEW	4	1	0	0	5
Total	357	55	25	20	457
ENERGY STAR® Water Heater Program					
FEI	865	32	45	45	987
FEVI	86	3	5	5	99
FEW	10	0	1	1	12
Total	961	35	51	51	1,098
Low Flow Fixtures					
FEI	171	36	45	9	261
FEVI	17	4	5	1	27
FEW	2	0	1	0	3
Total	190	40	51	10	291
New Home Program					
FEI	763	19	100	51	933
FEVI	76	2	10	5	93
FEW	8	0	1	1	10
Total	847	21	111	57	1,036
New Technologies Program					
FEI	172	20	22	22	236
FEVI	17	2	2	2	23
FEW	2	0	0	0	2
Total	191	22	24	24	261
Customer Engagement Tool for Conservation Behaviours					
FEI	0	99	405	16	520
FEVI	0	11	45	2	58
FEW	0	0	0	0	0
Total	0	110	450	18	578
Financing Pilot					
FEI	26	35	15	36	112
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	26	35	15	36	112
ALL PROGRAMS					
FEI	**6,817**	**1,293**	**918**	**445**	**9,473**
FEVI	**791**	**147**	**105**	**47**	**1,090**
Total	**7,608**	**1,440**	**1,023**	**492**	**10,563**
Total % of Residential Expenditures	**72%**	**14%**	**10%**	**5%**	**100%**

Residential Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			
	2018 Projected	Admin	Communications	Research/ Evaluation	Total
Non Program Specific Expenses					
FEI	0	491	0	0	491
FEVI	0	49	0	0	49
Total	0	540	0	0	540
Energy Efficient Home Performance Program					
FEI	1,228	138	134	134	1,634
FEVI	123	14	13	13	163
FEW	14	2	1	1	18
Total	1,365	154	148	148	1,815
Furnace Replacement Program					
FEI	2,686	222	44	44	2,996
FEVI	269	22	4	4	299
FEW	30	2	0	0	32
Total	2,985	246	48	48	3,327
Enerchoice Fireplace Program					
FEI	482	87	59	40	668
FEVI	114	21	14	10	159
FEW	6	1	1	1	9
Total	602	109	74	51	836
Appliance Service Program					
FEI	321	49	23	18	411
FEVI	32	5	2	2	41
FEW	4	1	0	0	5
Total	357	55	25	20	457
ENERGY STAR® Water Heater Program					
FEI	1,144	27	46	18	1,235
FEVI	114	3	5	2	124
FEW	13	0	1	0	14
Total	1,271	30	52	20	1,373
Low Flow Fixtures					
FEI	171	36	45	9	261
FEVI	17	4	5	1	27
FEW	2	0	1	0	3
Total	190	40	51	10	291
New Home Program					
FEI	599	12	63	32	706
FEVI	60	1	6	3	70
FEW	7	0	1	0	8
Total	666	13	70	35	784
New Technologies Program					
FEI	257	24	22	22	325
FEVI	26	2	2	2	32
FEW	3	0	0	0	3
Total	286	26	24	24	360
Customer Engagement Tool for Conservation Behaviours					
FEI	0	99	1,046	16	1,161
FEVI	0	11	116	2	129
FEW	0	0	0	0	0
Total	0	110	1,162	18	1,290
Financing Pilot					
FEI	176	63	20	50	309
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	176	63	20	50	309
ALL PROGRAMS					
FEI	**7,143**	**1,254**	**1,507**	**385**	**10,289**
FEVI	**755**	**132**	**167**	**39**	**1,093**
Total	**7,898**	**1,386**	**1,674**	**424**	**11,382**
Total % of Residential Expenditures	**69%**	**12%**	**15%**	**4%**	**100%**

Low Income Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2012 Actual	Admin	Communications	Research/Evaluation	Total
Non Program Specific Expenses					
FEI	0	11	0	0	11
FEVI	0	0	0	0	0
Total	0	11	0	0	11
Residential Energy Efficiency Works (REnEW)					
FEI	0	85	4	2	91
FEVI	0	0	0	0	0
Total	0	85	4	2	91
Energy Saving Kit (ESK)					
FEI	120	51	35	0	207
FEVI	36	13	5	0	53
Total	156	64	39	0	260
Energy Conservation Assistance Program (ECAP)					
FEI	75	81	52	9	217
FEVI	9	9	5	1	24
Total	84	90	57	10	241
ALL PROGRAMS					
FEI	**195**	**228**	**91**	**11**	**525**
FEVI	**45**	**22**	**10**	**1**	**78**
Total	**240**	**250**	**100**	**12**	**603**
Total % of Low Income Expenditures	**40%**	**42%**	**17%**	**2%**	**100%**

Low Income Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2014 Projected	Admin	Communi cations	Research/Eval uation	
Non Program Specific Expenses					
FEI	0	268	0	0	268
FEVI	0	37	0	0	37
Total	0	305	0	0	305
Energy Savings Kit					
FEI	72	30	19	2	123
FEVI	24	7	5	1	37
FEW	0	0	0	0	0
Total	96	37	24	3	160
Energy Conservation Assistance Program					
FEI	901	485	91	30	1,507
FEVI	100	54	10	3	167
FEW	0	0	0	0	0
Total	1,001	539	101	33	1,674
REnEW					
FEI	0	36	2	2	40
FEVI	0	36	2	2	40
FEW	0	0	0	0	0
Total	0	72	4	4	80
Low Income Space Heat Top-Ups					
FEI	58	5	7	0	70
FEVI	6	1	1	0	8
FEW	0	0	0	0	0
Total	64	6	8	0	78
Low Income Water Heating Top-Ups					
FEI	10	2	2	0	14
FEVI	1	0	0	0	1
FEW	0	0	0	0	0
Total	11	2	2	0	15
Non-Profit Custom Program					
FEI	204	68	8	4	284
FEVI	23	8	1	0	32
FEW	0	0	0	0	0
Total	227	76	9	4	316
ALL PROGRAMS					
FEI	**1,245**	**894**	**129**	**38**	**2,306**
FEVI	**154**	**143**	**19**	**6**	**322**
Total	**1,399**	**1,037**	**148**	**44**	**2,628**
Total % of Low Income Expenditures	**53%**	**39%**	**6%**	**2%**	**100%**

Low Income Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2018 Projected	Admin	Communi cations	Research/ Evaluation	
Non Program Specific Expenses					
FEI	0	268	0	0	268
FEVI	0	37	0	0	37
Total	0	305	0	0	305
Energy Savings Kit					
FEI	47	20	12	1	80
FEVI	16	5	3	0	24
FEW	0	0	0	0	0
Total	63	25	15	1	104
Energy Conservation Assistance Program					
FEI	1,319	713	134	45	2,211
FEVI	147	79	15	5	246
FEW	0	0	0	0	0
Total	1,466	792	149	50	2,457
REnEW					
FEI	0	73	4	4	81
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	73	4	4	81
Low Income Space Heat Top-Ups					
FEI	45	4	5	1	55
FEVI	5	0	1	0	6
FEW	0	0	0	0	0
Total	50	4	6	1	61
Low Income Water Heating Top-Ups					
FEI	7	2	2	0	11
FEVI	1	0	0	0	1
FEW	0	0	0	0	0
Total	8	2	2	0	12
Non-Profit Custom Program					
FEI	299	100	12	6	417
FEVI	33	11	1	1	46
FEW	0	0	0	0	0
Total	332	111	13	7	463
ALL PROGRAMS					
FEI	**1,717**	**1,180**	**169**	**57**	**3,123**
FEVI	**202**	**132**	**20**	**6**	**360**
Total	**1,919**	**1,312**	**189**	**63**	**3,483**
Total % of Low Income Expenditures	**55%**	**38%**	**5%**	**2%**	**100%**

Commercial Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2012 Actual	Admin	Communications	Research/ Evaluation	2012 Actual
Non Program Specific Expenses					
FEI	0	157	0	0	157
FEVI	0	4	0	0	4
Total	0	161	0	0	161
Efficient Boiler Program					
New					
FEI	67	1	1	2	71
FEVI	28	0	0	1	29
Retrofit					
FEI	1,176	21	24	55	1,276
FEVI	402	0	3	8	413
Total	1,673	23	28	66	1,790
Light Commercial Boiler Program					
New					
FEI	3	0	0	0	3
FEVI	0	0	0	0	0
Retrofit					
FEI	6	0	1	0	7
FEVI	1	0	0	0	1
Total	10	0	1	0	11
Efficient Commercial Water Heater Program					
New					
FEI	56	0	7	2	65
FEVI	2	0	1	0	3
Retrofit					
FEI	93	1	22	6	121
FEVI	13	0	2	0	15
Total	163	1	32	7	204
Commercial Energy Assessment Program					
FEI	412	17	3	0	432
FEVI	59	5	0	0	64
Total	471	22	4	0	497
Spray Valve Program					
New					
FEI	0	0	0	0	0
FEVI	0	0	0	0	0
Retrofit					
FEI	9	11	0	0	20
FEVI	2	2	0	0	4
Total	11	13	0	0	23
Commercial Custom Design Program					
New					
FEI	13	1	5	0	19
FEVI	0	0	1	0	1
Retrofit					
FEI	34	7	1	0	41
FEVI	11	3	0	0	14
Total	58	11	6	0	74
Continuous Optimization Program					
FEI	739	1	0	0	740
FEVI	159	0	0	0	159
Total	898	1	0	0	899
Efficiency à la Carte (Commercial Kitchen Program)					
New					
FEI	5	0	48	0	53
FEVI	5	0	7	0	12
Retrofit					
FEI	0	0	0	0	0
FEVI	10	0	4	0	13
Total	19	0	59	0	79
MURB Program					
New					
FEI	0	0	0	0	0
FEVI	0	0	0	0	0
Retrofit					
FEI	4	0	0	0	4
FEVI	0	0	0	0	0
Total	4	0	0	0	4
Fireplace Timers Pilot Program					
FEI	0	0	0	9	9
FEVI	0	0	0	1	1
Total	0	0	0	10	10
Radiant Tube Heaters Pilot Program					
FEI	0	0	0	1	1
FEVI	0	0	0	0	0
Total	0	0	0	1	1
EnerTracker Program					
FEI	0	122	1	0	122
FEVI	0	0	0	0	0
Total	0	122	1	0	122
Energy Specialist Program					
FEI	729	3	0	68	800
FEVI	180	1	0	8	188
Total	909	3	0	76	989
PSECA Program					
FEI	0	2	0	0	2
FEVI	0	0	0	0	0
Total	0	2	0	0	2
ALL PROGRAMS					
FEI	**3,346**	**343**	**113**	**143**	**3,945**
FEVI	**869**	**15**	**18**	**17**	**920**
Total	**4,215**	**359**	**131**	**160**	**4,865**
Total % of Commercial Expenditures	**87%**	**7%**	**3%**	**3%**	**100%**

Commercial Program Area Results

Program and Service Territory	Incentives	Non-Incentives			All Spending
	Expenditures ($000s)				
	2014 Projected	Admin	Communi cations	Research/ Evaluation	2014 Projected
Non Program Specific Expenses					
FEI	0	935	0	0	935
FEVI	0	165	0	0	165
Total	0	1,100	0	0	1,100
Space Heat Program					
FEI	1,274	16	28	11	1,329
FEVI	430	2	3	4	439
FEW	17	0	0	0	18
Total	1,722	18	32	15	1,786
Water Heating Program					
FEI	170	1	20	13	204
FEVI	28	0	2	2	32
FEW	2	0	0	0	2
Total	200	1	22	15	238
Commercial Food Service Program					
FEI	240	4	107	13	364
FEVI	27	1	12	2	42
FEW	3	0	1	0	4
Total	270	5	120	15	410
Customized Equipment Upgrade Program*					
FEI	2,582	220	64	19	2,885
FEVI	467	25	7	3	502
FEW	63	2	0	0	65
Total	3,112	247	71	22	3,452
EnerTracker Program					
FEI	296	99	1	13	409
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	296	99	1	13	409
Continuous Optimization Program**					
FEI	1,181	142	21	12	1,356
FEVI	133	16	3	1	153
FEW	13	0	0	0	13
Total	1,327	158	24	13	1,522
Commercial Energy Assessment Program					
FEI	337	57	4	12	410
FEVI	38	6	0	1	45
FEW	4	1	0	0	5
Total	379	64	4	13	460
Energy Specialist Program					
FEI	1,296	14	0	86	1,396
FEVI	324	4	0	22	350
FEW	0	0	0	0	0
Total	1,620	18	0	108	1,746
Mechanical Insulation Pilot					
FEI	0	3	0	5	8
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	3	0	5	8
ALL PROGRAMS					
FEI	**7,478**	**1,494**	**246**	**184**	**9,403**
FEVI	**1,447**	**215**	**27**	**13**	**1,728**
Total	**8,926**	**1,713**	**274**	**219**	**11,131**
Total % of Commercial Expenditures	**80%**	**15%**	**2%**	**2%**	**100%**

Notes:

*Increased 2014 spend a result of shifting redcued spending in the Continuous Optimization Program budget to the Customized Equipment Upgrade Program (Commercial Custom Design Program).

**The Continuous Optimization Program budget as presented in Exhibit B-1-1, FEI 2014-2018 PBR, Appendix I-2 has since been reduced. The long-run marginal cost of electricity negatively impacted BC Hydro's cost-effectiveness test, which in turn caused BC Hydro toclose the program to new participants in 2013. Given that new participants will no longer be accepted into the program beyond 2013, the budget has been reduced accordingly.

Commercial Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2018 Projected	Admin	Communi cations	Research/ Evaluation	2018 Projected
Non Program Specific Expenses					
FEI	0	935	0	0	935
FEVI	0	165	0	0	165
Total	0	1,100	0	0	1,100
Space Heat Program					
FEI	1,520	16	40	56	1,632
FEVI	513	2	5	19	539
FEW	21	0	0	1	22
Total	2,054	18	45	76	2,193
Water Heating Program					
FEI	234	1	20	31	286
FEVI	38	0	2	5	45
FEW	3	0	0	0	3
Total	275	1	22	36	334
Commercial Food Service Program					
FEI	436	4	80	45	565
FEVI	49	1	9	5	64
FEW	5	0	1	1	7
Total	490	5	90	51	636
Customized Equipment Upgrade Program*					
FEI	2,309	179	52	15	2,555
FEVI	417	21	5	2	445
FEW	56	1	0	0	57
Total	2,782	201	58	16	3,057
EnerTracker Program					
FEI	0	0	0	0	0
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	0	0	0	0
Continuous Optimization Program**					
FEI	311	142	0	12	465
FEVI	35	16	0	1	52
FEW	3	0	0	0	3
Total	349	158	0	13	520
Commercial Energy Assessment Program					
FEI	337	62	4	12	415
FEVI	38	7	0	1	46
FEW	4	1	0	0	5
Total	379	70	4	13	466
Energy Specialist Program					
FEI	1,296	14	0	86	1,396
FEVI	324	4	0	22	350
FEW	0	0	0	0	0
Total	1,620	18	0	108	1,746
Mechanical Insulation Pilot					
FEI	0	0	0	0	0
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	0	0	0	0
ALL PROGRAMS					
FEI	**6,535**	**1,355**	**197**	**259**	**8,346**
FEVI	**1,414**	**216**	**21**	**55**	**1,706**
Total	**7,949**	**1,571**	**219**	**313**	**10,052**
Total % of Commercial Expenditures	**79%**	**16%**	**2%**	**3%**	**100%**

Notes:

*Increased 2014 spend a result of shifting redcued spending in the Continuous Optimization Program budget to the Customized Equipment Upgrade Program (Commercial Custom Design Program).

**The Continuous Optimization Program budget as presented in Exhibit B-1-1, FEI 2014-2018 PBR, Appendix I-2 has since been reduced. The long-run marginal cost of electricity negatively impacted BC Hydro's cost-effectiveness test, which in turn caused BC Hydro toclose the program to new participants in 2013. Given that new participants will no longer be accepted into the program beyond 2013, the budget has been reduced accordingly.

Innovative Technologies Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2012 Actual	Admin	Communications	Research/ Evaluation	2012 Actual
Pilot/Demonstration Projects					
FEI	92	4	7	121	224
FEVI	9	2	1	27	40
Total	102	6	8	148	263
Studies and Memberships					
FEI	0	0	0	131	131
FEVI	0	0	0	0	0
Total	0	0	0	131	131
ALL PROGRAMS					
FEI	**92**	**11**	**258**	**251**	**353**
FEVI	**9**	**3**	**28**	**27**	**40**
Total	**102**	**14**	**286**	**279**	**394**
Total % of Innovative Technologies Expenditures	**26%**	**4%**	**73%**	**71%**	**100%**

Innovative Technologies Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2014 Actual	Admin	Communications	Research/ Evaluation	2014 Projected
Non Program Specific Expenses					
FEI	0	117	0	0	117
FEVI	0	13	0	0	13
FEW	0	0	0	0	0
Total	0	131	0	0	131
Pilot Projects					
FEI	178	226	0	404	808
FEVI	20	25	0	43	88
FEW	0	0	0	0	0
Total	198	252	0	447	897
Prefeasibility Studies					
FEI	0	0	0	180	180
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	0	0	180	180
ALL PROGRAMS					
FEI	**178**	**344**	**0**	**584**	**1,106**
FEVI	**20**	**38**	**0**	**43**	**101**
Total	**198**	**382**	**0**	**627**	**1,207**
Total % of Innovative Technologies Expenditures	**16%**	**32%**	**0%**	**52%**	**100%**

Innovative Technologies Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2018 Actual	Admin	Communications	Research/ Evaluation	2018 Projected
Non Program Specific Expenses					
FEI	0	117	0	0	117
FEVI	0	13	0	0	13
FEW	0	0	0	0	0
Total	0	131	0	0	131
Pilot Projects					
FEI	566	76	0	245	886
FEVI	2	1	0	9	13
FEW	0	0	0	0	0
Total	568	77	0	254	899
Prefeasibility Studies					
FEI	0	0	0	180	180
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	0	0	180	180
ALL PROGRAMS					
FEI	**566**	**193**	**0**	**425**	**1,183**
FEVI	**2**	**14**	**0**	**9**	**26**
Total	**568**	**208**	**0**	**434**	**1,210**
Total % of Innovative Technologies Expenditures	**47%**	**17%**	**0%**	**36%**	**100%**

Industrial Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2012 Actual	Admin	Communications	Research/Evaluation	2012 Actual
Non Program Specific Expenses					
FEI	0	8	0	0	8
FEVI	0	0	0	0	0
Total	0	8	0	0	8
Technology Retrofit Program					
FEI	250	1	3	15	269
FEVI	0	0	0	0	0
Total	250	1	3	15	269
Energy Audit & Analysis Program					
FEI	43	0	1	0	44
FEVI	10	0	0	0	10
Total	53	1	1	0	55
Process Heat Program					
FEI	0	20	0	0	20
FEVI	0	0	0	0	0
Total	0	20	0	0	20
Customer Energy Analysis					
FEI	0	5	0	0	5
FEVI	0	0	0	0	0
Total	0	5	0	0	5
ALL PROGRAMS					0
FEI	**293**	**35**	**4**	**15**	**347**
FEVI	**10**	**0**	**0**	**0**	**10**
Total	**303**	**36**	**4**	**15**	**358**
Total % of Industrial Expenditures	**85%**	**10%**	**1%**	**4%**	**100%**

Industrial Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2014 Projected	Admin	Communications	Research/Evaluation	2014 Projected
Non Program Specific Expenses					
FEI	0	238	0	0	238
FEVI	0	24	0	0	24
Total	0	262	0	0	262
Industrial Optimization Program*					
FEI	1,127	166	30	55	1,378
FEVI	113	17	3	5	138
FEW	13	2	0	1	16
Total	1,252	185	33	61	1,531
Specialized Industrial Process Technology Program					
FEI	174	24	24	24	246
FEVI	19	2	2	2	27
FEW	0	0	0	0	1
Total	193	27	27	27	274
ALL PROGRAMS					
FEI	**1,314**	**430**	**54**	**80**	**1,879**
FEVI	**132**	**43**	**5**	**7**	**189**
Total	**1,445**	**474**	**60**	**88**	**2,067**
Total % of Industrial Expenditures	**70%**	**23%**	**3%**	**4%**	**100%**

*Miscalculated in EEC Plan

Industrial Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2018 Projected	Admin	Communications	Research/Evaluation	2018 Projected
Non Program Specific Expenses					
FEI	0	238	0	0	238
FEVI	0	24	0	0	24
Total	0	262	0	0	262
Industrial Optimization Program*					
FEI	1,334	197	30	201	1,762
FEVI	133	20	3	20	176
FEW	15	2	0	2	19
Total	1,483	219	33	223	1,958
Specialized Industrial Process Technology Program					
FEI	502	24	24	24	574
FEVI	56	2	2	2	62
FEW	0	0	0	0	0
Total	558	26	26	26	636
ALL PROGRAMS					0
FEI	**1,851**	**461**	**54**	**227**	**2,593**
FEVI	**189**	**46**	**5**	**22**	**262**
Total	**2,041**	**507**	**59**	**249**	**2,856**
Total % of Industrial Expenditures	**71%**	**18%**	**2%**	**9%**	**100%**

*Miscalculated in EEC Plan

CEO Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			All Spending
	2012 Actual	Admin	Communications	Research/ Evaluation	2012 Actual
Residential and General Public					
Residential Mass Education on Conservation and Energy Literacy					
FEI	0	21	211	0	232
FEVI	0	1	27	0	28
Total	0	22	238	0	260
Residential Home Shows and Community Events Outreach					
FEI	0	443	98	0	541
FEVI	0	51	10	0	61
Total	0	494	108	0	602
Canadian Home Builders' Association Promotions and Support					
FEI	0	21	1	0	22
FEVI	0	15	1	0	17
Total	0	36	3	0	39
Residential Outreach Education Tools					
FEI	0	49	41	3	93
FEVI	0	6	9	3	18
Total	0	55	50	6	111
Energy Champion Program					
FEI	0	122	130	0	252
FEVI	0	59	0	0	59
Total	0	181	130	0	311
Home Efficiency Measures					
FEI	0	17	0	0	17
FEVI	0	0	0	0	0
Total	0	17	0	0	17
Municipal Partnerships – Other					
FEI	0	0	0	8	8
FEVI	0	0	0	1	1
Total	0	0	0	9	9
Commercial Customers					
Medium-Large Commercial Education Sessions					
FEI	0	39	0	0	39
FEVI	0	9	0	0	9
Total	0	48	0	0	48
Small Commercial Education and Outreach					
FEI	0	62	6	0	68
FEVI	0	7	0	0	7
Total	0	69	6	0	75
Commercial Trade Shows and Association Events					
FEI	0	63	13	0	76
FEVI	0	4	0	0	4
Total	0	67	13	0	80
Behaviour Programs - Online Community Site					
FEI	0	67	0	0	67
FEVI	0	0	0	0	0
Total	0	67	0	0	67
Behaviour Programs - Energy Specialists					
FEI	0	8	6	0	14
FEVI	0	3	0	0	3
Total	0	11	6	0	16
Conservation Assistance					
Conservation Assistance - Education and Outreach					
FEI	0	29	0	0	29
FEVI	0	5	0	0	5
Total	0	34	0	0	34
School Outreach					
School Programs: Class and Online Curriculum					
FEI	0	0	9	0	9
FEVI	0	0	4	0	4
Total	0	0	13	0	13
School Programs: K-12 In-Class Programs and Presentations					
FEI	0	344	0	0	344
FEVI	0	68	0	0	68
Total	0	412	0	0	412
School Programs: K-12 Home Efficiency Measures					
FEI	0	1	0	0	1
FEVI	0	0	0	0	0
Total	0	1	0	0	1
School Programs: Post Secondary					
FEI	0	59	37	0	96
FEVI	0	4	3	0	7
Total	0	63	40	0	103
ALL PROGRAMS					
FEI	**0**	**1,346**	**552**	**11**	**1,909**
FEVI	**0**	**232**	**54**	**4**	**291**
Total	**0**	**1,578**	**607**	**15**	**2,200**
Total % of CEO Expenditures	**0%**	**72%**	**28%**	**1%**	**100%**

CEO Program Area Results

Program and Service Territory	Incentives: 2014 Projected	Non-Incentives: Admin	Non-Incentives: Communications	Non-Incentives: Research/Evaluation	Total
	Expenditures ($000s)				
Non Program Specific Expenses					
FEI	0	216	0	0	216
FEVI	0	24	0	0	24
Total	0	240	0	0	240
Residential Education Program					
FEI	0	396	396	88	880
FEVI	0	45	45	10	100
FEW	0	4	4	1	9
Total	0	445	445	100	990
Commercial Education Program					
FEI	0	240	120	40	400
FEVI	0	27	14	5	46
FEW	0	3	1	0	4
Total	0	270	135	45	450
School Education Program					
FEI	0	384	192	64	640
FEVI	0	43	22	7	72
FEW	0	4	2	1	7
Total	0	431	216	72	720
ALL PROGRAMS					
FEI	**0**	**1,247**	**715**	**194**	**2,156**
FEVI	**0**	**139**	**81**	**22**	**242**
Total	**0**	**1,386**	**796**	**217**	**2,400**
Total % of CEO Expenditures	**0%**	**58%**	**33%**	**9%**	**100%**

CEO Program Area Results

Program and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2018 Projected	Admin	Communications	Research/Evaluation	
Non Program Specific Expenses					
FEI	0	216	0	0	216
FEVI	0	24	0	0	24
Total	0	240	0	0	240
Residential Education Program					
FEI	0	396	396	88	880
FEVI	0	45	45	10	100
FEW	0	4	4	1	9
Total	0	445	445	99	990
Commercial Education Program					
FEI	0	240	120	40	400
FEVI	0	27	14	5	46
FEW	0	3	1	0	4
Total	0	270	135	45	450
School Education Program					
FEI	0	384	192	64	640
FEVI	0	43	22	7	72
FEW	0	4	2	1	7
Total	0	431	216	72	720
ALL PROGRAMS					
FEI	**0**	**1,247**	**715**	**194**	**2,156**
FEVI	**0**	**139**	**81**	**22**	**242**
Total	**0**	**1,386**	**796**	**216**	**2,400**
Total % of CEO Expenditures	**0%**	**58%**	**33%**	**9%**	**100%**

Portfolio Level Activities

Activity and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2012 Actual	Admin	Communications	Research/ Evaluation	
Portfolio Level Activities					
FEI	0	3,464	0	0	3,464
FEVI	0	581	0	0	581
Total	0	4,045	0	0	4,045
ALL PROGRAMS					
FEI	**0**	**3,464**	**0**	**0**	**3,464**
FEVI	**0**	**581**	**0**	**0**	**581**
Total	**0**	**4,045**	**0**	**0**	**4,045**
Total % of Portfolio Level Expenditures	**0%**	**100%**	**0%**	**0%**	**100%**

Enabling Activities

Activity Profiles and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2014 Projected	Admin	Communications	Research/ Evaluation	
EEC Labour					
Total	0	3,500	0	0	3,500
Efficiency Partners Program					
Total	0	330	150	20	500
Codes and Standards					
Total	0	35	0	0	35
TrakSmart Maintenance					
Total	0	80	0	0	80
Conservation Potential Review*					
Total	0	0	0	0	0
Residential End-Use Study**					
Total	0	0	0	0	0
Commercial End-Use Study***					
Total	0	0	0	0	0
Market Saturation Study****					
Total	0		0	150	150
New Homes Study*****					
Total	0	0	0	0	0
Home Energy Efficiency Web Portal					
Total	0	100	0	0	100
Energy Management Education Funding					
Total	0	150	0	0	150
ALL PROGRAMS					
Total	**0**	**4,195**	**150**	**170**	**4,515**
Total % of Enabling Activities Expenditures	**0%**	**93%**	**3%**	**4%**	**100%**

Notes:
*Conservation Potential Review will be a one-time Research/Evaluation expenditure of $500,000 planned for 2015
**Residential End-Use Study will be a one-time Research/Evaluation expenditure of $55,000 planned for 2016
***Commercial End-Use Study will be a one-time Research/Evaluation expenditure of $30,000 planned for 2017
****Market Saturation expenditure of $300,000 was split evenly between implementation years 2014 and 2015
*****New Homes Study will be a one-time Research/Evaluation expenditure of $30,000 planned for 2017

Enabling Activities

Activity Profiles and Service Territory	Expenditures ($000s)				
	Incentives	Non-Incentives			Total
	2018 Projected	Admin	Communications	Research/ Evaluation	
EEC Labour					
Total	0	3,500	0	0	3,500
Efficiency Partners Program					
Total	0	330	150	20	500
Codes and Standards					
Total	0	35	0	0	35
TrakSmart Maintenance					
Total	0	80	0	0	80
Conservation Potential Review*					
Total	0	0	0	0	0
Residential End-Use Study**					
Total	0	0	0	0	0
Commercial End-Use Study***					
Total	0	0	0	0	0
Market Saturation Study****					
Total	0	0	0	0	0
New Homes Study*****					
Total	0	0	0	0	0
Home Energy Efficiency Web Portal					
Total	0	100	0	0	100
Energy Management Education Funding					
Total	0	150	0	0	150
ALL PROGRAMS					
Total	**0**	**4,195**	**150**	**20**	**4,365**
Total % of Enabling Activities Expenditures	**0%**	**96%**	**3%**	**0%**	**100%**

Notes:

*Conservation Potential Review will be a one-time Research/Evaluation expenditure of $500,000 planned for 2015

**Residential End-Use Study will be a one-time Research/Evaluation expenditure of $55,000 planned for 2016

***Commercial End-Use Study will be a one-time Research/Evaluation expenditure of $30,000 planned for 2017

****Market Saturation expenditure of $300,000 was split evenly between implementation years 2014 and 2015

*****New Homes Study will be a one-time Research/Evaluation expenditure of $30,000 planned for 2017

Attachment 235.3

NAVIGANT

Custom Free Ridership and Participant Spillover Jurisdictional Review

Prepared for:
Sub-Committee of the Ontario
Technical Evaluation Committee

unionGas
A Spectra Energy Company

ENBRIDGE

May 29, 2013

Prepared by:
Debbie Brannan, Dan Violette, Ken Seiden,
Jane Hummer, and Jeff Erickson

Navigant Consulting, Inc.
1375 Walnut Street, Suite 200
Boulder, CO 80302
303.728.2500
www.navigant.com

Acknowledgements

The authors wish to acknowledge Melinda Clarke and Leslie Kulperger of Union Gas Limited and Ravi Sigurdson and Marc Hull-Jacquin of Enbridge Gas Distribution for their guidance, assistance, and support of this work. The authors also wish to acknowledge Jay Shepherd and Bob Wirtshafter, independent members of the sub-committee of Ontario's Technical Evaluation Committee who provided thoughtful feedback and direction on earlier drafts of this report. The authors appreciate the opportunity to work with such a knowledgeable team.

NAVIGANT

Table of Contents

Tables

Figures

Executive Summary

Union Gas Limited (Union) and Enbridge Gas Distribution (Enbridge) have delivered Demand Side Management (DSM) initiatives since 1997 and 1995, respectively, including programs that involve custom projects in the commercial and industrial (C&I) sectors. In 2007-2008, Summit Blue Consulting (now part of Navigant's Energy Practice) conducted the first attribution study of Union and Enbridge's custom C&I programs to evaluate free ridership (FR) and spillover effects. After the study, the Ontario Energy Board (OEB) approved the FR adjustment, but did not approve the spillover factor. Since that time, there have been a host of program environment changes, including economic conditions, energy prices, advances in technology, as well as changes in the design and delivery of the custom programs. As a result, Ontario's Technical Evaluation Committee (TEC) is prioritizing updates to FR and spillover adjustment factors as part of its mandate.

This report provides information to support a sub-committee of Ontario's TEC in its deliberations on the appropriate approach to Net-to-Gross (NTG) values in Ontario. Through a jurisdictional review of the approach to net savings, and a review of researched NTG values for programs comparable to Union and Enbridge's custom C&I gas programs, Navigant provides an assessment of the various approaches to NTG.

ES 1. Report Objectives

There are a range of options for NTG that could be adopted for natural gas DSM programs in Ontario, from transferring NTG values from similar jurisdictions and programs to conducting research to estimate a NTG value.

The objective of this report is to provide information to assist the TEC sub-committee in their determination on the appropriate approach to NTG for DSM programs in Ontario, and not to provide a specific recommendation. While this report is not comprehensive in addressing all potential considerations, such as other benefits of accurate (costs of inaccurate) NTG values, it provides important information relevant to the discussion. In addition to summarizing the regulatory and methodological approach taken by other jurisdictions, and summarizing NTG values for programs with characteristics similar to Union and Enbridge's custom C&I programs, Navigant provides insight into the risks associated with inaccurate NTG values and the approximate cost of mitigating those risks.

ES 2. Key Findings

To achieve the objective of this report, Navigant (1) reviewed the approach to net savings across a wide array of jurisdictions in the United States and Canada to identify trends in the regulatory and methodological approach to net savings, (2) conducted a review of researched NTG values of non-residential gas programs in selected jurisdictions, and (3) conducted a decision analysis to assess the options for NTG. Key findings are presented for each of these.

Approach to Net Savings

Navigant conducted research to provide a summary of the regulatory and methodological approach to net savings adopted by jurisdictions across North America. In total, Navigant reviewed the approach to net savings taken by 42 jurisdictions across North America, representing the vast majority of jurisdictions with ratepayer-funded energy efficiency programs.

The majority of jurisdictions with ratepayer funded energy efficiency programs conduct NTG research, though only half adjust gross savings based on research. While there appears to be a trend towards considering participant and non-participant spillover in NTG research in recent years, the majority of research only includes FR adjustments. Both FR and spillover are most commonly estimated through a self-report (participant survey) approach, though econometric methods (e.g., billing analysis) and market share modeling approaches are occasionally used.

Navigant also researched whether jurisdictions offer utility performance incentives for meeting their savings goals. U.S. states that provide a performance incentive mechanism for utilities or program administrators are more likely to make deemed or researched NTG adjustments.

Researched NTG Values in Selected Jurisdictions

Navigant reviewed a total of 19 documents that conducted NTG research of non-residential gas programs covering nine jurisdictions in North America, including: California, Colorado, Massachusetts, Minnesota, New Jersey, New Mexico, Oregon, Washington, and Wisconsin. Within these 19 documents, 38 distinct NTG values were reported.

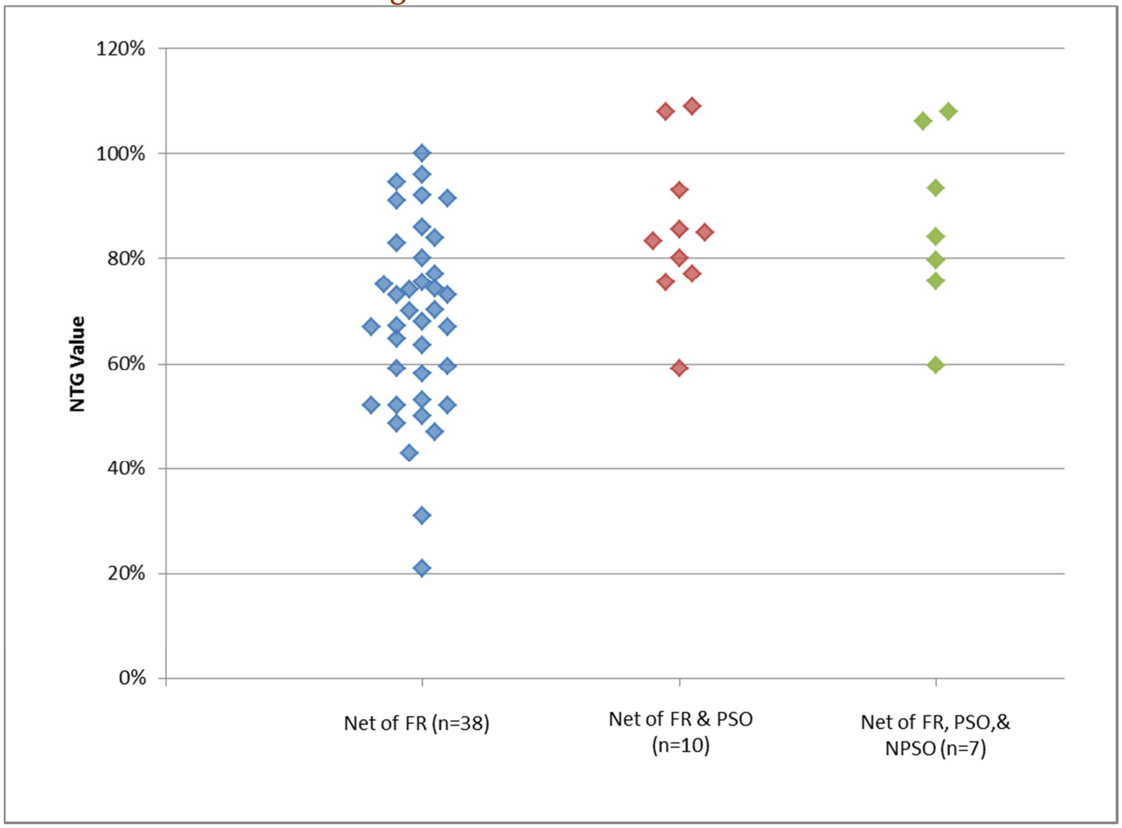
Different formulations of NTG values are presented, with each including or excluding different NTG factors. In particular, the following NTG values are presented:

- Net-of-free ridership = 1- FR,
- Net-of-free ridership and participant spillover = 1 – FR + PSO, and
- Net-of-free ridership and all spillover = 1- FR + PSO + NPSO
  (Note: NPSO is non-participant spillover)

This approach conveys information on NTG values based on the common definitions across the studies, and avoids inappropriate comparisons that could result from comparing the studies' reported NTG values when they include different components.

A review of researched net-of-free ridership values for non-residential gas programs exhibits a wide dispersion (21% to 100%) with a slight "clustering" of values between 40% and 90%, as shown in Figure ES-1. The average net-of-free ridership value is 68%. As expected, NTG values are larger when considering spillover. Average net-of-free ridership & PSO value is 86% and average net-of-free ridership & spillover value is 87%, suggesting that NPSO is small for non-residential gas programs.

Figure ES-1. NTG Values



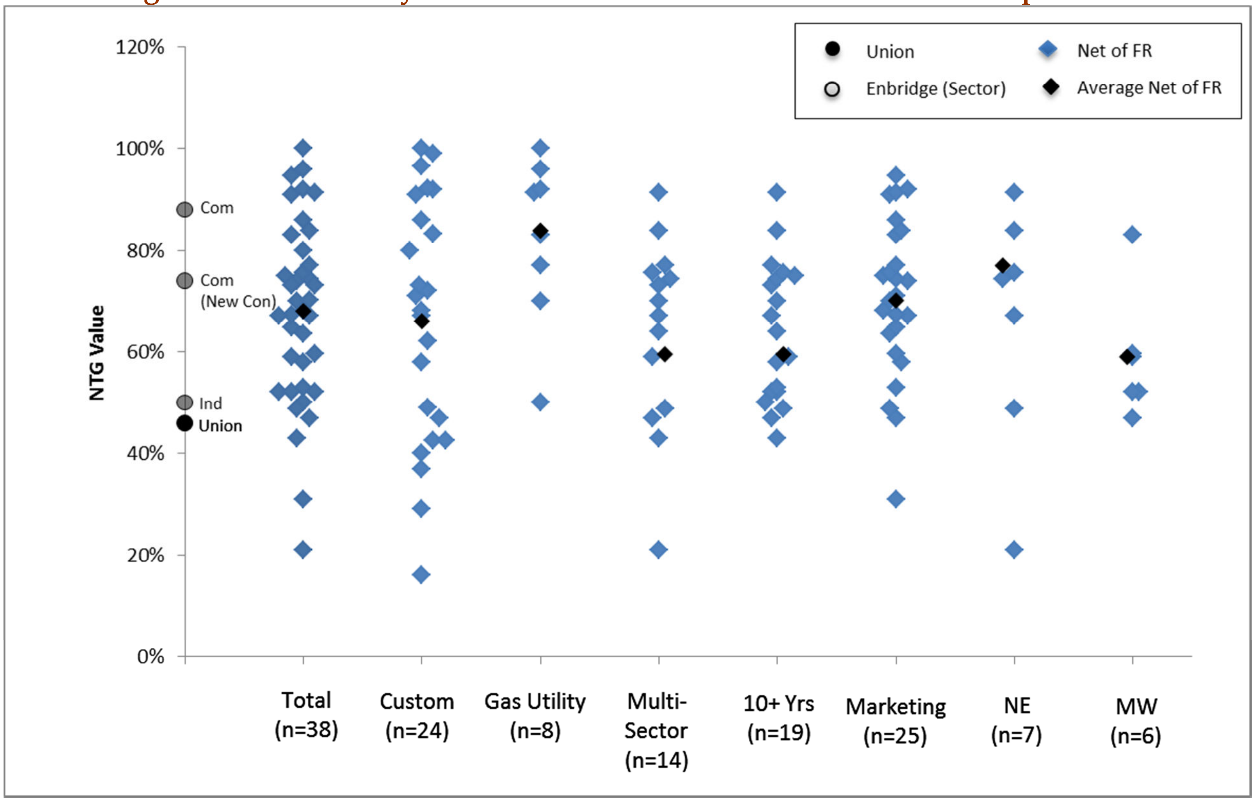
Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG values (program-utility-year combinations) reported in the 19 studies.

To provide additional context Navigant reviewed NTG values by study, program year and region and found that the variation in NTG values did not appear to be driven by the program evaluator, program year, or region. Navigant also examined whether variation in NTG values resulted from differences in the analytic rigor of the methodology (all used self-reports), using enhanced self-report methods in the form of trade ally feedback as a proxy. Free ridership values appeared lower with the inclusion of trade ally feedback. Finally, Navigant compared electric NTG values to gas NTG values for studies that reported both values and found that gas NTG values exhibited a wider dispersion.

Navigant also reviewed researched NTG values based on specific program characteristics: program type, customer segment, utility-type, program maturity, and program marketing strategy. Trends in NTG values are less defined and should be interpreted with caution due to the small sample sizes. Nevertheless, some trends emerged: NTG values for custom programs exhibited a wider dispersion than programs offer prescriptive incentives or both, programs offered by gas-only utilities appear to have lower FR than programs offered by combination utilities, and FR appears to be greater with program maturity.

Figure ES-2 presents the net-of-free ridership values for program characteristics that are most similar to Union and Enbridge's custom C&I programs. In addition, Union and Enbridge's current NTG values, based on the 2007-2008 research conducted by Navigant (formerly Summit Blue Consulting) are presented. Note that Union currently uses one NTG value for C&I custom programs while Enbridge uses sector-specific NTG values.

Figure ES-2. Summary of Relevant Researched Net-of-Free Ridership Values



Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG values (program-utility-year combinations).

Both Union and Enbridge's current NTG values are within the range of researched values. Union's NTG value is below the average value. Enbridge's NTG value for the commercial sector is above the average value while the NTG value for the industrial sector is below the average value.

Assessing Options for NTG

Gross savings can usually be estimated quite accurately, however, estimating net savings poses greater challenges. Given the uncertainty around any NTG value, Navigant applied a Decision Analysis approach for organizing information around alternative approaches to setting NTG values.

There are a number of benefits resulting from more precise NTG values, including the ability to improve program design and implementation, more accurate utility incentive payments, and the ability to consider energy savings as a resource. Navigant conducted a value of information

(VIF) analysis on the second benefit, incentive payments, as the benefit/cost of improved information can be easily quantified.

To support the VIF analysis, Union and Enbridge conducted a sensitivity analysis of utility incentive payments resulting from their custom programs, using a +/- 10 percentage point margin of error on the custom programs NTG values. This analysis revealed that improving the precision of custom NTG values has a sizable impact on incentive payments. Table ES-1 and Table ES-2 present a value of information analysis for Union and Enbridge respectively at targeted net savings.

Table ES-1. Value of Information Assessment for Union

	NTG Value for Custom Programs		Incentives	Change in Incentives
Base Case:	**Current NTG** NTG = 0.46	→	Incentives = $2.73 M	
Scenario 1:	**Higher True NTG** NTG = 0.56	→	Incentives = $5.63 M	**(+$2.90 M)**
Scenario 2:	**Lower True NTG** NTG = 0.36	→	Incentives = $0.8 M	**(-$1.93 M)**

Source: Sensitivity analysis provided by Union.

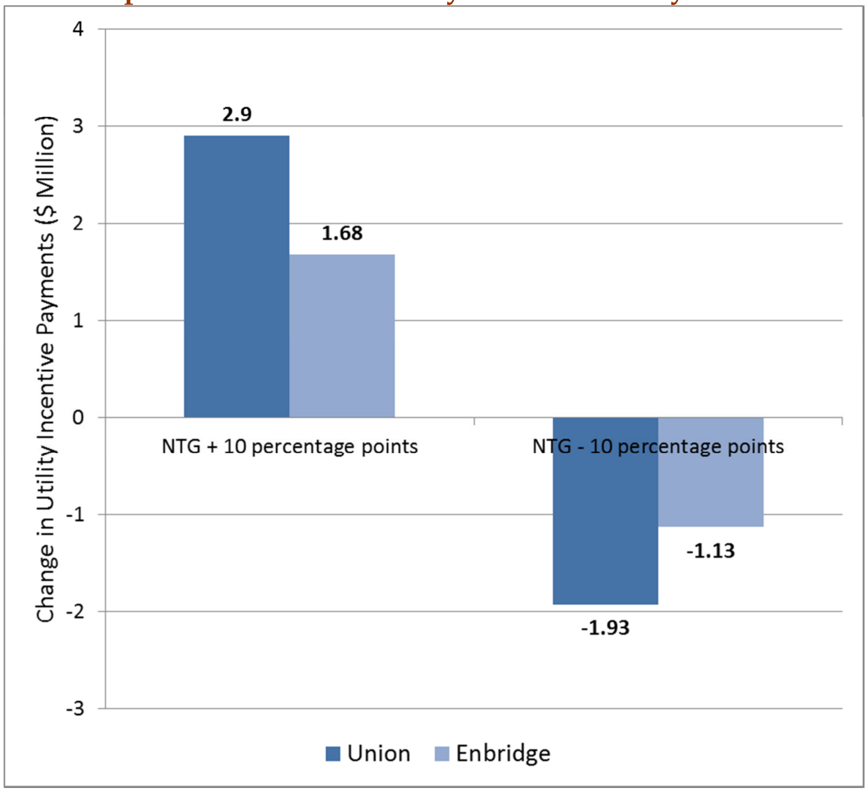
Table ES-2. Value of Information Assessment for Enbridge

	NTG Value for Custom Programs		Incentives	Change in Incentives
Base Case:	**Current NTG by Program** Commercial = 0.80 Commercial New Construction = 0.74 Industrial = 0.50	→	Incentives = $2.58 M	
Scenario 1:	**Higher True NTG** Commercial = 0.90 Commercial New Construction = 0.84 Industrial = 0.60	→	Incentives = $4.26 M	**(+$1.68 M)**
Scenario 2:	**Lower True NTG** Commercial = 0.70 Commercial New Construction = 0.64 Industrial = 0.40	→	Incentives = $1.45 M	**(-$1.13 M)**

Source: Sensitivity analysis provided by Enbridge.

The penalty for assuming a NTG value that is +/- 10 percentage points different from the actual NTG value is roughly $1 to $3 million in utility incentive payments, as shown in Figure ES-3. If the cost of revising the NTG values is less than $0.5 million then revising the values *could be judged to be warranted* assuming NTG research could reduce the margin of error by one-half (i.e., the range of the likely true NTG values).

Figure ES-3. Comparison of the Sensitivity of Incentive Payments to NTG Values



Source: Sensitivity analyses provided by Union and Enbridge.

Navigant provides a brief review of five general approaches to NTG, providing an estimate of the improved precision of the NTG value and the approximate cost per utility (Table ES-3). Alternate NTG approaches could improve the precision of NTG values by approximately 50% at an approximate cost of $0.25 - $0.50 million per utility.

Table ES-3. Ability of NTG Approaches to Produce More Precise NTG Values

General NTG Approach	Estimated Improved Precision (or Reduced Range) of NTG Value	Cost of NTG Approach per Utility (approximate)
Transfer NTG Values from Other Research	Little change	$3 – 5k
Adjust NTG Values based on Program Factors	Little change	$5 – 10k
Align NTG Values using Limited Primary Data	3 percentage points	$100 – 200k
Full NTG Research Study – After Program Year	5 percentage points	$250 – 500k
Integrated/Fast Feedback NTG Estimation	5 percentage points	$250 – 500k

Source: Navigant analysis.

NAVIGANT

1. Introduction

This report provides information to support the sub-committee of Ontario's TEC in its deliberations on the appropriate approach to NTG values in Ontario. Through a jurisdictional review of the approach to net savings, and a review of researched NTG values for programs comparable to Union and Enbridge custom C&I gas programs, Navigant provides an assessment of the various approaches to NTG.

1.1 Background

Union and Enbridge have delivered Demand Side Management (DSM) initiatives since 1997 and 1995, respectively, including programs that involve custom projects in the C&I sectors. Custom projects cover opportunities where savings are linked to unique end uses and technologies. The DSM portfolio for both utilities includes several hundred custom projects annually. Union and Enbridge DSM activities are regulated by the OEB.

In June, 2011, Union and Enbridge entered into a new DSM regulatory framework. In addition to filing comprehensive, multiyear program plans, Union and Enbridge established Terms of Reference (ToR) for engaging stakeholders. The ToR established engagement processes, and included the creation of a common TEC for both gas utilities. The goal of the TEC is to "establish DSM technical and evaluation standards for measuring the impact of natural gas DSM programs in Ontario."[1]

In 2007-2008, Navigant (formerly Summit Blue Consulting) conducted the first attribution study of Union and Enbridge's custom C&I programs to evaluate FR and spillover effects.[2] The OEB approved the FR adjustment, but did not approve the spillover factor. Since that time, there have been a host of program environment changes, including economic conditions, energy prices, advances in technology, as well as changes in the design and delivery of the custom programs. As a result, the TEC is prioritizing updates to FR and spillover adjustment factors as part of its mandate.

1.2 Report Objective

There are a range of options for addressing net savings that could be adopted for natural gas DSM programs in Ontario, from deeming a NTG value to conducting research to estimate a NTG value. The objective of this report is to provide information to assist the TEC sub-committee in their deliberations on appropriate approaches for developing an NTG value for these programs. This report is not meant to provide a specific recommendation, but rather to

---

[1] *2012 Custom Free Ridership and Participant Spillover Jurisdictional Review Request for Proposal*, Ontario Natural Gas Technical Evaluation Committee, October 29, 2012.

[2] *Source:* Summit Blue Consulting. 2008. *Custom Projects Attribution Study.* Union Gas Limited and Enbridge Gas Distribution, October 27, 2008.

provide information on the range of approaches to assist the TEC sub-committee in making their determination.

The steps taken to achieve this objective include the following:

- Understand the portfolio of Union and Enbridge's custom C&I gas programs (Section 3)
- Review the approach to net savings across a wide array of jurisdictions in the United States and Canada to identify trends in the regulatory and methodological approach to net savings (Section 4)
- Conduct a review of researched NTG values of non-residential gas programs in selected jurisdictions (Section 5)
- Conduct a decision analysis to assess the options for NTG (Section 0)

2. Methodology

This section describes the methodology Navigant employed to provide information to assist the TEC sub-committee in their deliberations on the appropriate approach to NTG for custom natural gas DSM programs in Ontario. The sub-sections that follow discuss the four distinct tasks conducted by Navigant:

- Reviews of the custom C&I natural gas programs,
- Summary of research methods and regulatory approaches to net savings,
- Review of researched NTG values in selected jurisdictions, and
- Assessing options for updating NTG values for these programs.

2.1 *Union and Enbridge Programs*

To develop an understanding of the portfolio of Union and Enbridge's custom C&I gas programs, Navigant conducted a review of the following:

- Description of programs included in the *2012 Custom Free Ridership and Participant Spillover Jurisdictional Review* request for proposal, and
- Union and Enbridge program websites.

Union and Enbridge also provided additional information on features of program design and implementation as requested by Navigant.

2.2 *Approach to Net Savings*

Navigant conducted research to provide a summary of the regulatory and methodological approach to net savings adopted by jurisdictions across North America, as well as whether jurisdictions offer utility performance incentives for meeting their savings goals. The research methodology included a review of:

- Utility websites,
- Regulatory agency websites,
- Websites of research/advocacy groups such as the Regulatory Assistance Project (RAP), American Council for an Energy-Efficiency Economy (ACEEE), Consortium for Energy Efficiency (CEE), and the Edison Foundation, and
- Studies that previously surveyed the approach to net savings.[3]

In total, Navigant reviewed the approach to net savings taken by 42 jurisdictions across North America, representing the vast majority of jurisdictions with ratepayer-funded energy efficiency programs. In addition, a review of the approach to net savings in nine selected jurisdictions is discussed in the following section.

[3] Refer to 7.Appendix A for a list of references for methodological resources.

2.3 *Researched NTG Values in Selected Jurisdictions*

To provide the TEC sub-committee with a comprehensive review of researched NTG values Navigant worked with the TEC sub-committee in an iterative process to identify relevant jurisdictions/ programs and accompanying evaluation studies. The research methodology included:

- Review of program evaluations conducted by Navigant and Summit Blue Consulting (acquired by Navigant in 2010),
- Review of program evaluations identified by Navigant staff,
- Review of the Northeast Energy Efficiency Partnerships' Repository of State and Topical EM&V Studies,
- Search of the California Measurement Advisory Council searchable database,
- Search of the Consortium for Energy Efficiency searchable database,
- Review of State and Utility websites for program evaluations and filings,
- General internet searches for program evaluations, and
- Outreach to industry professionals.

This list was revised to develop a shortlist of programs comparable to Union and Enbridge's programs, accounting for factors such as customer segment and program design. Additional studies were excluded due to the methodology employed and/or the applicability of the reported NTG values. [4]

NTG values for programs targeting natural gas savings is the focus of this report due to the greater than expected availability of gas utility studies, as well as combination utility studies where natural gas NTG values were reported separately.

A total of 19 documents[5] were selected covering nine jurisdictions in North America, including: California, Colorado, Massachusetts, Minnesota, New Jersey, New Mexico, Oregon, Washington, and Wisconsin. In some cases, one document reported NTG values for multiple programs, multiple utilities, or multiple program years. In total, 38 distinct NTG values were reported. Table 1 presents the number of distinct values reported across the 19 documents.

[4] Refer to Appendix B for an example of two notable studies/jurisdictions excluded from the analysis.
[5] Refer to Appendix C for an annotated bibliography of these documents.

Table 1. Documents Reviewed and Distinct NTG Values Reported

Document Number and Title	Number of Distinct Values Reported	Reason for Including Multiple Values
1. 2004/2005 Statewide Express Efficiency and Upstream HVAC Program Impact Evaluation	4	NTG values reported for 4 utilities: PG&E, SDG&E, SCE, and SCG.
2. 2004-2005 Statewide Nonresidential Standard Performance Contract Program Measurement and Evaluation Study	2	NTG values reported for 2 investor-owned utilities: PG&E and SDG&E.
3. 2006-2008 Retro-Commissioning Impact Evaluation	4	NTG values reported for 4 utilities: PG&E, SDG&E, SCE, and SCG.
4. 2011 Commercial and Industrial Natural Gas Programs Free-Ridership and Spillover Study	6	NTG values reported for 6 utilities: NSTAR, Unitil, New England Gas, National Grid, Columbia Gas, and Berkshire Gas.
5. Evaluation of 2011 DSM Portfolio	2	NTG values reported for 2 programs: Commercial Solutions and SCORE pilot.
6. Fast Feedback Results	3	NTG values reported for 3 programs: Existing Multifamily, Existing Buildings, and Industrial Production Efficiency.
7. Impact and Process Evaluation of the 2006-2007 Building Efficiency Program	2	NTG values reported for 2 program-years: 2006 and 2007.
8. Evaluation of Building Efficiency Program 2004 & 2005	2	NTG values reported for 2 program-years: 2004 and 2005.
9. Impact and Process Evaluation of the 2006-2007 New Building Efficiency Program	2	NTG values reported for 2 program-years: 2006 and 2007.
10. Focus on Energy Evaluation: Business Programs Impact Evaluation Report – Last Quarter of Calendar Year 2009 and First Two Quarters of Calendar Year 2010	2	NTG values reported for 2 program-years: 2009 and 2010.
11. 2006-2008 Evaluation Report for PG&E Fabrication, Process and Manufacturing Contract Group	1	N/A
12. Evaluation of the Southern California Gas Company 2004-2005 Non-Residential Financial Incentives Program	1	N/A
13. Comprehensive Process and Impact Evaluation of the Business Heating Efficiency Program - Colorado	1	N/A

Document Number and Title	Number of Distinct Values Reported	Reason for Including Multiple Values
14. New Jersey's Clean Energy Program Energy Impact Evaluation: SmartStart Program Impact Evaluation	1	N/A
15. Commercial and Industrial Energy Efficiency Retrofit Custom Programs Portfolio Evaluation	1	N/A
16. Focus on Energy Evaluation: Business Programs – Additional Looks at Attribution	1	N/A
17. Focus on Energy Evaluation: Semiannual Report (Second Half of 2009)	1	N/A
18. Focus on Energy Evaluation: Semiannual Report (First Half of 2009)	1	N/A
19. Achieving Natural Gas Savings Goals: Commercial Heating Programs Heat It Up	1	N/A
Total: 19 Documents Reviewed, 38 Distinct Values Reported		

Source: Navigant analysis.

Navigant reviewed these selected documents to summarize methods used to assess NTG values across these jurisdictions. The following estimates from these studies are reported:

- Net-of-free ridership = 1- FR,
- Net-of-free ridership and participant spillover = 1 – FR + PSO, and
- Net-of-free ridership and all spillover = 1- FR + PSO + NPSO
(Note: NPSO is non-participant spillover)

This approach conveys information on NTG values based on the common definitions across these studies, and avoids inappropriate comparisons that could result from comparing the studies' reported NTG values when they include different components. Table 2 presents the distribution of the different NTG factors reported across the 38 distinct values.

Table 2. NTG Values Reported

	NTG Values Reported by Adjustment Factor Included	Net-of-NTG Factors
FR	28	38
FR & PSO	3	10
FR, PSO & NPSO	7	7

Source: Navigant analysis.

A total of 28 NTG values reported adjust for FR only, 3 adjust for FR and PSO, and 7 adjust for FR, PSO, and NPSO. The last column shows the information gained from presenting net-of-NTG component values. For example, all 38 of the NTG values reported include values for FR.

Rather than just present the NTG values that adjust for FR only (n=28), the net-of-NTG component values are presented. In this case, (1 – FR) (n=38).[6]

In addition to these studies, Navigant also reviewed the 2008 evaluation of Union and Enbridge's custom projects program conducted by Summit Blue Consulting.[7]

2.4 Assessing Options for NTG

Given the uncertainty around NTG values, Navigant applied Decision Analysis methods to illustrate the risks faced by utilities and ratepayers when NTG values are uncertain and provide information on the benefits and costs of choosing one approach to net savings over another.

Navigant took the following steps to conduct the Decision Analysis:

1. Define the benefits of accurate (and costs of inaccurate) NTG values in a general context.
2. Narrow the focus the analysis on the benefits/costs for which Navigant had access to data; specifically, the incentives paid to utilities based on the estimated net savings (m^3) achieved by custom programs.
3. Establish a baseline against which a sensitivity analysis can be conducted where a selected NTG value is assumed to be correct, but in fact is incorrect by some margin of error.[8] The sensitivity analyses were conducted independently by Union and Enbridge and were not verified by Navigant.
4. Conduct a "value of information" analysis by examining the change in incentive payments resulting from better information on NTG values compared to the cost of obtaining the information (e.g., through NTG research).

In addition, Navigant organized the results of the Decision Analysis to provide insight into the tradeoffs from using different approaches to setting an NTG value, ranging from transferring values based on the jurisdictional review to conducting NTG research.

The next section (Section 3) presents an overview of the Union and Enbridge C&I programs to provide context. Following this program overview, Section 4 discusses the regulatory approach and methodological approach to NTG used by different jurisdictions followed by a review of researched NTG values in selected jurisdictions (Section 5). Finally, Section 0 presents the decision analysis for assessing alternate approaches to NTG.

---

[6] Because the documents reviewed contain varying degrees of detail and explanation, the Navigant team applied its best interpretation of these documents to synthesize the available information in a consistent manner.

[7] Summit Blue Consulting. 2008. *Custom Projects Attribution Study.* Union Gas Limited and Enbridge Gas Distribution, October 27, 2008.

[8] These first three steps are part of a "loss function" analysis which identifies the costs of selecting one NTG value when another value is the actual value.

3. Overview of Union and Enbridge Custom Programs

Union and Enbridge have been delivering natural gas DSM programs for over 10 years, including custom programs for the C&I sectors. This section provides an overview of these programs.

3.1 Union Custom Programs

Union offers the Custom Savings Program to C&I customers. Within the custom program umbrella there are numerous program offerings providing a combination of technical assistance and financial incentives:

- **Engineering Feasibility Study.** These comprehensive engineering analyses and assessments include both whole facility and end-use focused studies. Example projects include thermal surveys, HVAC audits, energy audits, and energy benchmarking.
- **Steam Trap Survey.** These studies focus exclusively on the use and efficiency of steam traps, and seek efficiencies in the discharge of condensation, air, and other non-condensable gases without losing steam.
- **Process Improvement Study.** This offering targets industrial facilities through comprehensive process improvement studies conducted by industry-specific production and energy utilization experts. Example projects include steam plant audits, process integration analyses, heating integration studies, and process operation improvement studies.
- **Integrated Energy Management Systems.** This program offering provides technical assistance and financial incentives to industrial customers for the installation of an integrated management system.
- **Customer Education.** This program provides education, training, and technical assistance to C&I customers.
- **New Equipment.** Technical assistance and financial incentives are provided to C&I customers to support the installation of new energy efficient equipment and processes. Examples of measures include furnaces, HVAC, heat recovery, controls, insulation, and building envelope.
- **Runsmart Building Optimization.** Technical assistance and financial incentives are provided to commercial customers (e.g., education, healthcare, offices, multi-unit residential, and entertainment) for building optimization. Examples of projects include verifying dampers and valves on air handling units, calibrating sensors and instrumentation, and insulation.

- **Operation and Maintenance.** This program offering provides technical assistance and financial incentives to C&I customers for operation and maintenance of existing measures. Typical projects include repairs to HVAC systems, hot water systems, insulation repairs, and steam system repairs.
- **Boiler Tune-Up.** Technical assistance and financial incentives are provided to industrial customers for a boiler tune-up. Boilers must have output of less than 25,000 pounds per hour or 800 BHP.
- **Meters.** Technical assistance and financial incentives are provided to industrial customers for the installation of natural gas, steam, or hot-water meters.
- **Infrared Anti-Condensate Plastic.** This program offering provides technical assistance and financial incentives to industrial customers for the installation of infrared anti-condensate plastic for a greenhouse.
- **Demonstration of New Technologies.** Technical assistance and financial incentives are provided to C&I customers for adopting new technologies that save natural gas.

3.2 Enbridge Custom Programs

Enbridge offers two custom C&I programs:

- **Commercial Custom Savings Program** provides both technical assistance and financial incentives to medium to large-sized new and existing commercial customers for energy efficient custom gas projects. Examples of custom measures include boilers, building automation systems, variable frequency drives, and demand control ventilation.
  1. The *Existing Buildings* program offering primarily focuses on projects with multiple technologies and requires technical assistance throughout the development of the project.
  2. Two new initiatives, launched in 2012, (*Energy Compass and Run It Right*) encourage a continuous improvement strategy for large commercial customers. These program offerings provide technical assistance by offering an energy efficiency diagnostic service and assisting with the implementation of low and no-cost operational improvements.
- **Industrial Continuous Energy Improvement Program** aims to reduce the natural gas use of medium to large-sized industrial customers through a continuous improvement approach. This approach includes five steps, providing both technical assistance and financial incentives for the implementation of energy efficiency projects:
  1. *Knowledge Development* involves educating customers through workshops and publications.
  2. *Opportunity Identification* involves providing technical assistance to customers in identifying energy efficiency opportunities.

3. *Measurement* provides technical assistance to identify and measure the information needed to make a decision regarding energy efficiency opportunities. Financial incentives are available for measurement equipment.
4. *Engineering Analysis* provides technical assistance to customers in quantifying the benefits and costs associated with an energy efficiency opportunity. Financial incentives are available if a third party consultation is required.
5. *Action and Implementation* provides technical assistance and financial incentives for energy efficiency projects.

Examples of projects include industrial process heat systems, steam systems, and heating and ventilation.

4. Approach to Net Savings

This section presents the findings from the jurisdictional review of the approach taken to net savings, as well as the availability of performance incentives. This section begins with a review of 42 jurisdictions in the United States and Canada, representing the vast majority of jurisdictions with ratepayer-funded energy efficiency programs. This is followed by a closer look at the nine jurisdictions selected for further review. The final section summarizes the findings that are most relevant to Union and Enbridge.

4.1 *Jurisdictional Review*

Table 3 presents a summary of the approach to net savings used in the 42 jurisdictions, including the treatment of a FR adjustment and whether spillover is considered.[9] The table also presents information on whether jurisdictions offer utility performance incentives for meeting their savings goals, though, as indicated below, these goals are linked to either *gross* or *net savings*. Following is a summary of key findings:

- One-third (33%) of the jurisdictions reviewed **do not adjust gross savings** for either FR or spillover; however, some of those states may conduct some NTG research to inform future program design. Half of the U.S. states that do not adjust gross savings provide performance incentives for utilities to achieve energy efficiency program goals or have a performance incentive pending.

- Relatively few (14%) of the jurisdictions reviewed use a **deemed approach** to NTG; the deemed NTG values may be determined at a portfolio level (ranging from 0.7 to 0.9) or on a measure-by-measure basis (as in California, Vermont, and Nevada). These deemed NTG values are typically developed after NTG research has been conducted through program impact evaluations, and are revised on a regular basis through negotiations between utilities and regulators (often informed by additional NTG research). Over three-quarters (83%) of the U.S. states that use a deemed NTG approach provide performance incentives for utilities to achieve energy efficiency program goals.

- Nearly half of all jurisdictions reviewed take a **research-based approach** to NTG analysis. The vast majority of those jurisdictions consider spillover in some capacity, at least for some program types, though spillover is still quantified much less often than FR. Both FR and spillover are most commonly estimated through a self-report (participant survey) approach, though econometric methods (e.g., billing analysis) and market share modeling approaches are occasionally used. Nearly three-quarters of the U.S. states that take a research-based NTG approach provide performance incentives for

[9] Note that within a given jurisdiction, the treatment of spillover may vary by program type (including whether participant, non-participant, or both types of spillover is researched), and evaluators may investigate the possibility of spillover but find that no spillover is occurring or that it cannot be quantified with enough precision to obtain regulatory approval. Thus, this column reflects jurisdictions which consider the possibility of spillover but have not necessarily quantified and received regulatory approval for spillover savings estimates.

utilities to achieve energy efficiency program goals or have a performance incentive pending.

Table 3. NTG Approaches, Treatment of Free Ridership and Spillover, and Availability of Performance Incentives by Jurisdiction

Jurisdiction	NTG Approach*	Free-Ridership Adjustment	Spillover Considered?	Performance Incentives?	Notes
Hawaii	Deemed (0.7)			Yes	
Arkansas	Deemed (0.8)			Yes	
Michigan	Deemed (0.9)			Yes	Some NTG research conducted but not currently required by regulators.
California	Deemed (varies by measure, 0.5 for custom gas measures)			Yes	Research conducted to inform deemed NTG values.
Nevada	Deemed (varies by measure)				Some NTG research conducted.
Vermont	Deemed (varies by measure)			Yes	
British Columbia	Researched	Yes	Yes		Deemed NTG of 1.0 used until researched.
Nova Scotia	Researched	Yes	Yes		
Colorado	Researched	Yes	Yes	Yes	
Connecticut	Researched	Yes	Yes	Yes	Gross savings are used to evaluate whether goals have been met.
Florida	Researched	Yes	Yes	Pending	
Georgia	Researched	Yes	Yes	Yes	
Illinois	Researched	Yes	Yes		
Indiana	Researched	Yes	Yes	Yes	
Kansas	Researched	Yes		Pending	
Maine	Researched	Yes	Yes		
Massachusetts	Researched	Yes	Yes	Yes	
Missouri	Researched	Yes	Yes	Pending	
New Hampshire	Researched		Yes	Yes	
New Mexico	Researched	Yes		Yes	

Jurisdiction	NTG Approach*	Free-Ridership Adjustment	Spillover Considered?	Performance Incentives?	Notes
New York	Researched	Yes	Yes	Yes	Deemed NTG of 0.9 used for programs without recent evaluations.
Oregon	Researched	Yes	Yes		
Pennsylvania	Researched	Yes	Yes		Gross savings are used to evaluate whether goals have been met.
Rhode Island	Researched		Yes	Yes	
Utah	Researched	Yes	Yes	Pending	
Wisconsin	Researched	Yes	Yes	Yes	
Wyoming	Researched	Yes	Yes		
Arizona	No NTG adjustment			Yes	
Delaware	No NTG adjustment				
District of Columbia	No NTG adjustment				
Idaho	No NTG adjustment			Pending	Some NTG research conducted but not required by regulators.
Iowa	No NTG adjustment				
Kentucky	No NTG adjustment			Yes	
Maryland	No NTG adjustment				
Minnesota	No NTG adjustment			Yes	
Nebraska	No NTG adjustment				
New Jersey	No NTG adjustment				
North Carolina	No NTG adjustment			Yes	
Ohio	No NTG adjustment			Yes	
Texas	No NTG adjustment			Yes	

Jurisdiction	NTG Approach*	Free-Ridership Adjustment	Spillover Considered?	Performance Incentives?	Notes
Washington	No NTG adjustment				Some NTG research conducted but not required by regulators.
South Dakota	Varies by utility	Yes	Yes		

* Deemed NTG values are pre-determined values typically developed after NTG research has been conducted through program impact evaluations. Researched NG values are most commonly estimated through a self-report (participant survey) approach, though econometric methods (e.g., billing analysis) and market share modeling approaches are occasionally used. *Source:* Navigant analysis of various resources including utility websites, regulatory agency websites, websites of research/advocacy groups, and studies that previously surveyed the approach to net savings (Appendix A).

4.2 *Selected Jurisdictions*

As noted in the Methodology section, Navigant reviewed a total of 19 documents that researched NTG. These documents represent nine jurisdictions, including: California, Colorado, Massachusetts, Minnesota, New Jersey, New Mexico, Oregon, Washington, and Wisconsin.

While documents that research NTG were identified, the approach to net savings in these selected jurisdictions varies as shown in Table 4. Most notably, three of the jurisdictions make no NTG adjustment and one jurisdiction deems NTG even though NTG research is being conducted. Also note that three of the nine jurisdictions do not have performance incentives.

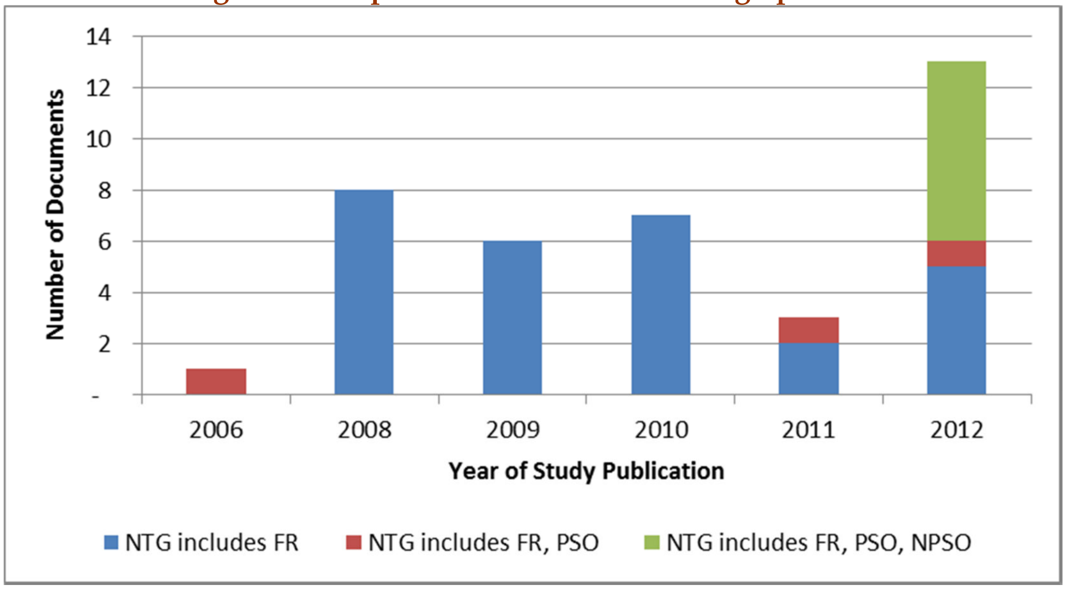
Table 4 . Approach to Net Savings in Selected Jurisdictions

Deemed	Researched Adjusts for Free Ridership and Spillover is Considered	No NTG Adjustment
California (0.5 for custom gas measures)	Colorado, Massachusetts, New Mexico (FR only), *Oregon*, and Wisconsin	Minnesota, *New Jersey*, and *Washington*

**Italics* indicate that the jurisdiction does not have performance incentives. *Source:* Navigant analysis.

Regional or temporal trends in whether participant and NPSO were also considered. Figure 1 presents the number of studies that include free-ridership, PSO, and NPSO by the year of study publication. Based on the sample of studies conducted in the selected jurisdictions, there is a clear trend towards including participant and NPSO in calculating NTG in recent years.

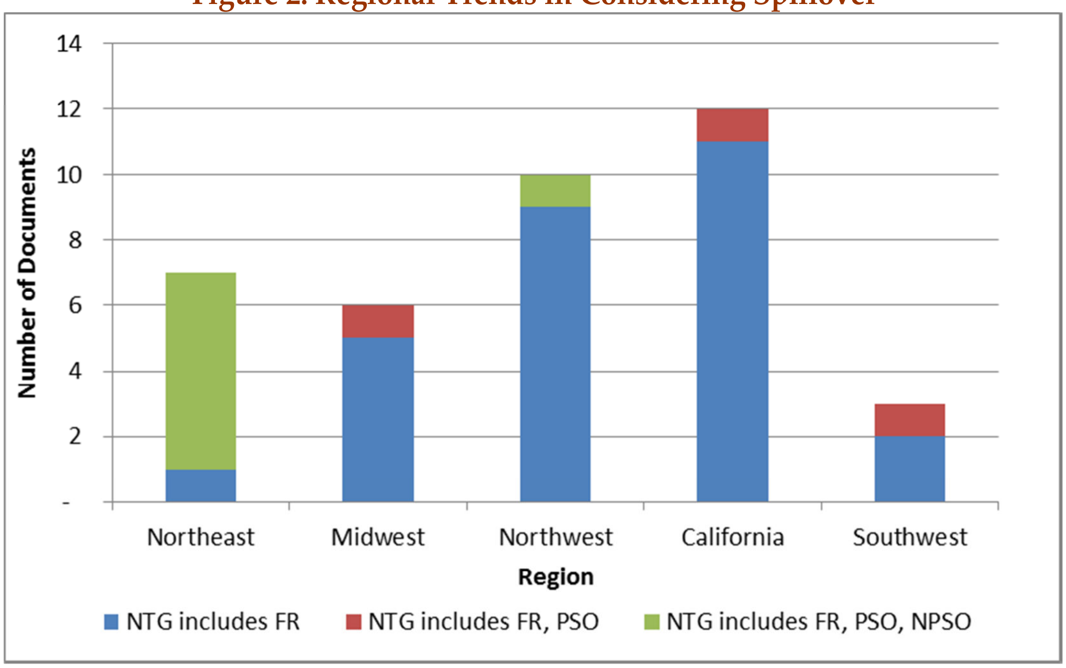
Figure 1. Temporal Trends in Considering Spillover



Source: Navigant analysis.

Figure 2 presents the number of studies that include free-ridership, PSO, and NPSO by region of the United States. Based on the sample of studies conducted in the selected jurisdictions, it appears that all regions consider PSO in calculating NTG values.

Figure 2. Regional Trends in Considering Spillover



Source: Navigant analysis.

4.3 *Application to Union and Enbridge*

Based on the jurisdictional review nearly half of the jurisdictions with rate-payer funded energy efficiency program conduct NTG research. Among the 33% that do not adjust gross savings some research is being conducted. For example, three of the nine jurisdictions selected for further review do not adjust gross savings while another one deems – yet NTG research is being conducted.

Trends in the included NTG factors are also identified. Among the nine selected jurisdictions there is a clear trend towards including both participant and NPSO in recent years, and that it is not a regional phenomenon. The next section of this report summarizes the researched NTG values resulting from the review of research conducted in the nine selected jurisdictions.

5. Researched NTG Values in Selected Jurisdictions

In this section Navigant summarizes the 38 NTG values reviewed in the nine selected jurisdictions. As described in Section 2.3, the NTG values presented are net-of-NTG factors. All values represent gas values, unless specified otherwise.

A summary of the studies' findings across the following categories are presented:

> ***Definitions***
>
> NTG values presented in this section represent "Net-of-NTG Factors."
>
> - NTG value including free ridership, NTG = (1-FR),
> - NTG value including free ridership and participant spillover, NTG = (1-FR+PSO), or
> - NTG value including free ridership and spillover, NTG = (1-FR+PSO+NSPO), where NPSO represents non-participant spillover.

- First, a high level summary of the NTG values for non-residential natural gas programs is provided. To provide context for these values we examine how these values vary with the document number, region, program year, and the analytic rigor of the methodology used. We also provide a comparison of the natural gas NTG values to the electric NTG values reported in the same documents.
- Next, the NTG values based on a variety of program characteristics, including program type, customer segment, utility-type, region, approach to program marketing, and program maturity are summarized.[10]
- The final section summarizes the findings that are most relevant to Union and Enbridge.

It is important to keep in mind that the NTG values presented in this section are the result of research conducted for different programs, in different program environments, and using different methodologies. As a result, interpretation of trends should be made with caution - differences in NTG values may reflect true differences in FR and spillover, or may simply reflect differences in evaluation methodologies, even among similar programs (Saxonis 2007).

5.1 Summary of NTG Values

Figure 3 summarizes net of NTG component values.[11] Some key patterns are evident in this Figure:

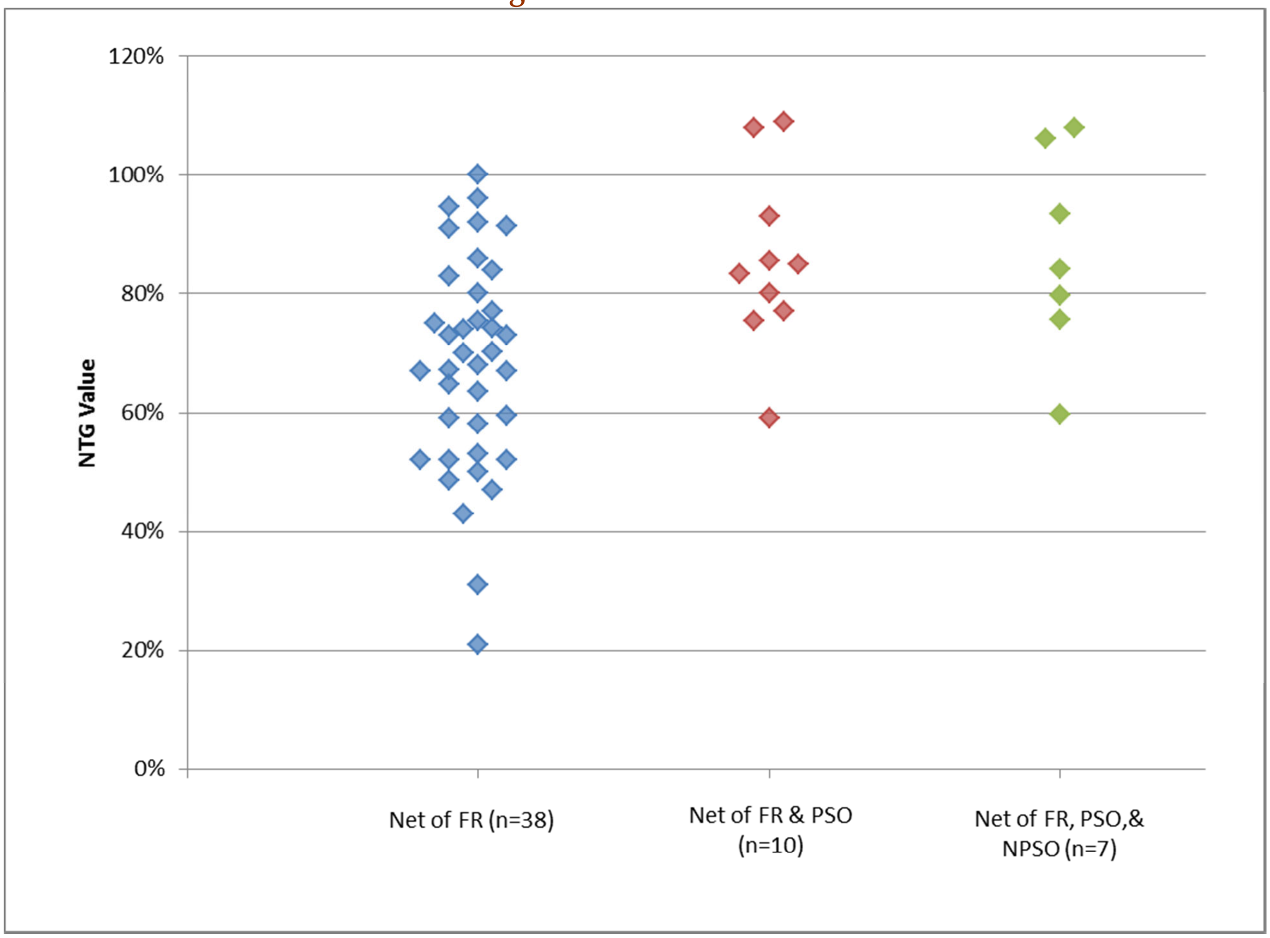
---

[10] Summarizing NTG values by various categories limits the sample sizes. As a result, caution should be used in interpreting NTG values.

[11] By presenting net-of-NTG component values, a distinct result reported in a document may be represented by multiple data points in the figures below. For example, if free ridership, PSO, and NPSO are considered, three data points will appear in the figure: the net-of-FR value, the net-of-FR & PSO value, and the net-of-FR, PSO & NPSO value.

- While the dispersion of net-of-free ridership values is quite large, ranging from 21% to 100%, the majority of values appear to "cluster" between 40% and 90%.
- There are only a few studies at the extremes of the range of net-of-free ridership values. One result reports high levels of free-ridership (79%) with another reporting zero free-ridership.[12]
- The average net-of-free ridership value is 68%.
- As expected, NTG values are larger when considering spillover. Average net-of-free ridership & PSO value is 86% and average net-of-free ridership & spillover value is 87%, suggesting that NPSO is small for non-residential gas programs.[13]

Figure 3. NTG Values



Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG values (program-utility-year combinations) reported in the 19 studies.

---

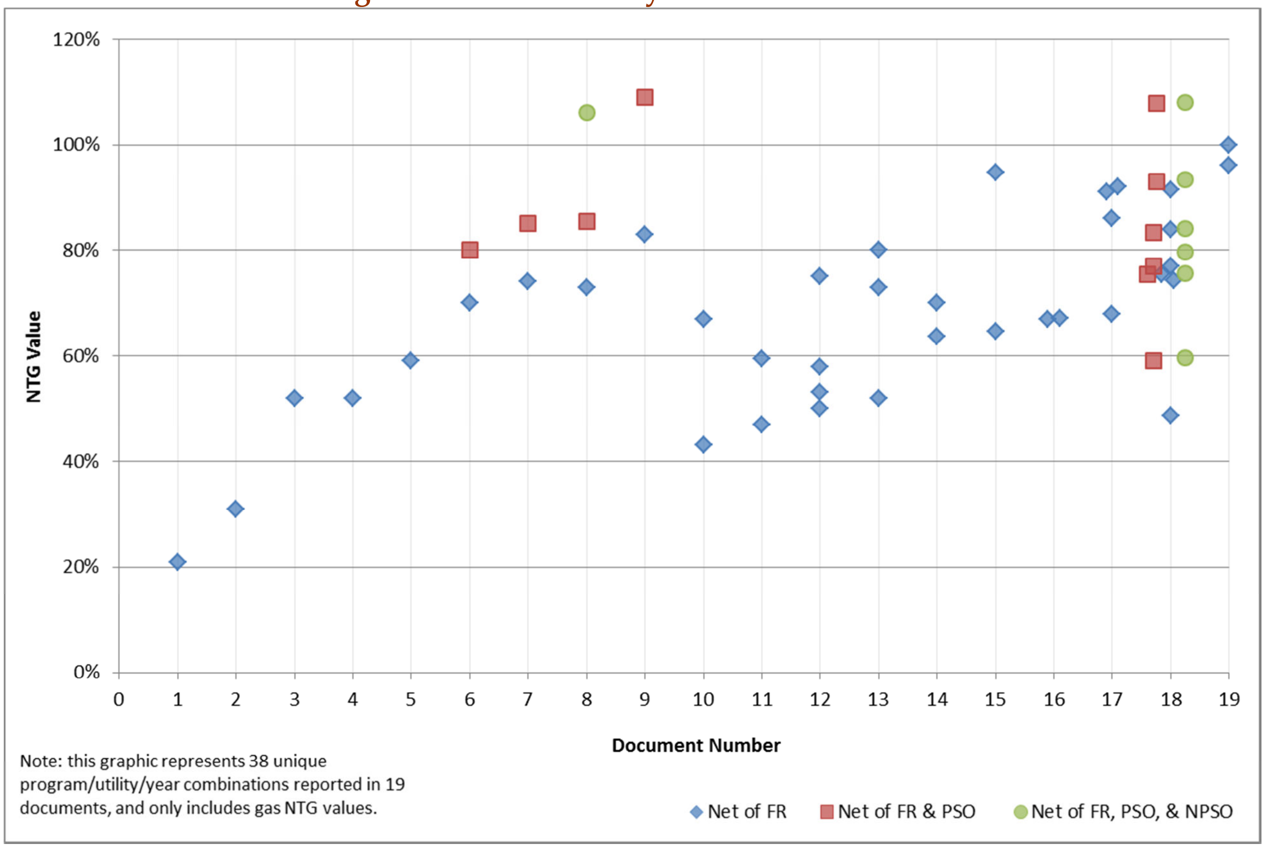
[12] Zero free-ridership was reported for a small pilot program (n=30) offering custom and prescriptive incentives targeted at K-12 school districts. 79% free-ridership was reported for a retrofit program in its third program year. The sample size (n=18) represents 75% of participants with natural gas measures and 10% of total program participants. Both studies relied on self-report methods.

[13] 5 of the 7 data points for NPSO report values of less than 1% with another reporting 2.6% (all values reported by the same study). The remaining data point reports NPSO of 21% with a corresponding PSO value of 13%).

To further examine trends in NTG values, Figure 4 summarizes the distinct NTG values reported by each document. There are two key findings:

- Only two documents report net-of-FR values below 40%.
- Net-of-FR values that exceed 90% are reported by just four documents and generally exhibit a clustering of multiple values. For example, document number 19 reports two distinct NTG values, both of which are larger than 90%.

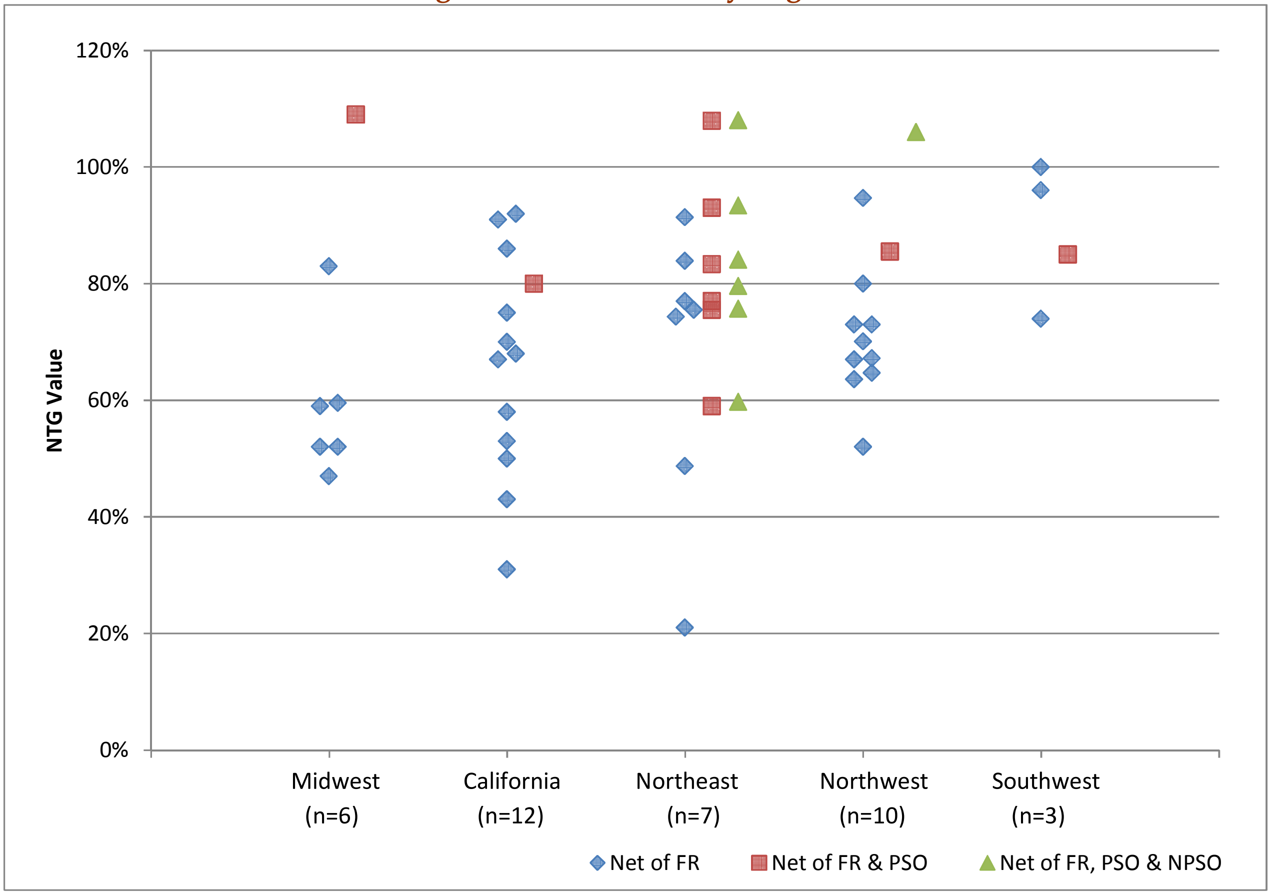
Figure 4. NTG Values by Document Number



Source: Navigant analysis.

Figure 5 summarizes NTG values by region. No clear regional trends emerge except it appears there is a clustering of net-of-FR values in the Northwest around 70%. These values represent evaluations of multiple program-years of two programs, with evaluations conducted by multiple evaluators.

Figure 5. NTG Values by Region

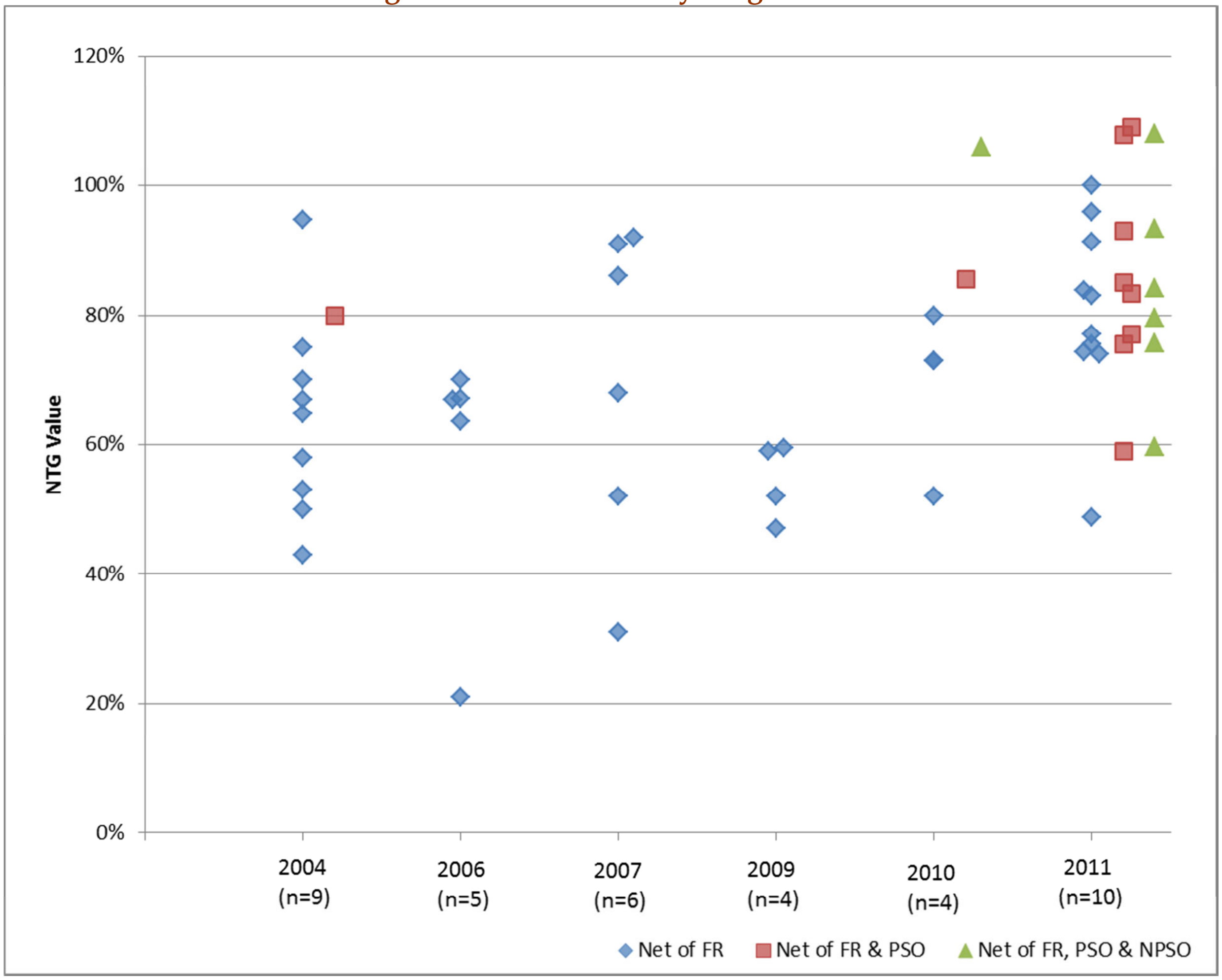


Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) in each region; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable).

Economic conditions may influence NTG values though few longitudinal studies have been conducted to reveal with certainty how FR and spillover are influenced. Saxonis (2007) identifies research conducted in the 1990's that suggest FR is lower during economic downturns. To ensure that trends in NTG values are not driven by specific economic conditions, Navigant explored whether NTG values vary by program year in Figure 6.[14] While there is a slight upward trend in the net-of-FR estimates, it is not large enough to cause concern about using average values if the TEC decides to do so.

[14] When two program years were evaluated, the first program year is used. For example, if a study evaluates program years 2004-2005, the NTG value is recorded for 2004.When three program years were evaluated, the middle program year is used. For example, if a study evaluates program years 2006-2008, the NTG value is recorded for 2007.

Figure 6 . NTG Values by Program Year



Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) by program year; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable).

To provide further context to this summary of NTG values Navigant explored whether there are trends in NTG values based on the analytic rigor of the methodology, but were limited in our efforts due to a lack of data. For example, the sample size for most of the results was identified, but the documents did not report population size or the fraction of energy savings that the sample size represents. Without context for the sample size, information on how NTG values vary with sample size provides little insight.[15]

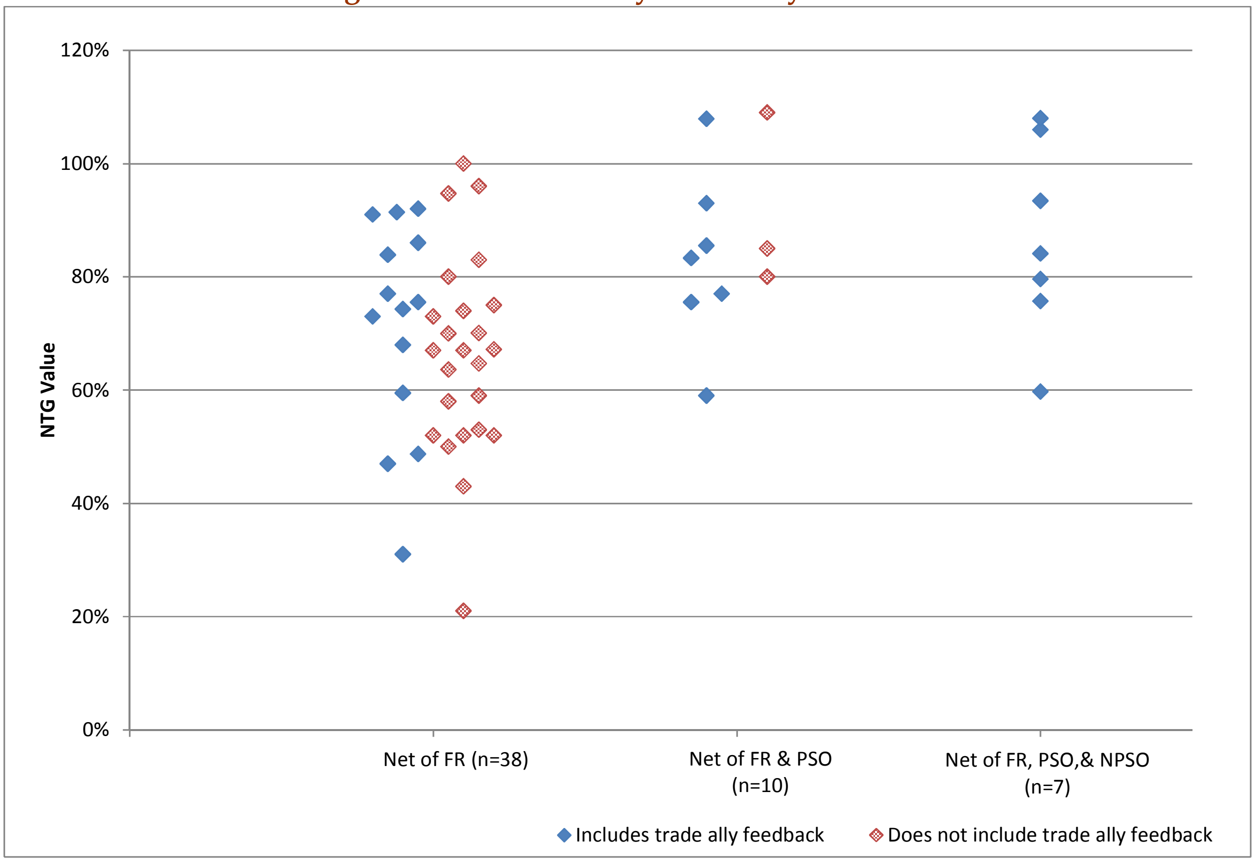
Instead, Navigant uses a proxy for the analytic rigor of the methodology based on data that is available, namely, whether the evaluators used enhanced self-report methods in the form of trade ally feedback. Figure 7 summarizes NTG values differentiating between whether trade ally feedback was incorporated in the NTG calculation. Net-of-free ridership values appear to

---

[15] Refer to Appendix D for information on sample size.

cluster at slightly larger values when incorporating trade ally feedback. This is not unexpected as trade ally feedback often decreases FR because trade allies have more insight about the full extent of the program's influence on the market.

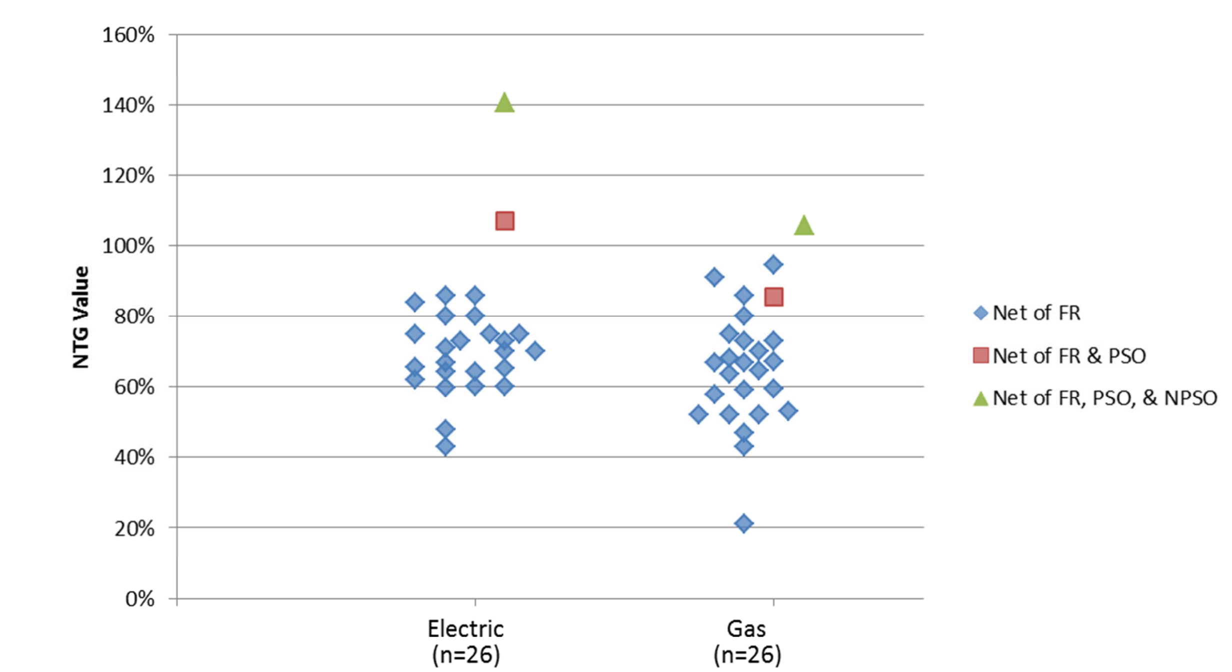
Figure 7. NTG Values by Trade Ally Feedback



Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG values (program-utility-year combinations) reported in the 19 studies.

Comparing gas NTG values to electric NTG values may also provide additional insight. Many of the documents reviewed target both electric and gas measures, but report NTG values for electric and gas measures separately. Figure 8 compares electric NTG values to gas NTG values for those documents that report both electric and gas NTG values. Net of FR values appear to cluster for both gas and electric, but the clustering of gas values is slightly wider than electric. Average net-of-free ridership values are similar, 69% for electric and 65% for gas.

Figure 8. Electric versus Gas NTG Values



Note: only documents with both electric and gas NTG values are included in this graphic.

Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) for each fuel type; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable).

The following section examines whether NTG values vary by features of program design and delivery.

5.2 *Summary Based on Program Characteristics*

In this section, Navigant summarizes NTG values based on various characteristics of program design and delivery. In particular, variation in NTG values is examined based on:[16]

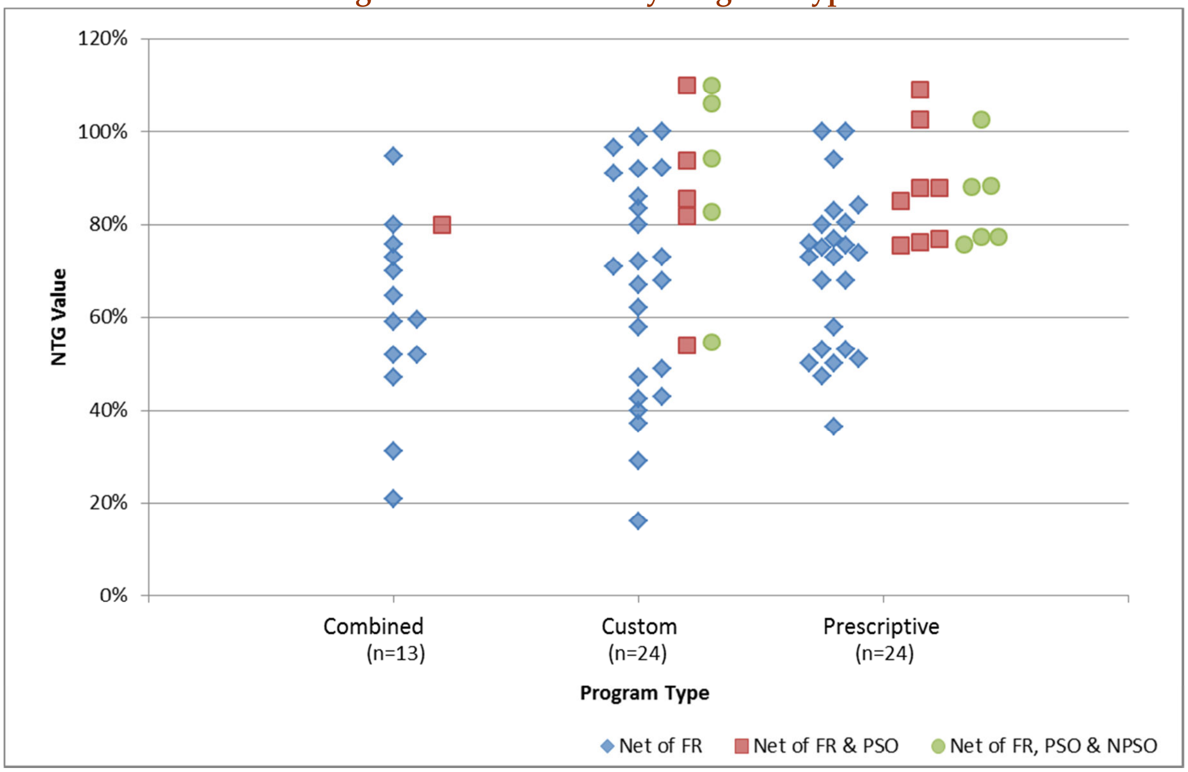
1. **Program-type**, differentiating between custom, prescriptive, and both.
2. **Customer segment**, differentiating between commercial, industrial, agricultural, institutional, and multi-sector.
3. **Utility-type,** differentiating between utilities/organizations that offer electric and gas versus those that offer gas-only.
4. **Program maturity,** differentiating by the number of years since program inception.

[16] Navigant explored other characteristics of program design, such as incentives as a percent of incremental cost, extent of design assistance throughout the program, program objectives, and more, however, because most studies did not provide this level of detail on the programs they were not included in the analysis.

5. **Program marketing strategy**, differentiating between a direct marketing/outreach, channel/partners, and both.

Figure 9 summarizes NTG values by program type (custom, prescriptive, or both).[17] Custom net-of-FR values exhibit a wider dispersion relative to prescriptive values. Excluding some outlier custom values, the ranges are fairly similar but the prescriptive values exhibit more clustering between 50% and 85%, whereas custom values do not appear to cluster in any particular range of values.

Figure 9. NTG Values by Program Type



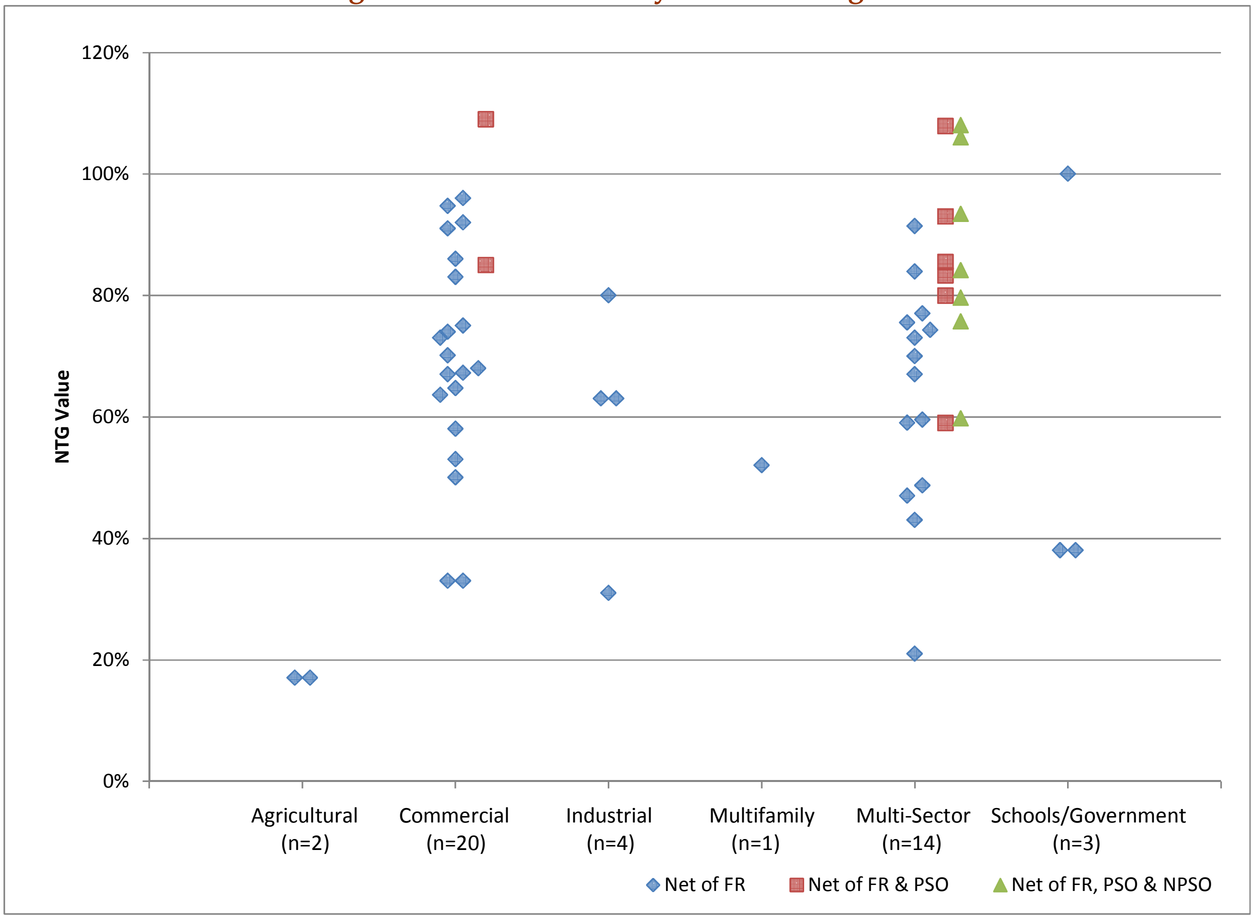
Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) for each program type; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable).

Figure 10 summarizes NTG values by customer segment.[18] Most of the programs included in this review are targeted at the commercial sector or are classified as multi-sector programs. While there is a wide dispersion of NTG values, the majority of values are found within the 60% and 80% range.

[17] In an effort to identify whether there are trends in NTG values by program type, when a NTG value was disaggregated into custom and prescriptive categories, these NTG values were included separately, resulting in a total of 61 data points for this analysis.

[18] In an effort to identify whether there are trends in NTG values by customer segment, when a NTG value was disaggregated into customer segments, these NTG values were included separately, resulting in a total of 44 data points for this analysis.

Figure 10. NTG Values by Customer Segment

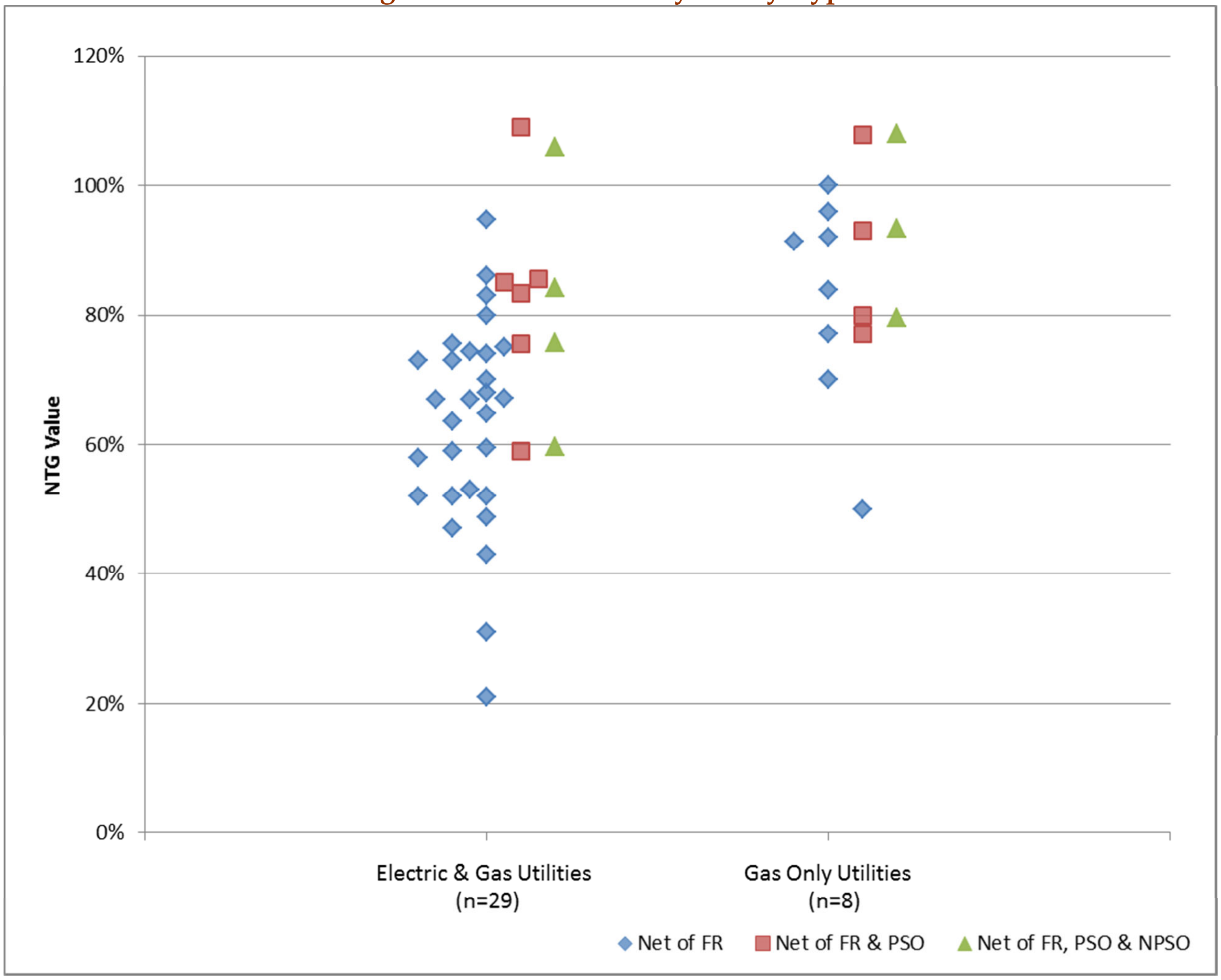


Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) for each segment; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable).

Figure 11 summarizes NTG values by utility-type (e.g., gas only, electric and gas).[19] Of the documents reviewed, more programs are offered by electric and gas utilities relative to gas-only. With only a few distinct net-of-FR values for gas-only utilities, comparisons across utility-types should be made with caution. Nevertheless, there appears to be a trend of lower FR and higher NTG values for programs offered by gas-only utilities.

[19] Note that the values presented are gas NTG values.

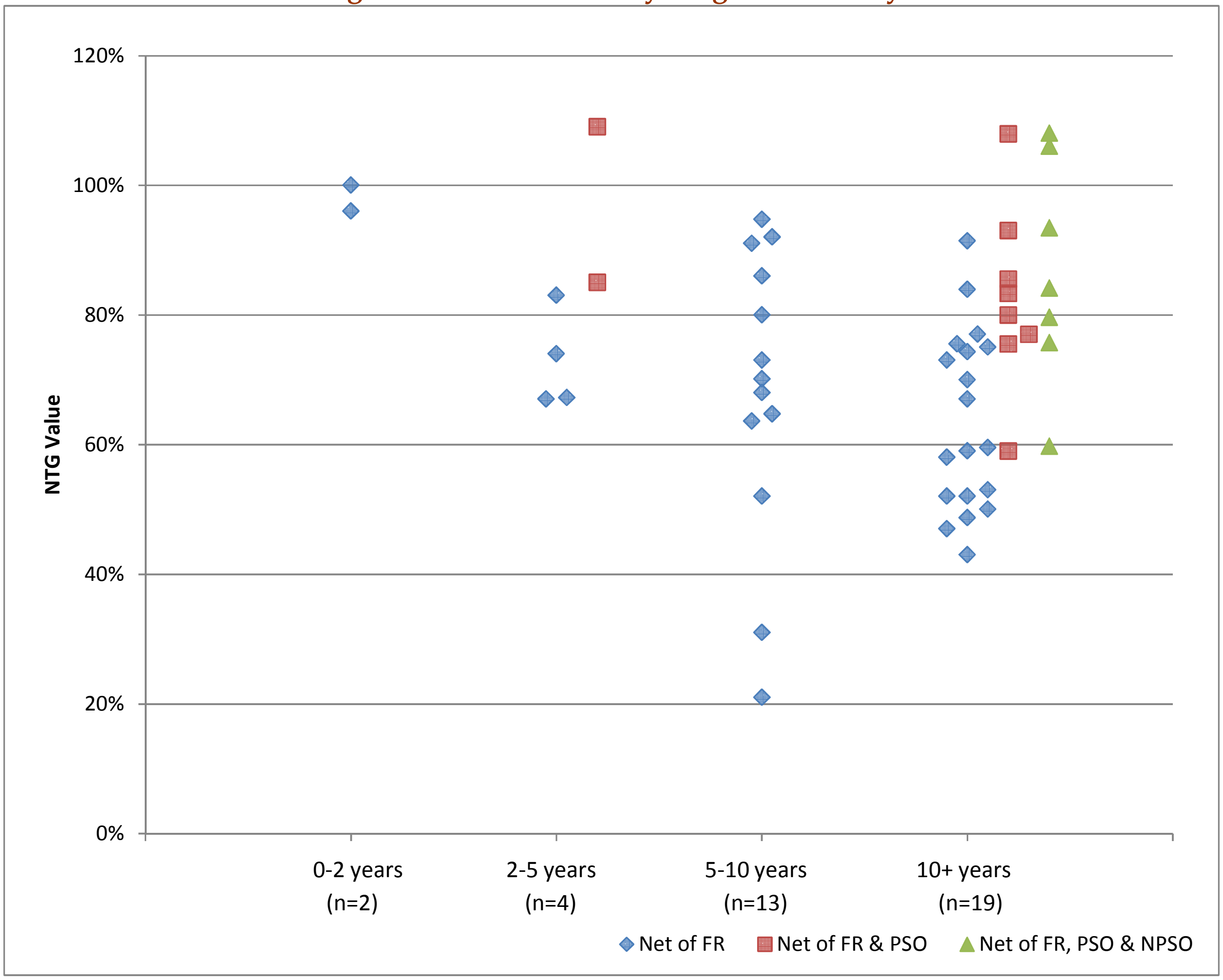
Figure 11. NTG Values by Utility-Type



Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) for each utility-type; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable). Total sample size is 37 instead of 38 because one utility is electric only but reported NTG values for gas savings from electric programs, specifically a retrofit program.

Navigant also explored whether NTG values varied with program maturity and program marketing strategy. Figure 12 summarizes NTG values by program maturity. The majority of programs are in at least their fifth program year, and while the sample size of programs with less than 5 years' experience is limited, there appears to be a trend of lower NTG values (and higher FR) as program experience increases. This finding is not unexpected as markets transform over time raising awareness and knowledge of the benefits of energy efficiency among potential resulting in higher degrees of FR. Jurisdictions which only adjust for FR can be especially prone to declining NTG values over time because what appears like FR in a program's later years may actually be evidence of spillover or market transformation from the program's earlier market interventions.

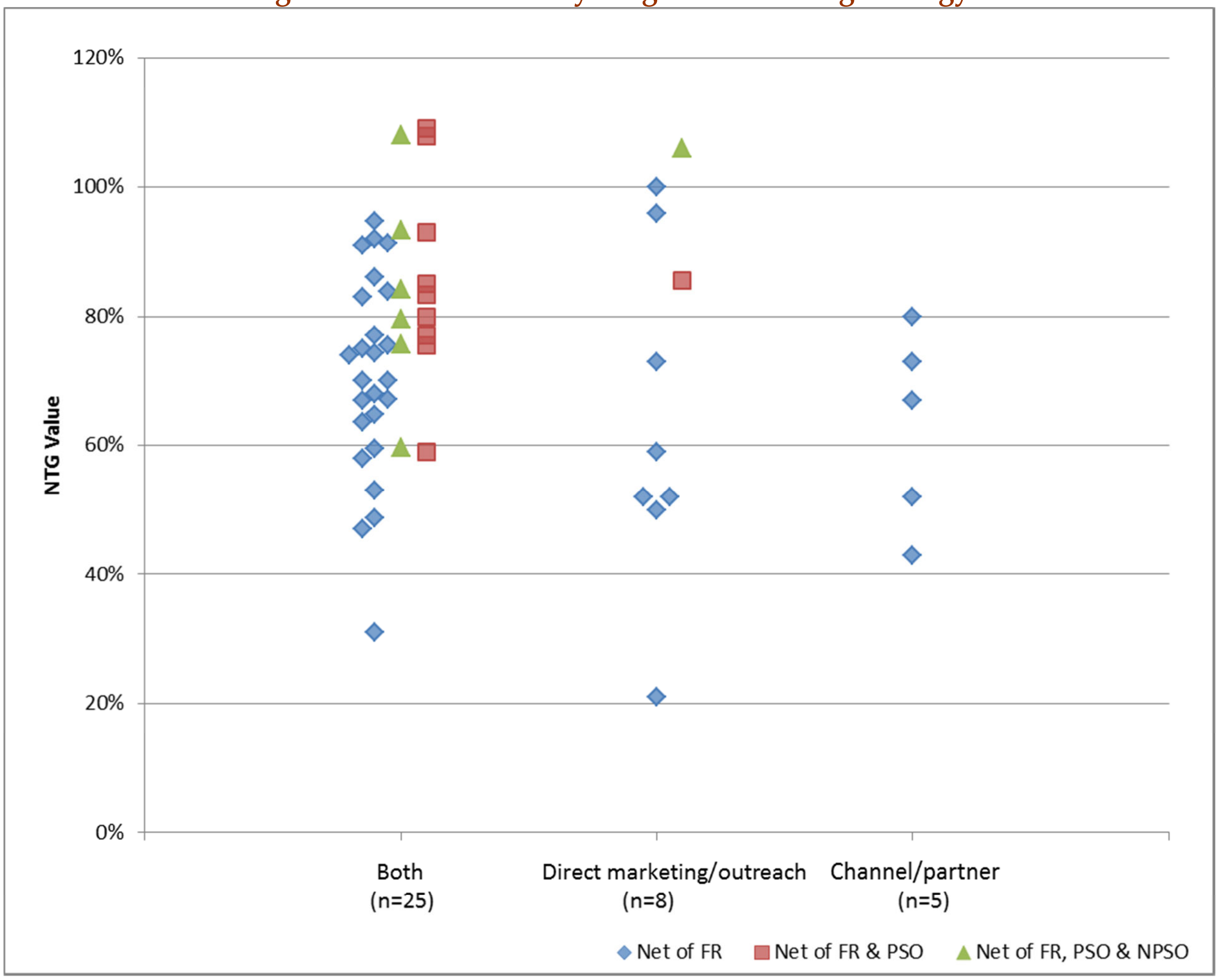
Figure 12. NTG Values by Program Maturity



Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) by program maturity; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable).

Figure 13 summarizes NTG values by program marketing strategy. The majority of programs adopted both a direct marketing/outreach strategy and a channel/partner strategy. As a result, the distribution of NTG values is similar to the high-level summary depicted in Figure 3. Note that the extreme net-of-FR values of 100% and 21% are for programs with a direct marketing/outreach strategy.

Figure 13. NTG Values by Program Marketing Strategy



Source: Navigant analysis. Note that the sample size (n) represent the number of unique NTG values (program-utility-year combinations) by program marketing strategy; the number of data points in the figure exceed the sample sizes because NTG findings are presented as net-of-free ridership, net-of-free ridership & PSO (if applicable), *and* net-of-free ridership, PSO & NPSO (if applicable).

5.3 *Application to Union and Enbridge*

In 2007-2008 Navigant (formerly Summit Blue Consulting) conducted the first attribution study of Union and Enbridge's custom C&I programs to evaluate FR and spillover effects. Table 5 presents the NTG values as well as the values of the individual NTG components.[20]

[20] Non-PSO was also researched but was not factored into the NTG ratio because the energy savings could not be calculated accurately.

Table 5. Summary of Attribution Analysis

Utility	Sector	NTG	Free Ridership	Participant Spillover
Union	**Total**	**56%**	**54%**	**10%**
	Agriculture		0%	
	Commercial Retrofit		59%	
	Industrial		56%	
	Multifamily		42%	
	New Construction		33%	
Enbridge	**Total***	**79%**	**41%**	**21%**
	Agriculture		40%	
	Commercial Retrofit		12%	
	Industrial		50%	
	Multifamily		20%	
	New Construction		26%	

*Free ridership and spillover values include rounding error.
Source: Summit Blue Consulting. 2008. *Custom Projects Attribution Study.* Union Gas Limited and Enbridge Gas Distribution, October 27, 2008.

Following the study, the OEB approved the FR adjustment, but did not approve a spillover value. Currently, Union uses one NTG value for all C&I custom programs, the researched net-of-free ridership value calculated across all sectors (i.e., a FR of 54% and a net-of-free ridership value of 46%). Enbridge, on the other hand, currently uses the researched sector-specific net-of-free ridership values.

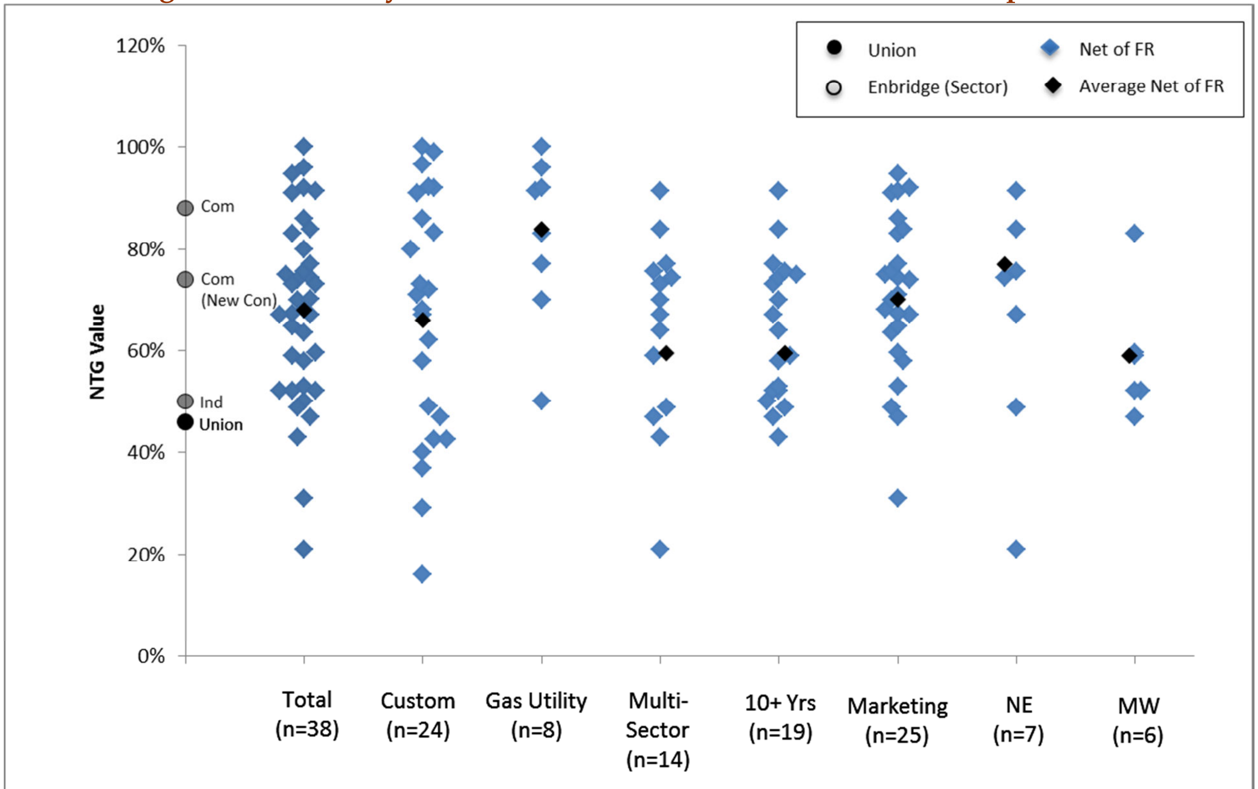
Comparing the current net-of-free ridership values for C&I custom programs (i.e., the researched net-of-free ridership values from the 2007-2008 Union and Enbridge study) to the range of researched values from the jurisdictional review provides context for the current net-of-free ridership values and insight into whether information available from other jurisdictions can be used to estimate NTG values in Ontario. Figure 14 summarizes findings from the review of researched NTG values in selected jurisdictions that are most relevant to Union and Enbridge.[21]

Union and Enbridge are gas-utilities that have been offering custom programs to commercial, industrial, or multi-sector customers for more than 10 years using both a direct marketing and channel/partner marketing strategy. As a result, Figure 14 presents the researched net-of-free ridership values for the following categories: custom program, gas utility, multi-sector, 10+

[21] We only summarize net-of-free ridership values as this summary provides the most information due to the largest sample sizes. Summaries of net of FR and spillover values are presented in Appendix E. Trends resulting from the jurisdictional review of NTG values that consider spillover should be interpreted with caution due to the small sample sizes.

years since program inception, a combination of direct and channel/partner marketing strategy, and northern regions (Northeast and Midwest).[22]

Figure 14. Summary of Relevant Researched Net-of-Free Ridership Values



Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG values (program-utility-year combinations).

The main findings resulting from the review of researched NTG values include the following:

- The NTG values calculated for Union and Enbridge are within the range of NTG values summarized in the review.
- When considering non-residential natural gas programs, NTG values appear to "cluster" between 40% and 90%. Union's NTG value is below the average. Enbridge's NTG value for the commercial sector is above the average while the NTG value for the industrial sector is below the average.

This "clustering" of values becomes less defined when considering other features of program design or implementation that make the NTG values more comparable to Union and Enbridge. For example, the clustering of NTG values for non-residential *custom* gas programs exhibits a wider dispersion without distinct clustering patterns.[23]

---

[22] All programs evaluated in the Midwest were offered in Wisconsin.
[23] Recall that when a NTG value was disaggregated into custom and prescriptive categories, these NTG values were included separately, resulting in more data points.

6. Assessing Options for NTG

Gross savings can usually be estimated quite accurately, however, estimating net savings poses greater challenges. Given the uncertainty around any NTG value, in this section Navigant applies a Decision Analysis approach for organizing information around alternative approaches to setting NTG values.

Navigant took the following steps to conduct the Decision Analysis:

1. Define the benefits of accurate (and costs of inaccurate) NTG values in a general context.
2. Narrow the focus the analysis on one of the benefits/cost for which Navigant had access to data; specifically, the incentives paid to utilities based on the estimated net savings (m^3) achieved.
3. Establish a baseline against which a sensitivity analysis can be conducted where a selected NTG value is assumed to be correct, but in fact is incorrect by some margin of error.[24]
4. Conduct a "value of information" analysis by examining the change in incentive payments resulting from better information on NTG values compared to the cost of obtaining the information (e.g., through NTG research).

This section concludes by organizing the results of the Decision Analysis to provide insight into the tradeoffs from using different approaches to setting an NTG value.

6.1 *Decision Analysis*

The first step in conducting the Decision Analysis is to identify the benefits resulting from more precise NTG values. Three of the primary benefits are described.

- **Program Design and Implementation.** NTG research can be leveraged to improve program design and implementation, ultimately providing greater gross and net savings. For example, FR research can inform decisions to discontinue incenting certain measures and boost the incentives for others. More generally, NTG research will identify what influences the customers' decisions regarding investments in energy efficiency, existing customer knowledge of energy efficiency and equipment operations, and identify aspects of the program that have the greatest influence on the customer's decision to participate in the program. NTG research can also provide insights into how the program is motivating distributors, contractors and other trade allies, and how their

[24] These first three steps are part of a "loss function" analysis which identifies the costs of selecting one NTG value when another value is the actual value. While a traditional loss function analysis focuses on deviations in both the mean value and the precision of the value, for simplicity, this analysis focuses only on precision or range of the values. Navigant did not conduct a more complex analysis because this simple approach provided insight into the value of more precise NTG values, i.e., a reduction in the range of NTG values.

actions might be leading to program spillover. All of this information helps in the design of improved programs.

- **Utility Incentive Payments.** Utilities, and utility shareholders, receive incentive payments for achieving performance goals. NTG values influence the incentive payments that are paid, or not paid, to utilities. More precise estimates of NTG values mitigate the risk that utilities face of receiving incentive payments that are too small, as well as the risk that ratepayers face of making incentive payments that are too large.[25]

- **Energy Savings as a Resource.** Regardless of the NTG value, the gross savings that result from the program are unchanged. (1) From a resource planning perspective, the net effects of the energy efficiency program must be known (i.e., the impacts attributable to the program must not have occurred in the absence of the program). (2) An accurate NTG estimate is important for understanding the equity implications of a program. I.e., participants that receive payments for taking actions that they would have taken even if the program had not existed transfers wealth from ratepayers to the participant. There are policy actions that can be taken to reduce equity issues, such as expanding the program to ensure all ratepayers have access to the program. However, a first step to considering the equity implications of a program is to accurately estimate the level of FR and spillover.

In the Decision Analysis that follows, Navigant focuses on the one benefit/cost for which data was available and for which there is little debate about how to formulate the benefit/cost: utility incentive payments. Union and Enbridge conducted an analysis of the sensitivity of utility incentive payments to changes in the NTG value of custom C&I programs.[26] The sensitivity analysis data was provided by the utilities and was not verified by Navigant.

6.1.1 Union

This section presents an assessment of the value of improved information on NTG values for Union Gas. Table 6 summarizes the impact on utility incentive payments if the custom NTG value is 10 percentage points higher or lower than the current custom NTG value of 0.46 used by Union.[27]

---

[25] While this report highlights the impact of improved precision of NTG values on the incentive payments received by the utilities, one can easily interpret the impact on ratepayers as it is a zero-sum game (i.e., the gain in incentive payments by utilities is a cost to ratepayers and vice versa).
[26] All other data inputs in the incentive payment calculations were held constant.
[27] This analysis assumes Union meets the targeted level of net savings.

Table 6. Value of Information Assessment for Union

	NTG Value for Custom Programs		Incentives	Change in Incentives
Base Case:	**Current NTG** NTG = 0.46	→	Incentives = $2.73 M	
Scenario 1:	**Higher True NTG** NTG = 0.56	→	Incentives = $5.63 M	**(+$2.90 M)**
Scenario 2:	**Lower True NTG** NTG = 0.36	→	Incentives = $0.8 M	**(-$1.93 M)**

Source: Sensitivity Analysis provided by Union.

At the net savings target under current assumptions, if the true custom program NTG value is 10 percentage points higher (Scenario 1) Union should receive an additional $2.9 million in incentive payments for savings achieved. If, instead, the true NTG value is 10 percentage points lower (Scenario 2), Union is receiving $1.93 million in incentives for savings that are not achieved.

A swing of +/- 10 percentage points (i.e., error bounds of +/- 22%) in the custom NTG value causes a swing in incentive payments by almost $3 million on the high side and $2 million on the low side. Assuming a revised custom program NTG value (e.g., by conducting NTG research) would reduce this margin of error by one-half, the error bounds would reduce to +/- 5 percentage points (i.e., +/- 11%) in the NTG value. The swing in incentive payments at the new error bounds would be approximately $1.5 million on the high side and $1 million on the low side. If the cost of revising the NTG values are less than $1 million given these assumed error bounds; then, revising the NTG values *could be judged to be warranted*.

6.1.2 *Enbridge*

This section presents an assessment of the value of improved information on NTG values for Enbridge. Table 7 summarizes the impact on utility incentive payments if the custom program NTG values are 10 percentage points higher or lower than the current custom NTG values used by Enbridge.[28]

[28] This analysis assumes Enbridge meets the targeted level of net savings.

Table 7. Value of Information Assessment for Enbridge

	NTG Value for Custom Programs		Incentives	Change in Incentives
Base Case:	**Current NTG by Program** Commercial = 0.80 Commercial New Construction = 0.74 Industrial = 0.50	→	Incentives = $2.58 M	
Scenario 1:	**Higher True NTG** Commercial = 0.90 Commercial New Construction = 0.84 Industrial = 0.60	→	Incentives = $4.26 M	**(+$1.68 M)**
Scenario 2:	**Lower True NTG** Commercial = 0.70 Commercial New Construction = 0.64 Industrial = 0.40	→	Incentives = $1.45 M	**(-$1.13 M)**

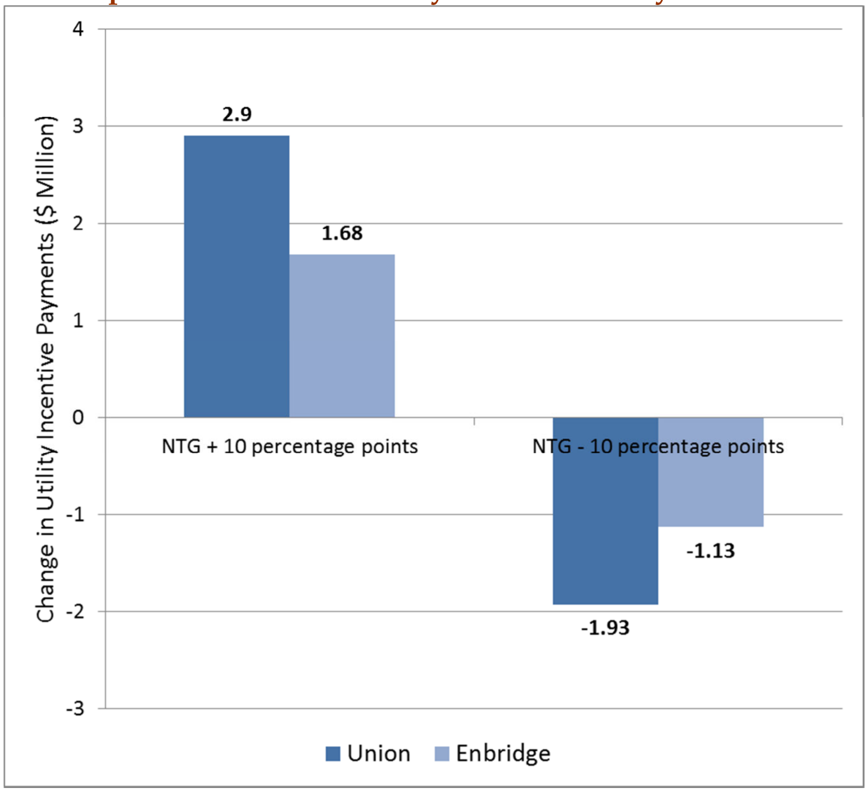
Source: Sensitivity Analysis provided by Enbridge.

At the net savings target under current assumptions, if the true custom program NTG values are 10 percentage points higher (Scenario 1) Enbridge should receive an additional $1.68 million in incentive payments for savings achieved. If, instead, the true custom program NTG values are 10 percentage points lower (Scenario 2), Enbridge is receiving $1.13 million in incentives for savings that are not achieved.

A swing of +/- 10 percentage points in custom program NTG values (i.e., error bounds of +/- 12.5% for commercial, +/- 13.5% for commercial new construction, and +/- 20% for industrial)) causes a swing in incentive payments by almost $2 million on the high side and $1 million on the low side. Assuming revised NTG values (e.g., by conducting NTG research) would reduce this uncertainty by one-half, the error bounds on the NTG values would reduce to +/- 5 percentage points in the NTG values. The swing in incentive payments at the new error bounds would be approximately $1 million on the high side and $0.5 million on the low side. If the cost of revising the NTG values are less than $0.5 million given these assumed error bounds; then, revising the NTG values *could be judged to be warranted*.

Figure 15 illustrates that the sensitivity in incentive payments to changes in custom program NTG values is greater for Union relative to Enbridge. This can be attributed to the fact that custom programs represent a larger share of Union's portfolio of programs, and consequently incentive payments, relative to Enbridge. Nevertheless, for both utilities changes in NTG values have a considerable impact on incentive payments.

Figure 15. Comparison of the Sensitivity of Incentive Payments to NTG Values



Source: Sensitivity analyses provided by Union and Enbridge.

6.2 *General Approaches to NTG*

In this section Navigant describes five general approaches to NTG representing the range of options for addressing net savings, from deeming a NTG value to conducting research to estimate a NTG value. The estimated increased precision of NTG values for each approach is identified as well as the approximate cost of the approach.

Option 1. Transfer NTG Values from Other Research

This approach transfers NTG values from the jurisdictional review. While the jurisdictional review revealed a wide range of NTG values, there is some clustering of values which could be used to inform a deemed value. If this approach is selected, the TEC sub-committee could select a NTG value from this clustering and apply it uniformly to Union and Enbridge's non-residential custom gas programs.

> *Advantages:* The advantage of this approach is that it is simple, straightforward, uniform, and inexpensive.
>
> *Disadvantages:* The disadvantage of this approach is that it does not recognize differences in the performance of different programs, designs, implementation, or program environments (such as economic conditions, energy prices, technology, and attitudes

about climate change); consequently, the transferred values may provide inaccurate estimates of net savings.

Option 2. Adjusted or Scaled NTG Values based on Program Factors

This approach uses a simple scaled or adjusted NTG value from the jurisdictional review to better represent Union and Enbridge programs. A principal objective of the detailed review of researched NTG values was to summarize NTG values based on program factors comparable to Union and Enbridge programs. In particular, Navigant characterized researched NTG values by utility-type, program-type, targeted sector, program maturity, program marketing, and region. If this approach is selected, the TEC sub-committee could select a NTG value accounting for comparable program factors and adjusting appropriately for Union and Enbridge's non-residential custom gas programs. For example, a NTG value that includes spillover should be adjusted to reflect the fact that the majority of studies that consider spillover were conducted in recent years.

Advantages: The advantage of this approach is that it is straightforward, uniform, and inexpensive. In addition, it recognizes differences in the performance of different program factors. Despite the disadvantages outlined below, the additional cost of adjusting or scaling the NTG value is so low that Option 2 is preferred in a pairwise comparison with Option 1.

Disadvantages: The disadvantage of this approach is that due to the small number of researched NTG values with comparable program factors, the credibility of the scaled or adjusted NTG values may come into question, particularly if considering spillover.

Option 3. Align NTG Values using Limited Primary Data Collection

This approach augments comparative NTG values with a small set of selected primary data gathered during the course of program implementation and/or evaluation to enhance the precision of the NTG values. The detailed review revealed that in situations where program design remains consistent, NTG values can vary substantively from one program year to the next, likely due to changes in program implementation or program environment. Interviews with participating and non-participating trade allies, for example, can provide insight into FR and spillover, informing NTG values and requiring relatively limited data collection. If this approach is selected, the TEC sub-committee could select a comparable NTG value using limited primary data collection to adjust NTG values for Union and Enbridge's programs.

Advantages: The advantage of this approach is that it recognizes differences in the performance of different programs, designs, implementation, and program environments while leveraging findings from the detailed review. NTG values will more accurately reflect actual net savings of the program.

Disadvantages: One disadvantage may be the difficulty of developing the appropriate data to collect that represents actual changes in the NTG values. Another disadvantage of this approach is that data collection, even if limited, can be costly; however, if it is incorporated within a program process, e.g., a short survey with the payment of incentives, the costs may be limited.

Option 4. **Full NTG Research Study (After Program Year)**
This approach conducts full-scale evaluations specific to Union and Enbridge programs at the end of the program-year cycle. There various methods for estimating net savings, including, for example, survey-based methods and econometric modeling. The enhanced self-report approach would likely be the most appropriate approach given Union and Enbridge's programs are custom C&I and that identifying the magnitude of individual NTG components is desired.

Advantages: The advantage of this approach is that it recognizes differences in the performance of different programs, designs, implementation, and program environments. Given a full-scale evaluation, NTG values will more accurately reflect actual net savings of the program relative to the limited data collection approach.

Disadvantages: The disadvantage of this approach is that full-scale evaluations are costly. In addition, if not designed properly, NTG research estimates may be biased. Appropriate NTG research contends with a variety of potential biases including, for example, non-response bias, recall bias, reaching the appropriate person, as well as biases related to respondents providing socially desirable responses or legitimizing past behavior.

Option 5. **Integrated/Fast Feedback NTG Estimation**
This approach relies on Integrated Data Collection, or rolling data collection processes, to estimate NTG values specific to Union and Enbridge programs using fast-feedback. Fast-feedback approaches reduce bias associated with NTG estimates, such as recall bias, by surveying participants closer to when the decision-making actually occurs (Energy Trust of Oregon 2012). Collecting data frequently over time assures that less biased estimates of FR are calculated.

Advantages: The advantage of this approach is that it recognizes differences in the performance of different programs, designs, implementation, and program environments. Integrated or Fast Feedback NTG estimation has received a lot of attention due to its ability to help address several key estimation issues – it is easier to target the appropriate people and recall bias is reduced by reducing the time cycle between project completion and data collection.[29] Another possible advantage of this approach is that program implementation staff can see what the NTG is as the program

[29] A number of recent studies estimating NTG make sure that they at least reach appropriate participating customers within 90 days after participating, and conduct surveys on a quarterly cycle. E.g., Summit Blue Consulting, LLC., Skumatz Economic Research Associates, Inc., and Quantec, LLC. 2005. *Commercial/Industrial Performance Program (CIPP) – Market Characterization, Market Assessment and Causality Evaluation.* NYSERDA, March 2005.

is implemented through the year. As a result, there are unlikely to be surprises in the NTG value at the end of a program year. Finally, this approach can actually be less costly than the traditional full research study presented above as Option 4 if data collection leverages existing program implementation efforts. For example, NTG surveys could be linked to the incentive payment process, e.g., one to two weeks after the incentives are paid a short free rider survey could be conducted (usually by phone). This approach is similar to Option 3 with more extensive data collection.

Disadvantages: The primary disadvantage of this approach are issues that may make integration difficult, e.g., appropriate timing of data collection, appropriate survey instruments, appropriate personnel leading the data collection all done along a timeline that is based on the implementation process. In addition, conducting research closer to program participation limits the amount of spillover that can be attributed to the program.

Table 8 provides a summary of the ability of the various approaches to improve the precision of the NTG value and provides an approximate cost of each NTG approach. Though an approximation, Navigant believe a 50% improvement in the precision of custom NTG values at a cost of $0.25 – 0.5 million is a reasonable estimate.[30]

Table 8. Ability of NTG Approaches to Produce More Precise NTG Values

General NTG Approach	Estimated Improved Precision (or Reduced Range) of NTG Value	Cost of NTG Approach per Utility (approximate)
Transfer NTG Values from Other Research	Little change	$3 – 5k
Adjust NTG Values based on Program Factors	Little change	$5 – 10k
Align NTG Values using Limited Primary Data	3 percentage points	$100 – 200k
Full NTG Research Study – After Program Year	5 percentage points	$250 – 500k
Integrated/Fast Feedback NTG Estimation	5 percentage points	$250 – 500k

Source: Navigant analysis.

[30] The cost estimates only reflect the contractor's program evaluation costs and do not include costs incurred by the utility and the TEC. These estimates assume primary data collection on program participants, a set of trade allies, and a sample of non-participants. Actual costs may vary depending on sub-strata and/or sector differentiation (e.g., commercial, commercial new construction, industrial).

7. Summary

The net savings of Union and Enbridge's custom C&I programs were first evaluated by Navigant (formerly Summit Blue Consulting) in 2007-2008. Following the study, the OEB approved the FR adjustment, but did not approve a spillover value. Since that time, there have been a host of program environment changes, including economic conditions, energy prices, advances in technology, as well as changes in the design and delivery of the custom programs. As a result, a key priority for Ontario's TEC sub-committee is to update the FR adjustment factor and reconsider the spillover adjustment.

As an initial step, the TEC sub-committee contracted Navigant to provide information to assist the TEC sub-committee in their deliberations on the appropriate approach to NTG for natural gas DSM programs in Ontario. Through a jurisdictional review of the approach to net savings, and a review of researched NTG values for programs comparable to Union and Enbridge's custom C&I gas programs, Navigant provides an assessment of the various approaches to NTG. Following is a summary of key findings:

Approach to Net Savings

- The majority of jurisdictions with ratepayer funded energy efficiency programs conduct NTG research, though only half adjust gross savings based on research.
- U.S. states that provide a performance incentive mechanism for utilities or program administrators are more likely to make deemed or researched NTG adjustments.
- There appears to be a trend towards considering participant and NPSO in NTG research in recent years.

Researched NTG Values in Selected Jurisdictions

- Navigant identified a total of 19 documents that conducted NTG research of non-residential gas programs that calculated 38 distinct results.
- Researched net-of-free ridership values for non-residential gas programs exhibit a wide dispersion (21% to 100%) with a slight "clustering" of values between 40% and 90%.
- Trends in researched NTG values that consider spillover, as well as trends when considering specific program characteristics, should be interpreted with caution due to the small sample sizes.
- Union and Enbridge's current NTG values are within the range of researched values. Union's NTG value is below the average value. Enbridge's NTG value for the commercial sector is above the average value while the NTG value for the industrial sector is below the average value.

Assessing Options for NTG

- There are a variety of benefits of accurate (costs of inaccurate) NTG values that could be considered; utility incentive payments are just one.
- Improving the precision of NTG values has a sizable impact on incentive payments.
- NTG values with a margin of error of +/- 10 percentage points have roughly a $1 - $3 million impact on utility incentive payments.
- Alternate NTG approaches could improve the precision of NTG values by approximately 50% at an approximate cost of $0.25 - $0.50 million per utility.

The objective of this report is to provide information to assist the TEC sub-committee in their determination on the appropriate approach to NTG for DSM programs in Ontario, and not to provide a specific recommendation. While this report is not comprehensive in addressing all potential considerations, such as other benefits of accurate (costs of inaccurate) NTG values, it provides important information relevant to the discussion. In addition to summarizing the regulatory and methodological approach taken by other jurisdictions, and summarizing NTG values for programs with characteristics similar to Union and Enbridge's custom C&I programs, Navigant provides insight into the risks associated with inaccurate NTG values and the approximate cost of mitigating those risks.

Appendix A. General and Methodological References

Kushler, Martin, Nowak, Seth, and Patti White. 2012. *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs.* American Council for an Energy-Efficient Economy. Available from: http://www.aceee.org/sites/default/files/publications/researchreports/u122.pdf.

MEEA. *Energy Efficiency Policies and Practices in Midwestern States.* Accessed January 23, 2013: http://mwalliance.org/policy/energy-efficiency-policies-and-practices-midwestern-states.

Messenger, Mike et al. 2010. *Review of Evaluation, Measurement and Verification Approaches Used to Estimate the Load Impacts and Effectiveness of Energy Efficiency Programs.* Lawrence Berkeley National Lab, April 2010. Available from: http://eetd.lbl.gov/ea/emp/reports/lbnl-3277e.pdf

Saxonis, W. 2007. *Free Ridership and Spillover: A Regulatory Dilemma.* Energy Program Evaluation Conference, Chicago, IL.

The Cadmus Group. 2012. *Assessment of Energy and Capacity Savings Potential in Iowa.* Iowa Utility Association, February 28, 2012.

The Cadmus Group. 2011. *Net-to-Gross: Updating Research.* Salt River Project, December 20, 2011.

Appendix B. Summary of NTG Values for Excluded Programs

There are two jurisdictions/programs that were excluded from the detailed review but provide additional information to the TEC sub-committee on NTG values in other jurisdictions.

California's **Savings by Design** program is a custom C&I program that has been offered for more than 10 years. This program was excluded from our review because the methodology used to calculate net savings was different from the approach used by the remaining documents reviewed. In particular, responses to a FR survey were used to adjust the baseline of an engineering model. The NTG ratio was then calculated as the ratio of gross to net savings, as estimated by the engineering model. This approach accounts for interactive effects between measures and resulted in NTG values greater than 100%, even though only a FR adjustment was made. The table below summarizes the NTG values for Savings by Design.

NTG Values for Savings by Design

Category	NTG Value
Combined	87%
PG&E	66%
SDG&E	109%
SCE	101%
SCG	25%

Source: RLW Analytics. 2008. *An Evaluation of the 2004-2005 Savings by Design Program.* California Public Utilities Commission, October 2008.

NYSERDA has implemented a number of C&I programs with custom components, and include both electric and gas measures. Relevant programs include: **Industrial and Process Efficiency, Flexible Technical Assistance, C&I Performance, and New Construction Program.** Recent research estimates NTG values using a rigorous methodology, but were excluded from our review because the values were not reported separately for electric and gas measures. The Table below summarizes NTG values for these programs, where NTG = 1 – Free Ridership + Participant Spillover + Non-Participant Spillover.

NTG Values for NYSERDA Programs

Program	NTG Value
Industrial and Process Efficiency	104%
Flexible Technical Assistance	117%
New Construction Program	116%
C&I Performance	123%

Sources: Megdal & Associates. 2012. *NYSERDA 2009-2010 Industrial and Process Efficiency Program Impact Evaluation Report; Impact Evaluation: NYSERDA 2007-2009 FlexTech Program*; *New Construction Program (NCP) Impact Evaluation Report for Program Years 2007-2008*;
Summit Blue Consulting. 2007. *Commercial and Industrial Performance Program (CIPP): Market Characterization, Market Assessment and Causality Evaluation.* NYSERDA, May 2007.

NAVIGANT

Appendix C. Annotated Bibliography of Documents Reviewed

2004/2005 Statewide Express Efficiency and Upstream HVAC Program Impact Evaluation	
Author and Date	Itron and KEMA. December 31, 2008.
Jurisdiction	California
Utilities	Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Southern California Gas Company
Program Name	Express Efficiency Program
Program Summary	The Express Efficiency program targets small and medium-sized commercial customers (electricity demand less than 500 kW; annual gas consumption less than 250,000 therms) providing financial incentives to end-users for the installation of selected energy efficient electric and gas technologies (e.g., lighting, refrigeration, air conditioning, food service, agricultural, and gas technologies). The program implements a marketing strategy directly with the end-user and through upstream partners (e.g., vendors).
Program Year	2004-2005
NTG	0.51
Free-Ridership	NTG=1-FR; 0.49
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Self-report. Participant surveys were completed by end-users. The free-ridership score was the average of scores from two methodologies using participant survey data. One methodology adjusts for timing.

Note that this evaluation study also addresses the Upstream HVAC/Motors; however, no gas savings were reported under this program in 2004-2005.

2004-2005 Statewide Nonresidential Standard Performance Contract Program Measurement and Evaluation Study	
Author and Date	Itron. September 30, 2008.
Jurisdiction	California
Utilities	Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison
Program Name	Nonresidential Standard Performance Contract Program
Program Summary	This program provides financial incentives for custom cost effective energy saving retrofits of existing facilities. While targeted at large and medium-sized businesses, small businesses can participate if they are ineligible for incentives through California's Express Efficiency program. Major measure types include: lighting and lighting controls, variable speed-drive for motors, HVAC, and industrial processes. Pacific Gas & Electric and San Diego Gas & Electric offer incentives for energy efficiency gas measures, with incentives of $1.00 per therm.
Program Year	2004-2005
NTG	0.57
Free-Ridership	0.43
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Self-report. Participant surveys were completed by end-users. The sample used for gross impact analysis was also used for net impact analysis. The free-ridership score was the average of scores from two methodologies using participant survey data, in which one methodology adjusted for timing.

2006-2008 Retro-Commissioning Impact Evaluation	
Author and Date	SBW Consulting. February 8, 2010.
Jurisdiction	California
Utilities	Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Southern California Gas
Program Name	More than two dozen Retro-Commissioning programs.
Program Summary	This report presents evaluation, measurement and verification activities for over two dozen commercial retro-commissioning programs that target high impact measures (i.e. contribute more than 1% of utilities' savings portfolio). Given the number of programs, program design varies and may include technical assistance and/or financial incentives.
Program Year	2006-2008
NTG	PG&E: 0.86 SCE: 0.91 SCG: 0.92 SDG&E: 0.68
Free-Ridership	PG&E: 0.14 SCE: 0.09 SCG: 0.08 SDG&E: 0.32
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Enhanced self-report. Includes participant surveys, vendor surveys, program staff interviews, and file reviews. In some cases supplemental questions were asked of participant decision-makers. Free-ridership estimate is based on survey questions about timing and selection, program influence, and likelihood. Timing adjustments are included. When multiple elements feed into one score, the maximum (representing highest program influence) is used.

2006-2008 Evaluation Report for PG&E Fabrication, Process and Manufacturing Contract Group	
Author and Date	Itron. February 3, 2010.
Jurisdiction	California
Utilities	Pacific Gas & Electric
Program Name	Program administered by PG&E: • Fabrication, Process and Manufacturing Programs administered by a third-party: • Heavy Industry Energy Efficiency Program • California Wastewater Process Optimization Program • Energy Efficiency Services for Oil Production • Wastewater Process Efficiency Initiative • Refinery Energy Efficiency Program • Assessment, Implementation and Monitoring • Value and Energy Stream Mapping Advantage Plus • Energy Efficiency of Compressed Systems • C&I Boiler Efficiency Program
Program Summary	The Pacific Gas & Electric Fabrication, Process and Manufacturing contract group is comprised of one PG&E program and nine third-party programs. These programs provide technical assistance and financial incentives for the installation of custom and prescriptive electric and gas measures in industrial facilities. Eligible sectors include industrial and manufacturing, water supply and treatment, wastewater, oil and gas extraction, refining, and production. Major measure types include: boiler upgrades and controls, boiler heat recovery, pipe and duct insulation, HVAC, process improvements, as well as various electric measures.
Program Year	2006-2008
NTG	0.31
Free-Ridership	0.69
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Enhanced self-report. Includes participant surveys, vendor surveys, program staff interviews, and file reviews. In some cases supplemental questions were asked of participant decision-makers. Free-ridership estimate is based on survey questions about timing and selection, program influence, and likelihood. Timing adjustments are included. When multiple elements feed into one score, the maximum (representing highest program influence) is used.

Evaluation of the Southern California Gas Company 2004-2005 Non-Residential Financial Incentives Program	
Author and Date	ECONorthwest. June 6, 2006.
Jurisdiction	California
Utilities	Southern California Gas Company
Program Name	Nonresidential Financial Incentives Program
Program Summary	This program provides technical assistance, education, and financial incentives for prescriptive and custom energy efficiency gas measures. This program is targeted at small and medium-sized customers, spanning the commercial, industrial and agricultural sectors. There are three program offerings: • The Commercial Food Service Equipment Rebate program offering provides financial incentives for prescriptive measures. Examples include ovens, broilers, griddles, and fryers. • The Nonresidential Equipment Replacement program offering provides financial incentives for the replacement of existing gas technologies with energy efficient alternative. Examples include industrial furnaces, ovens, dryers, washers, and more. • The Nonresidential Energy Conservation program offering provides financial incentives for energy efficiency retrofits and energy efficiency improvements to industrial processes. Examples include heat-recovery, process steam improvements, and high-efficiency burner replacements.
Program Year	2004-2005
NTG	0.70
Free-Ridership	0.30
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Self-report. Participant surveys were completed by end-users. Three methodologies were implemented though a preferred methodology is identified. This methodology calculates a probability of influence based on the influence of the financial incentive, program representatives, and adjusts for timing.

Comprehensive Process and Impact Evaluation of the Business Heating Efficiency Program - Colorado	
Author and Date	TetraTech. December 14, 2011.
Jurisdiction	Colorado
Utilities	Xcel Energy
Program Name	Business Heating Efficiency Program
Program Summary	This program provides financial incentives to commercial customers for prescriptive energy efficient gas measures. Major measure types include: new high efficiency hot water boilers and furnaces, improvements to existing boilers and hot water heaters, or boiler tune-ups to maintain peak operating efficiency.
Program Year	2011
NTG	0.85
Free-Ridership	0.26
Participant Spillover	0.11 (Like)
Non-Participant Spillover	N/A – Conducted interviews with HVAC trade allies but were unable to quantify NPSO.
Research Method	Self-report. Surveys include questions about the timing and selection of program measures, the influence of the program (whether rebate, recommendation, or other program intervention), and the likelihood of various actions now and in the future had the program not been available. Methodology adjusts free-ridership score if past program participation in any Xcel Energy program influences the decision to install a measure. Spillover is considered if it occurs within 4 years.

2011 C&I Natural Gas Programs Free-Ridership and Spillover Study	
Author and Date	TetraTech. June 26, 2012.
Jurisdiction	Massachusetts
Utilities	National Grid, NSTAR, Unitil, Berkshire Gas, Columbia Gas, and New England Gas
Program Names	All C&I custom and prescriptive gas programs were included in this evaluation. • National Grid programs include: New Construction (custom and prescriptive), Retrofit (custom and prescriptive), Direct Install (prescriptive) • NSTAR programs include: Business Solutions (custom), Construction Solutions (custom), Small Business Solutions (custom and prescriptive) • Columbia Gas programs include: Large Custom, Small Custom, Prescriptive • Unitil programs include: Large Retrofit (custom and prescriptive), Gas Networks (prescriptive), Small Direct Install (prescriptive) • New England Gas programs include: Retrofit (custom), Lost Opportunity (prescriptive), Direct Install (prescriptive) • Berkshire Gas programs include: Custom, Prescriptive
Program Summary	These programs provide financial incentives for installing custom and prescriptive energy efficient gas measures.
Program Year	2011
NTG	0.79
Free-Ridership	0.305
Participant Spillover	0.085 (Like)
Non-Participant Spillover	0.007
Research Method	Enhanced self-report. Combination of participant (decision-makers) and trade ally surveys. Surveys include questions about likelihood of equivalent efficiency and quantity of program measures, as well as the timing. Questions were also included about the influence of program and various features of the program, as well as the influence of participating in past programs. Free-ridership and spillover estimates are weighted by therm savings and the probability of being surveyed. Surveys with design professionals and equipment vendors were used to calculate free-ridership in cases where the decision was heavily influenced by the design professional/equipment vendor, as well as to calculate NPSO.

Achieving Natural Gas Savings Goals: Commercial Heating Programs Heat It Up	
Author and Date	TetraTech and Xcel Energy. 2012 ACEEE Summer Study on Energy Efficiency in Buildings.
Jurisdiction	Minnesota
Utilities	Xcel Energy
Program Name	Business Heating Efficiency Program
Program Summary	This program provides financial incentives to commercial customers for prescriptive energy efficient gas measures. Major measure types include: new high efficiency hot water boilers and furnaces, improvements to existing boilers and hot water heaters, or boiler tune-ups to maintain peak operating efficiency.
Program Year	2011
NTG	1.09
Free-Ridership	0.17
Participant Spillover	0.26 (Like)
Non-Participant Spillover	N/A – Conducted interviews with HVAC trade allies but were unable to quantify NPSO.
Research Method	Self-report. Surveys include questions about the timing and selection of program measures, the influence of the program (whether rebate, recommendation, or other program intervention), and the likelihood of various actions now and in the future had the program not been available. Methodology adjusts free-ridership score if past program participation in any Xcel Energy program influences the decision to install a measure. Spillover is considered if it occurs within 4 years.

Note: Research method is the method employed by TetraTech in the evaluation of Colorado's Xcel Energy Business Heating Efficiency Program which is the same method employed in Minnesota. This paper relies on TetraTech's evaluation to report NTG values, though the report itself is not publicly available.

New Jersey's Clean Energy Program Energy Impact Evaluation: SmartStart Program Impact Evaluation	
Author and Date	KEMA. September 17, 2009.
Jurisdiction	New Jersey
Utilities	New Jersey's Clean Energy Program
Program Name	SmartStart Buildings Program (New Construction, Schools, and Retrofit program)
Program Summary	This program provides financial incentives and technical assistance for energy efficient measures in new construction, retrofits of existing buildings, and schools.
Program Year	2006
NTG	0.21
Free-Ridership	0.79
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Self-report. Surveys include questions about likelihood of equivalent efficiency and quantity of program measures, as well as the timing. Free-ridership measures for timing, efficiency, and quantity are multiplied to determine free-ridership. Adjustments to free-ridership score based on timing is made. The sample size for Schools and New Construction programs is small.

Evaluation of 2011 DSM Portfolio	
Author and Date	ADM Associates. June 29, 2012.
Jurisdiction	New Mexico
Utilities	New Mexico Gas Company
Program Names	Commercial Solutions, Commercial High Efficiency Water Heater, Commercial Energy Star Food Service, and SCORE Pilot
Program Summary	These programs provide financial incentives for custom and prescriptive measures installed by commercial customers. • The Commercial Solutions program includes two program offerings: direct install of low flow faucet aerators and pre-rinse spray valves, and custom incentives of up to $0.75 per therm for custom measures, such as: water heating, HVAC, building envelope, and industrial processes. The SCORE Pilot is similar to the Commercial Solutions program but is targeted at K-12 school districts. • The Commercial Energy Star Food Services program provides prescriptive rebates for commercial kitchen measures, such as fryers, dishwashers, convection ovens, and commercial griddles. • The Commercial High Efficiency Water Heater program provides financial incentives for storage tank and tankless water heaters.
Program Year	2011
NTG	Commercial Solutions: 0.96 Commercial High Efficiency Water Heater: 1.00 Commercial Energy Star Food Service: 1.00 SCORE Pilot: 1.00
Free-Ridership	Commercial Solutions: 0.04
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Self-report. Surveys include questions about the financial ability to purchase measures without the program, the importance of the financial incentive, prior planning to purchase measures, and demonstrated behavior in purchasing similar measures without a financial incentive.

Fast Feedback Results	
Author and Date	Energy Trust of Oregon. April 25, 2012.
Jurisdiction	Oregon
Utilities	Energy Trust of Oregon
Program Names	Existing Buildings Program, Production Efficiency Program
Program Summary	Descriptions of programs not included in study. Information that follows is from the Energy Trust of Oregon's website (http://energytrust.org) Existing Buildings program provides custom and prescriptive financial incentives to existing commercial facilities. Major gas measure types include: HVAC, furnace, radiant heater, hot water tanks, tankless water heaters, boilers, and steam traps. Production Efficiency program provides technical assistance and financial incentives for energy efficiency improvements for industrial processes, including manufacturing, agriculture, and water/wastewater treatment. Major measure types include: motors, compressed air, variable speed drives, refrigeration, pumps, fans, and lighting.
Program Year	Q2 2010
NTG	Existing Buildings: 0.73 Existing Multifamily: 0.52 Production Efficiency: 0.80
Free-Ridership	Existing Buildings: 0.27 Existing Multifamily: 0.48 Production Efficiency: 0.20
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Self-report. Surveys are conducted with participants that received a financial incentive within the previous month. The survey is designed to be completed in no more than 5 minutes and consists of 10 questions or less. Free-ridership is calculated as the sum of a project change score and an influence score. The project change score is based on survey questions about the actions the customer would have taken if the program was not available. Influence questions ask about the influence of the program, trade ally influence, etc.

Impact and Process Evaluation of the 2006-2007 Building Efficiency Program	
Author and Date	Research Into Action and the Cadmus Group. August 3, 2009.
Jurisdiction	Oregon
Utilities	Energy Trust of Oregon
Program Name	Building Efficiency Program
Program Summary	This program provides technical assistance and financial incentives for electric and gas energy-saving measures installed by commercial and institutional customers. Financial incentives are provided for both prescriptive and custom measures. Major measure types include: lighting, motors, HVAC, gas space and water heaters, restaurant equipment, and insulation.
Program Year	2006-2007
NTG	0.70
Free-Ridership	0.30
Participant Spillover	Qualitative assessment.
Non-Participant Spillover	N/A
Research Method	Self-report. Survey questions consider program influence, intentions for the project without the program, and budget.

Evaluation of Building Efficiency Program 2004 &2005	
Author and Date	ADM Associates. February 2009.
Jurisdiction	Oregon
Utilities	Energy Trust of Oregon
Program Name	Building Efficiency Program
Program Summary	This program provides technical assistance and financial incentives for electric and gas energy-saving measures installed in existing commercial, institutional, and agricultural facilities. Financial incentives are provided for both prescriptive and custom measures. Major measure types include: lighting, motors, HVAC, gas space and water heaters, restaurant equipment, and insulation.
Program Year	2004-2005
NTG	2004: 0.65 2005: 0.95
Free-Ridership	2004: 0.35 2005: 0.05
Participant Spillover	Qualitative assessment.
Non-Participant Spillover	N/A
Research Method	Self-report. Survey questions consider program influence, intentions for the project without the program/prior planning, and previous experience with the measure. Each question is binary (i.e. yes/no). Partial free-ridership is explored through questions about efficiency level, quantity and timing.

Impact and Process Evaluation of the 2006-2007 New Building Efficiency Program	
Author and Date	ADM Associates. June 2009.
Jurisdiction	Oregon
Utilities	Energy Trust of Oregon
Program Name	New Building Efficiency Program
Program Summary	This program provides technical assistance and financial incentives for electric and gas energy-saving measures installed in new commercial facilities or commercial facilities undergoing major renovation. Major measure types include: lighting, HVAC, motors, energy management systems, and washer/dryers.
Program Year	2006-2007
NTG	0.67
Free-Ridership	0.33
Participant Spillover	Qualitative assessment.
Non-Participant Spillover	N/A
Research Method	Self-report. Participant surveys were conducted. Free-ridership estimates are based on survey questions that ask about the influence of the program, the participants' intentions for the project if the program were not available, and their financial ability to install the measures if the program were not available.

C&I Energy Efficiency Retrofit Custom Programs Portfolio Evaluation	
Author and Date	Navigant Consulting. February 3, 2012.
Jurisdiction	Washington
Utilities	Puget Sound Energy
Program Name	Custom Grant Program
Program Summary	This program provides financial incentives for the installation of custom energy efficient measures as part of a retrofit, new construction, or expansion of existing facilities project. Major measure types include: lighting, boilers, HVAC, variable speed drives, and process improvements.
Program Year	2010-2011
NTG	1.02-1.1
Free-Ridership	0.27
Participant Spillover	0.07-0.09 (inside like); 0.04-0.05 (outside like)
Non-Participant Spillover	0.18-0.23
Research Method	Self-report. Surveys of participants and non-participants were conducted. Free-ridership was estimated based on survey questions about timing, efficiency, quantity, and program importance. Spillover calculated as a factor of savings derived from spillover project based on program influence. Savings were assumed equal to savings by in-program projects (by measure-type). Similar calculations were conducted for NPSO.

Focus on Energy Evaluation: Business Programs – Additional Looks at Attribution	
Author and Date	PA Consulting Group and KEMA. February 26, 2010.
Jurisdiction	Wisconsin
Utilities	Focus on Energy
Program Name	The names of specific program offerings are not reported.
Program Summary	Various programs provide technical assistance and financial incentives for implementing cost effective energy efficiency measures. Both prescriptive and custom incentives are available. Targeted sectors include commercial, industrial, agricultural, and institutional. Major measure types include: boilers, HVAC, refrigeration, water heater, expanded processes, and lighting.
Program Year	July 1, 2007 through September 30, 2008
NTG	0.52
Free-Ridership	0.48
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Enhanced self-report. Surveys of participants and trade allies were conducted. Free-ridership survey questions ask about timing, efficiency, and the quantity of measures installed if the program were not available. These free-ridership estimates are multiplied (e.g., NTG=1-FqFeFt). Surveys include consistency checks. NTG estimates based on participant survey data is compared to estimates based on trade ally survey data. The maximum value is selected.

Focus on Energy Evaluation: Business Programs Impact Evaluation Report – Last Quarter of Calendar Year 2009 and First Two Quarters of Calendar Year 2010	
Author and Date	TetraTech and KEMA. January 27, 2011.
Jurisdiction	Wisconsin
Utilities	Focus on Energy
Program Name	The names of specific program offerings are not reported.
Program Summary	Various programs provide technical assistance and financial incentives for implementing cost effective energy efficiency measures. Both prescriptive and custom incentives are available. Targeted sectors include commercial, industrial, agricultural, and institutional. Major measure types include: boilers, HVAC, refrigeration, water heater, expanded processes, and lighting.
Program Year	October 1, 2009 through June 30, 2010
NTG	2009: 0.60 2010: 0.47
Free-Ridership	2009: 0.40 2010: 0.53
Participant Spillover	(Identified in a separate study as 0.002%)
Non-Participant Spillover	N/A
Research Method	Enhanced self-report. Surveys of participants and trade allies were conducted. Free-ridership survey questions ask about timing, efficiency, and the quantity of measures installed if the program were not available. These free-ridership estimates are multiplied (e.g., NTG=1-FqFeFt). Surveys include consistency checks. NTG estimates based on participant survey data is compared to estimates based on trade ally survey data. The maximum value is selected.

Focus on Energy Evaluation: Semiannual Report (Second Half of 2009)	
Author and Date	PA Consulting Group. April 23, 2010.
Jurisdiction	Wisconsin
Utilities	Focus on Energy
Program Name	The names of specific program offerings are not reported.
Program Summary	Various programs provide technical assistance and financial incentives for implementing cost effective energy efficiency measures. Both prescriptive and custom incentives are available. Targeted sectors include commercial, industrial, agricultural, and institutional. Major measure types include: boilers, HVAC, refrigeration, water heater, expanded processes, and lighting.
Program Year	Q3 and Q4 2009
NTG	0.59
Free-Ridership	0.41
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Enhanced self-report. Participant surveys and surveys with trade allies were conducted. Free-ridership survey questions ask about timing, efficiency, and the quantity of measures installed if the program were not available. Conducted a sensitivity analysis on treatment of timing using methodologies adopted in other jurisdictions finding little variation.

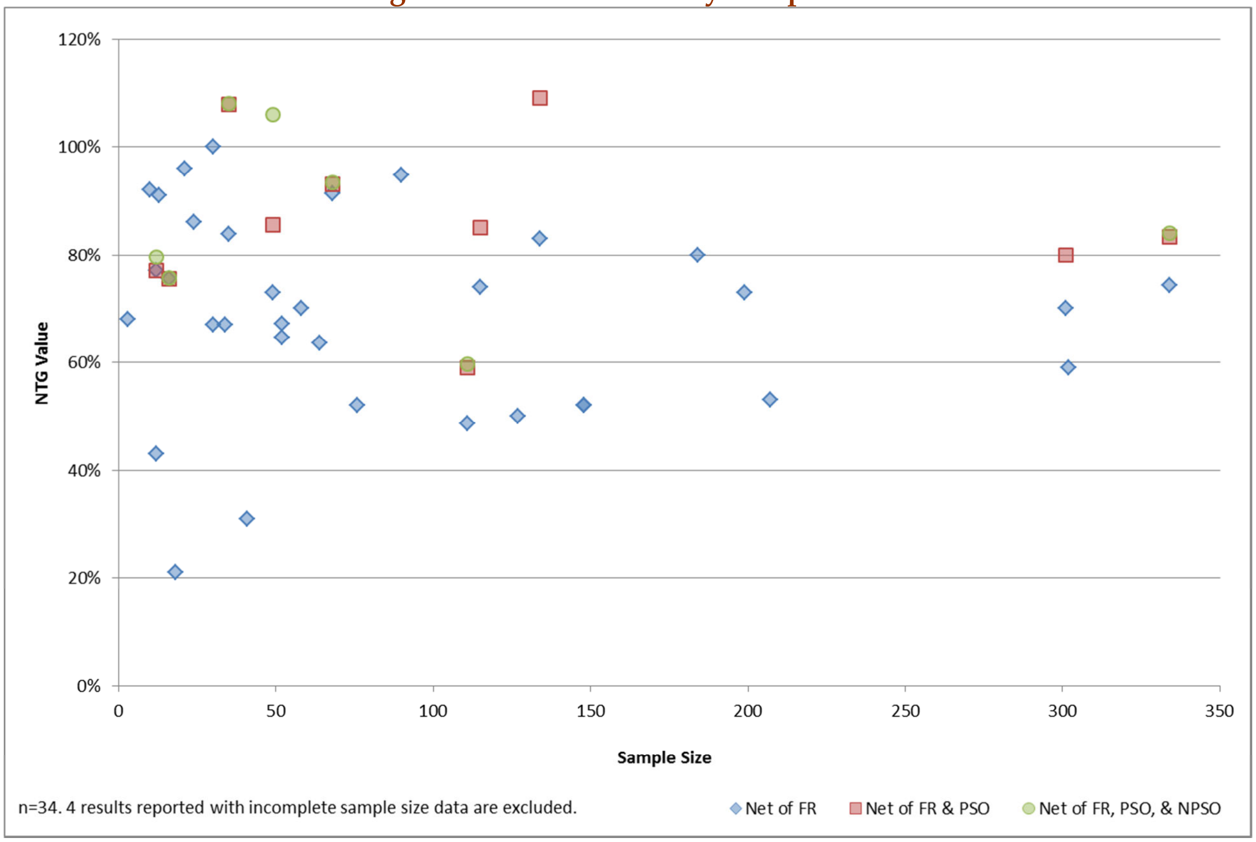
Focus on Energy Evaluation: Semiannual Report (First Half of 2009)	
Author and Date	PA Consulting Group. October 19, 2009.
Jurisdiction	Wisconsin
Utilities	Focus on Energy
Program Name	The names of specific program offerings are not reported.
Program Summary	Various programs provide technical assistance and financial incentives for implementing cost effective energy efficiency measures. Both prescriptive and custom incentives are available. Targeted sectors include commercial, industrial, agricultural, and institutional. Major measure types include: boilers, HVAC, refrigeration, water heater, expanded processes, and lighting.
Program Year	A1 and A2 2009
NTG	0.52
Free-Ridership	0.48
Participant Spillover	N/A
Non-Participant Spillover	N/A
Research Method	Enhanced self-report. Participant surveys and surveys with trade allies were conducted. Free-ridership survey questions ask about timing, efficiency, and the quantity of measures installed if the program were not available.

NAVIGANT

Appendix D. NTG Values by Sample Size

The figure below summarizes NTG values by sample size. Sample sizes are reported in raw form and do not reflect the percent of participants or percent of energy savings. Consequently, this Figure should be interpreted with caution.

Figure D1. NTG Values by Sample Size

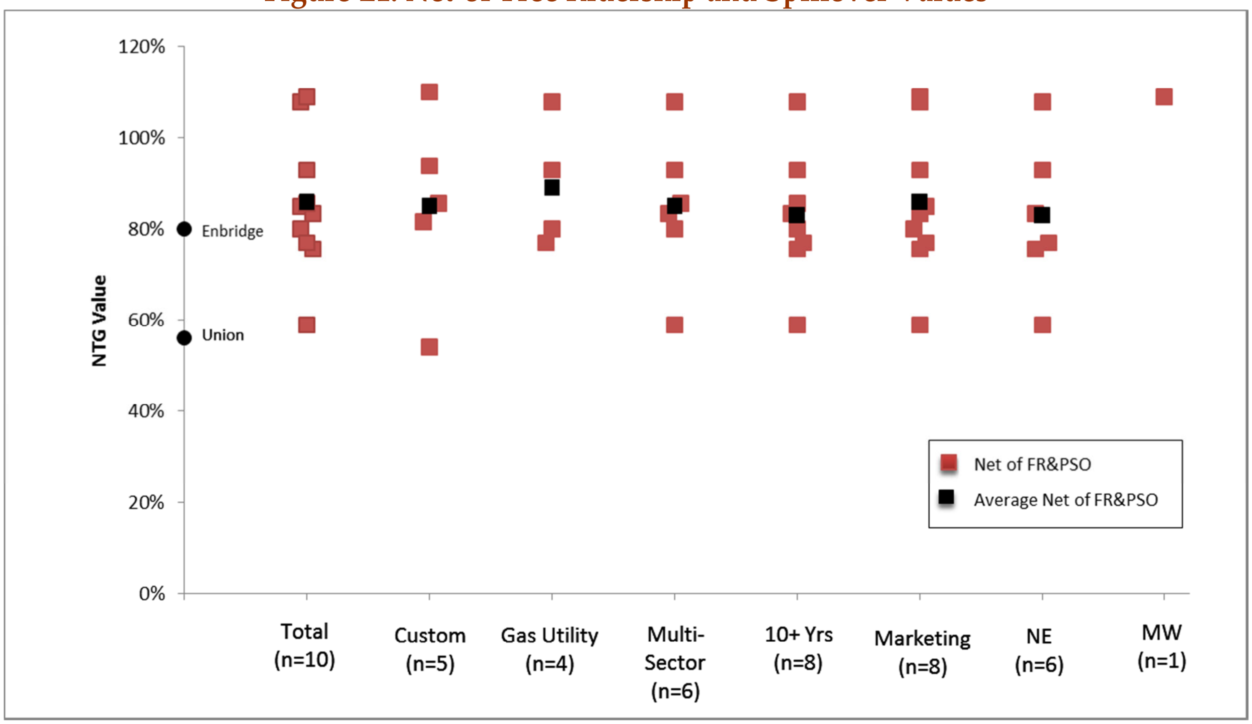


Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG results (program-utility-year combinations) reported in the 19 studies.

Appendix E. Researched Net-of-Free Ridership and Spillover Values

The figure below summarizes net-of-free ridership and PSO values that are most relevant to Union and Enbridge programs. In particular, values are presented for the following categories: custom program, gas utility, multi-sector, 10+ years since program inception, a combination of direct and channel/partner marketing strategy, and northern regions (Northeast and Midwest). Note that the values reported for Union and Enbridge are researched values representing all sectors resulting from the 2007-2008 attribution study. Caution should be used in interpreting trends due to the small sample sizes. Nevertheless similar trends emerge. Enbridge and Union NTG values are below the average values.

Figure E1. Net-of-Free Ridership and Spillover Values



Source: Navigant analysis. Note that the sample size (n) represents the number of unique NTG results (program-utility-year combinations).

A National Review of Best Practices and Issues in Attribution and Net-to-Gross: Results of the SERA/CIEE White Paper

Lisa A. Skumatz, Skumatz Economic Research Associates, Inc.
Edward Vine, California Institute for Energy and Environment

ABSTRACT

Energy efficiency evaluation / attribution methods have reached a point that they must evolve in order to provide credible evaluation results for the next generation of programs. Recognizing this need, a national review was undertaken to examine the state of the art, gaps, and next steps needed to meet the evaluation needs for new programs, including behavioral and educational initiatives.

This study used interviews, a literature review, and analysis from around the United States to examine technical, research, and policy issues associated with the attribution of savings to programs – including net-to-gross (NTG) ratios and its components, free ridership, spillover, and other issues. The project reviewed results of net-to-gross (and component) estimations from around the country to identify patterns in results for "categories" of programs, and examined best practices in net savings estimation methods used to date for traditional measure-based programs.

This study found considerable variation in NTG methods, coverage, and component results. This project also examined policies used by different states related to this topic, such as whether NTG or its components are used at all, whether "deemed" levels are used, or whether the regulators endorse or include NTG estimates based on primary research. Protocols from several states were reviewed and compared, and the strengths and weaknesses of the approaches were examined.

Beyond reviewing the "state of the art" in traditional attribution work, savings and NTG issues for behavior, education, and training-based programs were also analyzed. For these programs, savings are difficult to measure, and marketplace "chatter" and overlapping programs and deliverers make measurement especially challenging. Some areas of the country are specifically addressing issues related to errors in measurement associated with NTG, and these results are highlighted. Finally, the project examined gaps in existing research, promising techniques for non-measure-based programs, and recommended next steps.

Project Introduction / Context

On behalf of the California Public Utilities Commission (CPUC), this project sought to identify current and improved techniques – and associated policy issues – related to[1]:

- **Gross effects**: Measuring the broad array of impacts caused, or potentially caused, by program interventions – measure-based, market-based, education or other interventions. This includes the measurement of gross energy savings and non-energy impacts.

[1] This paper presents the findings from one of eight white papers on behavior and energy that were funded by the CPUC and managed by the California Institute for Energy and Environment (CIEE). This work does not necessarily represent the views of the CPUC or CIEE or any of its employees. The white papers are available at: http://uc-ciee.org/energyeff/energyeff.html.

- **Net effects attribution**: Identifying the share of those effects – direct and indirect – that can be attributed to the influence of the interventions undertaken – above and beyond what would have occurred without the intervention – either naturally or due to the sway of other market influences or trends.

The overall research examined four key topics in evaluation: gross savings; attribution / free ridership / net to gross (NTG); non-energy benefits; and persistence. This paper focuses on the second of these evaluation topics. The findings from these evaluation efforts play a critical role in an array of applications, from analysis to program design. Given that evaluation results are often used in making program and reward decisions that put significant investment dollars at risk, it becomes prudent to revisit methods and approaches. Further, as programs have evolved, evaluation has become more complex:

- Programs have moved away from "widget"-based programs toward behavioral, education, advertising, and upstream programs that make it harder to "count" impacts.
- There is an increasing number of actors delivering these programs – leading to market "chatter" and increasing difficulty in identifying which among all the deliverers of the energy efficiency "message" are responsible for the change in energy efficiency behaviors, actions, or purchases. The increased chatter in the marketplace creates a situation in which consumers may be influenced by any number of programs by local utilities as well as influences from outside the utility (national programs, neighboring programs, movies / media, etc.).

As a result, attributing or assigning responsibility for changed behaviors and the adoption of energy efficiency measures or services is muddied and challenging.

For this project,[2] SERA[3] reviewed more than 250 conference papers and reports, and reached out to 100 professional researchers for interviews to identify improved techniques (and associated policy issues) for quantifying the share of direct and indirect effects that can be attributed to the influence of program interventions above and beyond what would have occurred without the intervention – either naturally or due to the sway of other market influences or trends. The white paper addresses all four evaluation topics, but this conference paper focuses only on "net-to-gross" and its constituents, free ridership and spillover.[4]

The literature indicates that there are a number of uses to which free ridership, spillover, or NTG ratios are relevant. Free ridership helps to identify superior program designs and helps to identify program exit timing. Spillover helps to assess the performance of education / outreach

[2] The context for this paper (California) relates to, but is not exclusive to, the situation of programs run by utilities with oversight by a public service commission and where shareholder incentives are at stake and depend on the determination of attribution. This review has relevance beyond this situation, but readers in other states may need to make a few adjustments in terminology, etc.

[3] Skumatz Economic Research Associates (SERA) was commissioned by CIEE to conduct this review. The lead author wishes to thank the following for assistance in preparing the white paper: D. Juri Freeman, Dana D'Souza, and Dawn Bement (Skumatz Economic Research Associates), Carol Mulholland, Jamie Drakos, and Natalie Auer (Cadmus Group), and Gregg Eisenberg (Iron Mountain Consulting).

[4] This paper does not discuss "takeback". An example of takeback is when a homeowner turns up the thermostat after more efficient HVAC systems are installed. This review found little recent work on this topic.

/behavioral programs,[5] and it helps to identify program exit timing. Not examining free ridership and spillover *ex post* will make it impossible to distinguish and control for poorly designed / implemented programs, as well as for programs that may have declining performance over time and may have outlived their usefulness, at least in their current incarnation. Some interviewees said 'deemed savings are ridiculous' for this reason.

Definition and Methods – Net To Gross (NTG)

Identifying the "net" effects is a significant element of the assessment of benefits and costs for a program, computations that, in some states, can determine the start, continuation, or termination of a program's funding. Estimating the effects of the program above and beyond what would have happened without the program involves identifying the share of energy-efficient measures installed / purchased that would have been installed / purchased without the program's efforts. Some purchasers would have purchased the measure without the program's incentive or intervention. They are called "free riders" – they received the incentive but didn't need it. Others may hear about the benefits of the energy-efficient equipment and may install it even though they do not directly receive the program's incentives for those installations and are not recorded directly in the program's "count" of installations. This is called "spillover," and there are three types of spillover:

- <u>Inside project spillover</u> occurs, for example, when refrigerators are rebated, and the person receives / installs that equipment, and then later installs an energy-efficient dishwasher.
- <u>Outside project spillover</u> occurs, for example, when a builder receives rebates on one project, but installs similar efficient measures in other homes without rebates.
- <u>Non-participant spillover</u> occurs, for example, when a builder hears about energy efficiency and does not participate or receive any rebates, but decides to install efficient equipment to serve his customers or to keep up with other builders, etc. No incentives were provided for these measures.

Sometimes, the first two examples are referred to as Participant Spillover and the third example as Non-Participant Spillover.

The combination of the "negative" of free ridership and the "positive" of spillover are computed as a "net to gross" (NTG) ratio, and are applied to the "gross" savings to provide an estimate of attributable "net" savings for the program.[6] The NTG ratio only equals free ridership (FR) if spillover (SO) is (or is assumed to be) zero. The NTG, or its components, have been addressed in four main ways, described below. Each approach has pros and cons. We list key strengths and weaknesses of each method based on our literature review and interviews with evaluation professionals.

---

[5] For some of these types of programs, spillover is actually the point of the program, and omitting it ignores important program effects. Ignoring free ridership (in favor of "deemed" NTG figures) allows the continuation of poorly-designed or implemented programs, which wastes ratepayer money.

[6] The literature shows computations of this NTG ratio by adding the factors (1-FR+SO) or by multiplying the factors ((1-FR)*(1+SO)). Both are used in practice.

Deemed (Stipulated) NTG

A NTG ratio is assumed (1, 0.8, 0.7, etc.)[7] that is applied to all programs or all programs of specific types. This is generally negotiated between utilities and regulators or assigned by regulators.

- Advantages: Simple, uniform, and eliminates debate; no risk in program design or performance; inexpensive.
- Disadvantages: Does not recognize actual differences in performance from different programs, designs, or implementations.

NTG Adjusted by Models with Dynamic Baseline

A baseline of growth of adoption of efficient measures is developed, and the gross savings are adjusted by the changes in the baseline for the period.

- Advantages: Can reflect differences in performance for good or poor designs and implementation.
- Disadvantages: Complicated to identify appropriate baseline; data intensive; potentially expensive; introduces more risk to program designers related to program performance; may lead to protracted discussions.

Paired Comparisons NTG

Saturations (or changes in saturations) of equipment can be compared for the program (or "test") group versus a control group. The control group is similar to the test group but does not receive the program. Ideally, pre- and post- measurement is conducted in both test and control groups to allow strong "net" comparisons.

- Advantages: Can reflect differences in performance for good or poor designs and implementation; straightforward concept and reliable evaluation design.
- Disadvantages: Control groups can be difficult to obtain; if imperfect control groups are used, statistical corrections may be subject to protracted discussions.

Survey-Based NTG

A sophisticated battery of questions is asked about whether the participant would have purchased the measures or adopted the behavior without the influence of the program. Those participating despite the program are the free ridership percentage. These are then netted out of the gross savings. Spillover batteries can also be administered to samples of potential spillover groups (participants, non-participants).

- Advantages: Provides an estimate of free ridership and spillover; can explore causes and rationales.

[7] If the NTG is less than zero, then this reflects the likelihood of some free ridership.

- Disadvantages: Responses are self-reported leading to potential bias or recall issues; may be expensive; can be difficult to get good sample of respondents for free ridership; requires well-designed survey instrument which can be long and which affects response rate.

The measurement of spillover involves different issues than the measurement of free ridership. Free ridership emanates from the pool of identified program participants; the effects from spillover are not realized from the participating projects and, in many cases, not even the entities that participated. Identifying who to contact to explore the issue of spillover and associated indirect effects can be daunting.

Our interviews and literature review suggest that a number of states consider free ridership in the calculation of NTG, but do not include spillover in their analyses of program effects, such as California. This analytic asymmetry undervalues energy efficiency by incorporating only subtractions (such as free riders) from gross savings and ignoring potential additions (such as spillover).

Issues and Controversies in NTG Determination

There is considerable – and growing - controversy regarding the use of net to gross, particularly in regulatory proceedings. As noted above, NTG ratios can be used to reduce (incorporating free ridership) or potentially expand (if spillover associated with the program exceeds free ridership) the amount of savings attributable to a program. The concern is that evaluations carefully estimate (gross) savings that were delivered, but then the savings (and, directly, the associated financial incentives to the agency delivering the program) are discounted by a free ridership factor measured by methods that are less "trusted" – in other words, specifically measuring gross savings based on statistical analysis of meter readings/ billing records, compared to measuring free ridership and/or spillover based on self-report surveys of hypothetical decisions and behavior.

Another controversy relates to the fact that only a small minority of free ridership, spillover, or NTG studies report any confidence ranges, or even discussions of uncertainty. Until these issues are addressed, given the financial implications, it is unlikely much additional progress will be made in a more comprehensive treatment of free riders, spillover, or NTG in the regulatory realm. Furthermore, most behavioral and educational programs seem to be treated as indirect programs and not included in regulatory tests. This has a problematic side effect: lack of credits for benefits or savings from these programs results in an under-investment in these efforts. Because of their spillover implications, this puts educational (and potentially behavioral) programs at a disadvantage in portfolio development, designing rewards and incentives, and in resource supply applications.

In some states (e.g., California), these measurements have huge potential financial impacts in which utilities may receive financial awards for running programs and running them well. Based on the interviews and research, the controversy seems to arise from the following main sources:

- The potential for error and uncertainty associated with these measurements, because of difficulties in (1) identifying an accurate baseline; (2) identifying and implementing a control group; or (3) relying on self responses to a survey.

- The expense of high quality analysis – with arguments that the money could be better spent on program design, implementation, incentives, etc.
- Baselines and effects are harder and harder to identify and analyze as programs move up stream, involve different levels of vendors and other actors, and lead to changes in baselines up the chain. In addition, program spillover complicates the identification of a reasonable control or comparison group.
- The difficulty in separating out the effects and influences of different programs within a marketplace (own utility / agency and outside utility / agency), often called "chatter".
- Concerns that using measured NTG or free ridership ratios introduces a great deal (to some, an unacceptable level) of risk or uncertainty into the potential financial performance metrics for the program, which will lead to "same old / same old" programs and reduce innovation in program offerings. [8]

Baselines are a very important part of the problem of measuring NTG, free ridership, and spillover. The calculation of baselines is complicated by several factors, including the difference between prescribed and actual practice, and the challenge of documenting what has not happened. Baselines relate to what would have happened without the program, which is generally understood to mean standard practice. Standard practice might generally be expected to relate to codes and standards, but this is not necessarily the case. In one study (referred to in Mahone 2008), the issue of baseline was found to be quite complex. Mahone (2008) notes that for at least the multifamily sector, none of the buildings were being built to the level of baseline codes – i.e., they were underperforming, so that the actual baseline of standard practice was below the baseline of codes. In this case, NTG would be estimated as greater than "one," since the energy efficiency program improved performance over the standard practice baseline.

Documenting what "would have happened" is the biggest challenge in evaluation (Saxonis 2007). Many interviewees suggested that strong market assessment is needed up-front to provide the maximum amount of baseline information. However, when it comes to the dynamic retail sector, it may be impossible to predict what they would have done without the program (Messenger 2009) – especially if changes occur upstream.[9] More research on standard practice in the field would provide a stronger basis for baselines and provide a sounder basis for determining NTG ratios.

What Precision Is Needed?

Assuming part of the concern about NTG relates to the accuracy of its computations, two questions arise before either including or excluding NTG – and specifically free ridership - across the board. First, how accurate does the NTG need to be for different possible applications, and second, are there computation approaches that provide that – or those varying – degree(s) of accuracy?

---

[8] Innovation is valuable, but agencies will not innovate (cannot justify innovating) in programs unless the risk is reasonably predictable. However, on the other side, regulators must assure that the reward structure doesn't encourage ineffective programs and that funding is spent appropriately and prudently.

[9] For example, some upstream changes may spill over to areas that might otherwise be considered potential control areas. If a manufacturer is induced to change the manufacture or mix of product, and they do so for California which is a big enough market to swing production in general, then the new product lines will become available in the potential control areas and the (important) market effect is then reduced.

The 2003 Nobel-award winning economist, W.J. Granger, noted that evaluations should be designed to the level of 'helping *avoid making wrong decisions (about programs)*'. The evaluation industry also makes a pertinent point that things that are measured tend to improve. Evaluators want to make sure that the following right decisions are made:

1) Assure public dollars are being responsibly spent;
2) Apportion dollars and efforts between alternative strategies; and
3) Help to identify the appropriate time for exit strategies (or program revisions).

This overriding principle has implications relevant to standards for evaluation in energy efficiency. It implies that the level of accuracy applied to evaluation research can be flexible, based on the value (cost) of the possibility of a wrong decision coming out of the particular advisory research. For example, making a decision on going ahead with a program or intervention may allow a much less accurate estimate for input information than a decision about the precise level of shareholder dollars that should be allowed for a particular agency. Thus, it is important to see how NTG results will be used, such as in the following activities:

- **Program planning**: Providing estimates of savings attributable to a program that can be used for program planning purposes (e.g., cost-benefit data).
- **Program marketing and optimization**: Providing quantitative feedback that helps to inform the design, delivery, marketing, or targeting of programs, including revisions to incentives, outreach, exit timing, or other feedback. The evaluation information can be used to understand tradeoffs, benefit-cost analysis, and decision making.
- **Integrated planning, portfolio optimization, and scenario analysis**: Providing savings and other feedback across and between programs that helps optimize program portfolios.
- **Generation alternative**: Providing an estimate of energy savings attributable to a program which may support a decision in deferring new generation.[10]
- **Performance incentives**: Providing estimates of savings attributable to a program that may be used to compute incentives to various agencies in return for efforts in program design, implementation, and delivery.

The degree of accuracy needed in the NTG computation for these various applications are more stringent (higher) if higher dollars are involved, e.g., if shareholder incentives are involved, or if a new power supply is being sought. The accuracy needed to avoid making a wrong decision varies directly with the potential dollars associated with that wrong decision. To illustrate the point, consider the following. "One size fits all" policies are perhaps not the best approach for including or excluding spillover in NTG computations. Ignoring spillover (because we are concerned that the accuracy of the estimates is of concern) for a program for which spillover is a key goal and outcome increases the chances of making a "wrong decision" about that program investment – and eliminates the chance to improve that performance (assuming measurement breeds improvement). Estimating spillover and applying ranges or confidence intervals to the

[10] For example, if a high amount of savings or value is assigned to the program.

values in assessing the program[11] may be preferable to ignoring spillover. On the other hand, ignoring spillover for a low value program or for a program for which spillover is not an integral part may not be a significant concern.

NTG Practices, Results, and Patterns

Several states use the California Standard Practice Manual, or large portions of it, for estimating energy savings, free ridership, non-energy benefits, and benefit-cost regulatory tests, including Oregon, Washington, Idaho, Montana, Wyoming, Utah[12], Iowa, Kansas, Missouri, New Mexico, and Colorado (Hedman, 2009). Several studies specifically examined state and utility practices regarding free ridership and net-to-gross. These studies find that utilities treat the issue of NTG differently. In some cases, there is no regulatory agreement on the estimation of NTG, and they historically treat free ridership only in the calculation of the NTG ratio. The Nevada Power and Sierra Pacific Power collaborative examined free ridership and spillover in 23 states and/or utilities serving states. They found 15 states (69%) did not use free ridership in estimating net savings (Quantec 2008). Other states say NTG is too costly and biased. Massachusetts prefers to have utilities focus on market transformation programs and correct for factors affecting NTG savings in program design. California requires deemed free ridership values in the calculation of the NTG, but excludes spillover. Several other states say estimating NTG is not a priority - they feel free ridership is balanced by spillover and make no further efforts, argue that measurement of free ridership and spillover is unreliable, or say that when they did measure it the value was close to one.

In Illinois, NTG ratios of 0.8 are assumed for low income programs and are lower for appliance efficiency programs (Baker 2008). Washington reportedly doesn't support savings from behavioral changes or NTG allowances or disallowances (Drakos 2009).

In addition to studies reviewing state and regulatory practices or guidelines, this project also examined patterns in NTG values, results, or methods across programs and regions. The authors assembled and reviewed more than 80 evaluation studies from California, New England, and the Midwest that contained estimates of free ridership and/or other elements of NTG. The studies, which covered residential (including low income) and commercial programs, provided estimates for lighting, HVAC, new construction, appliances, motors, and other measures delivered through incentive and non-incentive programs. The studies covered programs dating from 1991 to 2008. The project examined the studies for patterns in methods between areas of the country, and in free ridership and NTG results by sector, measure, or region. Although the studies were assembled as a convenience sample, and not a statistical sample, we found the following general results, methods, and gaps presented in Table 2.

Measure-level NTG performance varied, presumably depending on elements of the underlying program design and possibly due to measurement techniques as well. While these findings are useful, additional, and more comprehensive, work of this type is clearly needed before broad conclusions can be drawn.

[11] Or looking for that threshold value of spillover that "turns the decision" may be another way to address the accuracy issue. If the threshold is outside the estimated range for spillover or outside any credible or feasible range based on the rough estimate, the program decisionmaking is improved.

[12] Utah only allows one year of lost revenues in the Rate Impact Test.

Table 2: NTG Results

	Net To Gross , Free Ridership, Spillover
General results	• Most utilities and regulators exclude NTG or assume values that incorporate only free riders and range from about 0.7 to 1.0 (*ex ante*). *Ex post* results have been measured for many programs; spillover is measured much less often than free ridership (and spillover is more commonly reported in the Northeast than in California). • Most studies rely on self-report surveys using variations in questions incorporating partial free ridership/likelihoods; only a small percent used logit/ranking/discrete choice modeling. • Some studies included both *ex ante* and *ex post* NTG figures for the same program. The *ex post* values were generally 10-20% lower than the *ex ante* values. The most obvious exceptions were some cooking measure programs (*ex post* was about half the *ex ante* value), and some refrigerator programs that reported spillover values greater than 0.5. • Gaps included: Fewer than 10% reported confidence intervals; only a small subset covered NTG for gas savings; and very few studies identified free ridership for electricity savings; most considered only kWh effects.
Variations by measure type, program type or region	• Clear patterns for free ridership, spillover, or NTG results by measures, program types, and regions have not been demonstrated to date. The assumption is that variations in specific program design and measure eligibility definitions are important to results. NTG results in the literature are also affected by whether or not spillover is included in the assessment. • *Ex-post* free ridership clustered around 0.1-0.3 but ranged as high as 0.5 to 0.7 for some commercial HVAC / motors and refrigerator initiatives. *Ex-post* NTG clustered around 0.7-1.0, but dipped as low as 0.3 and as high as 1.3. The lowest free ridership was low income programs (as low as 0.03). • NTG for whole homes and home retrofits tended to be high (0.85 to 0.95), but ranged from 0.5 to more than 1.0. • Net realization rates were provided for about one-third of the programs, and the values averaged about 0.7 to 1.0. A number of values exceeded 1.0, including commercial HVAC rebate programs (1.07) and refrigerator rebate programs (1.15). Several programs showed net realization rates between 0.3 and 0.5 including several CFL programs, some refrigerator programs, some gas cooktop rebate programs, and some energy management system initiatives.
Variations for behavioral vs. measure-based programs	• Studies addressing NTG, free ridership, or spillover estimates associated with strictly behavioral programs were not found, and if available, are probably too few in number to lead to overarching conclusions or patterns.

Emerging Methods and Recommendations

Based on this project's analysis of the literature and interviews with evaluation professionals, the following findings and recommendations regarding NTG determination are presented:

- **Incorporate the refinements made in standard practices**. Historically, fairly simplistic measurement methods have been used to estimate free ridership. The computations have been based on self-reports. Sources of error with this method stem from faulty recall, bias toward claiming the program was not influential or influential, and from bias introduced in the form of hypothetical questions.

  The literature review noted improvements in self-report methodology including questions to distinguish "partial" free ridership. Later, studies combined partial free ridership with a review of "influencing factors" or "corroborating questions" which were used to adjust free ridership reports based on the combined evidence from the other questions. For example, the questions might ask about the importance of the rebate in decision-making, whether the purchase was moved forward two years or more, whether they were already aware of the measures, and similar questions, and used these responses to validate or adjust responses to direct free ridership responses (Skumatz, Woods, and Violette 2004).

Other approaches have established multiple criteria for free ridership. In one study, free riders had to meet four criteria: aware of the measure before the program, intending to purchase before the program, aware of where to purchase the measure, and willing to pay full price. If the four conditions were met, the household or business was classified as a free rider. In another example, the Energy Trust of Oregon conducts long-term tracking on a number of programs –they assess the market, identify program influencers, and conduct in-depth research in order to determine how much of the gross savings to claim for the programs (Gordon 2008).

- **Recognize we may need to allow "credit-splitting or credit-sharing".** One key refinement may be the recognition that we may not be able to attribute "causality" to one program or intervention, but may need to consider splitting the credit. The issue of "chatter in the marketplace" is a concern, but this is also an issue for technology / measure / economic based programs as well as education / outreach programs. However, the industry has been more willing to apply causality to technology measures because we can see something put an implementation or desired decision "over the top" more clearly. It is important to understand what is happening in the market and if a 0/1 litmus test is required for causality, it is unlikely to be "proved" as attributable to a particular program or element (Messenger 2008). Recent attitudinal research from the Energy Center of Wisconsin confirmed that people get energy-saving information from multiple sources and concluded that… "it may take a village to raise a behavioral kilowatt-hour sometimes" (Bensch 2009). This may make it hard to attribute the kilowatt-hour to one specific influencer, but that doesn't make the kilowatt-hour less real or mean that the program had zero effect. The solution may be to acknowledge shares of the kilowatt-hour to multiple contributing factors (for behavioral and technology measures) and share the credit (Bensch 2009). And sharing the credit may be the right answer, as people may only pay attention if it is a 'whole choir singing the "save energy" song' (Bensch 2009). Sulyma (2009) argues that it is more than time to move beyond only "one" plausible explanation for impacts, and that probabilistic methods should be used to address this attribution issue.

- **Require random assignment for participants and non-participants for as many program types as feasible**. The experimental design approach has been well known for decades, with random assignment of eligible participants assigned to treatment and non-treatment groups. This helps address the baseline issue in a credible way. However, to implement this option would require the regulators, utilities, or agencies to "bite the bullet" in terms of the political fallout from those that want to participate but are put into the "no treatment" bucket. Or future participants could be put "on hold" – they could be used as a control group in the short term, but can participate in the program at a later time. This approach may be especially important for outreach and behavioral programs. Train (2009) suggests pairing this with a discrete choice model to predict behavior.

- Many interviewees also agreed that well-designed randomized control and treatment groups are well-suited to impact evaluation (and attribution) for behavioral programs; however, the evaluators and regulators have not developed the kind of faith in them that they have in other programs. The use of these approaches with appropriate modeling (including mixed logit, discrete choice, etc.) shows promise (Ridge et. al. 2009, Train 2009). There is also concern that these random techniques may become more complicated, as controlling for the many influences is complex (including spillover), making a battery of questions important to the analysis (Messenger 2008, Cooney 2008, Train 2009). However, these kinds of tools – well-accepted in other social fields and with history in energy - apply well to energy-based behavioral programs. More evaluations of behavioral programs, and greater widespread cataloguing of the results (along with time), may be necessary to gain greater acceptance by regulators.

- **Consider survey designs that introduce a real-time data collection element.** There have been several instances in which utilities have introduced NTG-surveys as part of the program participation documents and gather early feedback – near the point of actual decision-making – on the program's influence in adopting the measures (Gordon and Skumatz 2007). This provides several benefits: increases return rate / sample size (and eliminates the problem of finding participants after they have moved or after years of delay); provides on-going data and allows evaluation at virtually any point after the program is implemented to support on-going refinement of programs; significantly reduces the cost of surveying and evaluation; provides more accurate data if the point of feedback is close to decision-making (recall may be improved); and helps to sort out which programs had what degree of influence. This may be suited to education and behavioral programs as well as "widget" programs, but needs testing, as the approach has not been widely applied.[13]

- **Consider discrete choice modeling approaches.** These approaches introduce explanatory variables that help to address issues of imperfect control groups, unobserved factors, etc. to allow improved estimates of attributable impacts. A discrete choice model predicts a decision made by an individual (purchase a measure, adopt a behavior, participate in a program) as a function of a number of variables, including demographic, attitudinal, economic, programmatic, and other factors. The model can be used to estimate the total number of eligible households, businesses, etc. that change their behavior in response to a program or action. The model can also be used to derive elasticities, i.e., the percent change in participation or behavior change in response to a given change in any particular (program design, demographic, or other) variable.

- **Consider compromise or "hybrid" approaches for fiscal-related applications.** A case might be made that the most "accurate" metric is pure *ex-post* measurement especially when those estimates are used for planning and reward purposes. If the main "rub" arises when NTG elements are part of the computations of financial reward or program approval, there are several possible options for the short term (until a "grander" solution is identified). <u>Short-term deemed values</u> (1-2 years of a new program that differs from

[13] It has been suggested that the smart grid or technologies might enhance the opportunity for real time collection of some important data elements.

traditional offerings) could be identified, allowing time for development and refinement of new, creative programs without punishing fiscal consequences. The program could be dropped if performance doesn't meet the offerer's expectations, and the method avoids an innovation penalty. True-up at some point is necessary to assure that the field learns about the performance of different types of programs and to assure that ineffective programs are not rewarded indefinitely. Deemed spillover values may be especially needed for programs targeted at education. Long-term deemed values could be allowed for well-known program types based on measured NTG from programs around the nation, where program performance is checked every 3 years, and where programs are penalized that perform more poorly than the norm, or require program comparisons against "best practices" periodically (every 3 or so years). Again, periodic true-up is needed. Another "tweak" to test to encourage innovation might be allowing differential rewards: upside incentives could potentially be larger than downside penalties for innovative programs. For some large, important, or innovative programs, negotiations for a priori values might be used.[14] Fiscal incentives must encourage (or at least not penalize) innovation, or only mediocre or "same old" programs will be offered – and they will be offered well past when they should be out of the market.

Reliable measurement methods are available that suit many program types, but more work remains, including research needs in the following areas: [15]

- Greater application of enhanced NTG, free ridership, and spillover methods incorporating partial (and/or deferred) free ridership and corroborating information.
- Greater use of experimental design (including random assignment for participants and non-participants) for as many program types as feasible.
- Comprehensive market assessment work for baseline support, on non-participant spillover, and modeling of decision-making. This is particularly important for many training, education, and behavioral programs.
- Data collection approaches that introduce a real-time data collection element piggybacking on program handouts / materials / forms and to allow periodic reviews of performance in time to refine programs.
- Discrete choice and other modeling methods, and statistical techniques to help address issues of imperfect control groups, unobserved factors, etc., to allow for improved estimates of attributable impacts.
- Accumulation of results on elements of NTG in a database and continuously updated with new research and evaluations, so comparisons and tracking are facilitated.

[14] This may cover programs such as those offered to only a very few large businesses (industrial, etc.), for example. This is suggested by the method NYSERDA is implementing for measuring NTG from their custom program that has very few participants (Cook 2008).
[15] And, as recognized by one of the paper's reviewers, these "methods-type recommendations" do not touch on issues such as who does the evaluation and the ability to share results for real-time program improvement.

Summary

Estimating the effects of the program above and beyond what would have happened without the program involves a relatively complicated step – identifying the share of energy-efficient measures installed / purchased that would have been installed / purchased without the program's efforts. Traditional elements include free ridership and spillover, combined into a NTG ratio. Spillover is more complicated than free ridership to measure, and as a consequence, a number of utilities that include free ridership never estimate spillover. However, given that many of the benefits from outreach and educational programs – and from a host of "non-widget-based programs – are realized from "spreading the word" (and the behaviors that follow), developing and using reliable and trusted methods that incorporate free ridership in program computations is a priority. These results are needed for applications including program design / assessment / refinement / portfolio development, program exit timing, and incentives.

Reasonable reliability is needed to provide useful information. To provide the best chance for optimal programs, several things are needed. NTG, free ridership and spillover estimates that are as reliable and precise as needed for the particular use – with greater precision needed for the calculation of program or portfolio incentives vs. quasi-quantitative / qualitative uses. NTG, free ridership and spillover estimates that provide replicable results and are based on credible, defensible estimation methods suited to the accuracy needed are a critical step in getting NTG results included in design and evaluation. Methods suited to different levels of accuracy for estimates of NTG, free ridership and spillover at reasonable cost levels would help optimize expenditures where they are most needed, and balance the tradeoffs of program funds vs. evaluation expenditures. Similarly, there should be flexibility in the application of NTG, free ridership and spillover results depending on type of program (whether programs are new / innovative / pilot; "same-old-same-old"; cookie cutter; custom; information-based; etc.).

Finally, it is critical that the application of NTG results is conducted in ways that avoid discouraging the development of new and creative and potentially effective programs. NTG should be applied in ways that properly assess program performance, but makes the risk of fiscal investment in (especially, new and innovative) programs manageable and reasonably predictable.

Current incentive structures, calculating attribution among actors, and the difficulty in identifying "participants" in new programs are discouraging innovation and leading researchers to consider discarding NTG analyses as a tool in energy efficiency evaluation. This is throwing the baby out with the bathwater. Instead, more widespread application of some of the approaches summarized in this paper can preserve the positives but not be hampered by the negatives of traditional NTG assessment. These evaluations are needed to "help avoid making a wrong decision…" with the public's money. To do this effectively, we need good methods, and we need to make sure the results are fed back into programs to be used in decision-making.

References[16]

Baker, David S., 2008. Illinois Department of Commerce and Economic Opportunity, Energy Division. Interview with the author, November 20, 2008.

Bensch, Ingo, 3/31/09. Energy Center of Wisconsin, WI, Personal Communication with the Author.

Cooney, Kevin. 7/31/08. Summit Blue, Boulder, CO, Personal Communication with the Author.

Drakos, Jamie, 3/31/09. Cadmus Group, Portland, OR, Personal Communication with the Author.

Gordon, Fred, 7/25/08. Oregon Trust, Portland, OR, Personal Communication with the Author.

Hedman, Brian. 3/31/09. Cadmus Group Portland, OR, Personal Communication with the Author.

Mahone, Douglas. 2008. Email from Douglas Mahone to Robert Kasman (PG&E), June 12, 2008, provided to author.

Messenger, Michael. 7/29/08 and 4/3/09. Itron, Sacramento, CA, Personal Communication with the Author.

Quantec, Scott Dimetrosky. 2008. "**Assessment of Energy and Capacity Savings Potential in Iow**a", Prepared for the Iowa Utility Association, February 15, 2008.

Ridge, Richard, Phillipus Willems, Jennifer Fagan, and Katherine Randazzo. 2009. "**The Origins of the Misunderstood and Occasionally Maligned Self-Report Approach to Estimating the Net-To-Gross Ratio**", *Proceedings of the IEPEC Conference*.

Saxonis, William. 2007. "**Free Ridership and Spillover: A Regulatory Dilemma**", *Proceedings of the IEPEC Conference*.

Gordon, Susie, and Lisa A. Skumatz, 2007, "**Integrated, Real Time (IRT), On-Going Data Collection For Evaluation – Benefits And Comparative Results** (Gordon & Skumatz, 4323), Procee*dings for the European Council for an Energy Efficient Economy (ECEEE)*, France, June.

Skumatz, Lisa A., 2009. "**Lessons Learned and Next Steps in Energy Efficiency Measurement and Attribution: Energy Savings, Net to Gross, Non-Energy Benefits, and Persistence of Energy Efficiency Behavior**", prepared for CIEE, December. Available at: http://uc-ciee.org/energyeff/energyeff.html.

Skumatz, Lisa, Dan Violette, and Rose A. Woods, 2004. "**Successful Techniques for Identifying, Measuring, and Attributing Casualty in Efficiency and Transformation Programs**." *Proceedings of ACEEE Conference*, Asilomar, CA.

[16] The long list of references underlying this project is cited in Skumatz 2009, the full report from which this article is excerpted.

Sulyma, Iris M., Power Smart, BC Hydro, Vancouver, Canada, Personal Communication with the Author, 4/28/09.

Train, Kenneth, UC Berkeley and N/E/R/A, CA, Personal Communication with the Author. 10/6/09.

Maximizing Societal Uptake of Energy Efficiency in the New Millennium: Time for Net-to-Gross to Get Out of the Way?

Rafael Friedmann, Pacific Gas & Electric Co., San Francisco, CA[1]

ABSTRACT

Humans are running out of time to reduce global warming gas emissions to avoid horrendous socio-political and environmental consequences. Reducing global warming effects may require an 80% decrease in greenhouse-gas emissions by the year 2050. This will require a sharp reduction in the use of fossil-fuels our modern civilization is based on. Widespread uptake of energy efficiency and conservation are the best options available to mitigate global climate change and provide time for developing more sustainable and renewable energy supply sources.

California's thirty-year promotion of energy efficiency provides valuable experience and an institutional and market infrastructure to broaden and deepen customer uptake of energy conservation and efficiency. California policymakers, entrepreneurs, and public show a heightened interest in energy efficiency.

To accelerate uptake of energy efficiency will require California to update evaluation policies and protocols for overseeing the almost one billion dollar per year publicly funded energy efficiency endeavor. Current evaluation is more focused on regulators need of attributing energy savings to specific programs and less so on optimizing interventions. Programs and evaluations are focusing mostly on energy efficient measures (EEMs) that get incentives.

This paper calls both evaluators and policy-makers overseeing energy efficiency portfolios to acknowledge the need for, and move to develop alternate evaluation policies, protocols and methods that will ensure publicly funded energy efficiency efforts are cost-effective, while also being supportive of non-traditional, more economical and deep market transforming interventions. These new evaluation policies and protocols should still ensure continued public oversight. The paper draws upon the California context to show how the Net-to-Gross ratio as currently applied inhibits new, market transforming energy efficiency interventions. Paper ends providing some initial thoughts on how to improve this situation.

Background

Society has long understood the crucial nature of energy to transform the natural world to get goods and services. This initially led to social support for the creation of an increasingly larger and complex energy supply system. With time, this evolution has been accompanied with an understanding that there are social costs that are not fully internalized by private markets and thus, suboptimal investments and developments occur in the energy sector.

This awareness of the suboptimal investment has led to a willingness to collect and use public funds to foster more socially optimal development of the energy sector. Energy efficiency programs funded with public funds is a good example. This public energy efficiency expense comes from a generalized understanding that the free market will not adopt higher efficiency on its own, nor will it

[1] Any opinions expressed explicitly or implicitly are those of the author and do not necessarily represent those of Pacific Gas and Electric Company.

internalize the socio-politic or economic benefits and costs of the variety of energy infrastructure it has developed.

Public good funds for energy efficiency seek to maximize public benefits at minimum cost. Figuring out how to best use these public funds is complicated by a myriad of factors including risks, uncertainty, investment in short versus longer term opportunities, and various intervention strategies that seek to overcome perceived barriers to energy efficiency adoption.

In California and elsewhere (NW, NE and mid-west USA), publicly funded energy efficiency has a long history. In California, it is over 30 years old and has encompassed a variety of intervention strategies and administrative structures. Since 1996, these interventions have been mostly administered and run by the four investor-owned-utilities (IOUs), using public funds collected in rates. Regulatory oversight by the California Public Utilities Commission (CPUC) has sought to ensure IOU expenses optimize the use of these public funds.

As part of the determination of optimal use of these public funds, evaluation protocols have been established and significant evaluation efforts have been done to measure savings from these program interventions (check www.calmac.org for evaluation studies, and TeckMarket Works 2004, 2006). To ensure that funds are used in the best fashion possible, evaluation has focused on determining both gross savings and net savings by energy-efficiency-measures (EEMs) and/or programs. Gross energy savings encompass the totality of energy saved by programs or portfolios. Net savings refer to the energy saved that can be attributed to the programs beyond what would have happened anyways or "baseline". Gross energy savings are adjusted using a "Net-to-Gross" (NTG) ratio which in principle should include both an upwards adjustment for savings obtained beyond the program (spillover) and a downward adjustment for savings which would have happened anyways absent the program (free-riders).

California's four main investor-owned-utilities are currently administering a three-year, 2.1 Billion dollar publicly funded energy efficiency effort, under oversight and policy guidance by the California Public Utilities Commission (CPUC). The goals for this three year effort are to save 5.1 TWh, 2.2 GW and 111 MM Therms of natural gas. These goals are part of a longer-term effort that sought to save during 2004-2012 about 23 TWh, 4.9 GW, and 444 MM Therms.

Given the most recent findings of the Intergovernmental Panel on Climate Change, there is an interest in trying to save even more energy. Indeed, California Assembly Bill 32 calls for California to return to 1990 greenhouse-gas emissions levels by the year 2020 and the Governor issued an executive order that seeks to cut emissions by 80% by 2050.

For California to reach these goals, will require doing more transformative energy efficiency by tapping and engaging markets both broader and deeper than those to date. Broader in the sense that everybody will need to engage in energy efficiency. Deeper in that everyone will need to do more than what they have done. We will need full adoption of energy efficient lighting, premium motors, systems focused energy efficiency rather than individual energy efficiency measures (EEMs), as well as capturing process engineering enhancements, integration with renewable energy technologies, etc.

The current energy efficiency evaluation protocols are too focused on attribution of savings; counting only direct program participants energy saving actions corrected for free ridership. This focus promotes portfolios based on EEMs that are easy to measure and verify; undervaluing resources spent on programs that have longer lead times and/or high spillover effects. Although the current evaluation focus addresses the CPUC's need to minimize crediting of free rider savings, it also affects and impacts addressing other important societal goals, such as maximizing net energy savings and GHG emissions reductions.

The remainder of this paper explores how California's evaluation protocols, especially with regards to NTG may be inadvertently constraining the variety of interventions and resulting in reduced energy savings yields. The paper begins by drawing on the diffusion of innovation concept (Rogers 1995) to describe barriers faced by customers seeking to adopt more energy efficient technology. The discussion focuses on how the NTG can vary at the various stages of technological market adoption. This provides insights that are then exemplified with three possible new interventions that could lead to large energy savings with minimal public goods funding but that are constrained by the current evaluation protocols from happening. The paper ends by discussing how these protocols make broader and deeper efforts riskier given the high savings targets/goals; reducing energy efficiency administrators and implementers shy away from broader and deeper, higher spillover, market transforming interventions.

Current context requires and allows for new, more cost-effective energy-efficiency adoption interventions

At least two major issues with past evolution of the energy sector have recently heightened interest in tapping all cost-effective energy efficiency options first: Global Warming and Resource Adequacy. Global warming requires a significant reduction of Greenhouse Gas (GHG) emissions (some say up to 80% by 2050) to avoid most of the expected socio-politico-environmental impacts identified in the most recent IPCC reports. The frailty of the current energy supply system has become especially obvious in the wake of the California electricity crisis of 2000-2001, the large northeastern blackout of 2005, and Hurricane Katrina. Energy efficiency showed its worth to society during and after the California crisis, saving up to 14% of peak demand and 7% of electricity use in 2001; saving California from experiencing ongoing blackouts that summer. Energy efficiency is also recognized as the most cost-effective option for reducing GHG emissions, with a variety of energy saving measures costing less than 3 ¢/kWh and 1.2 $/MMBtu (Prindle et al. 2007). Energy efficiency and conservation reduces pollution and also gives time to develop better supply alternatives, especially renewable energy technologies and services, where technical breakthroughs and more importantly, market maturity is needed for full cost-effective deployment.

The current context is very receptive to energy-efficiency. There is increased public and private interest in energy efficiency. Corporations are seeking to enhance profits and their image among consumers and shareholders. GE's Ecomagination division had revenues of 17 Billion dollars in 2006; Walmart has established a group focused on sustainability and advertised its intent to sell 100 million compact fluorescent lamps (CFLs) in 2007; Home Depot gave away 1 million of these CFLs this past Earth Day; IBM has announced a 1 Billion dollar program to help its client data centers become more energy efficiency; and among automakers, Toyota and Honda higher energy efficient cars have fueled these two companies profitability and increasing market share over there less energy-efficient-focused competitors. Venture and pension fund capital managers are also increasing its interest and "seeding" new renewable energy and energy efficient technologies. The media is not far behind, with stories about global warming, energy efficiency, and renewable energy technologies showing up regularly in both local and national print and video media, as well as long-term stalwarts of "free markets" like the Economist (Sep 2006). Customer interest in these topics and eagerness to "do what's right" is an at all time high. We've even seen customers banding together to stop TXU's Board's recent interest in building eight new coal-powered power plants.

Albeit the increased interest in energy efficiency, studies still show that not all cost-effective EE is being adopted by customers, nor is ongoing development of products and services fully obtainable from business-as-usual (D Goldstein 2007; Itron 2006). This is the reasoning behind the ongoing support of energy efficiency promotion with public funds.

The question that arises is whether these funds are being spent in the most cost-effective and energy saving manner. It is also important to examine how current evaluation protocols and policies may be impacting what energy efficiency interventions are undertaken. This paper only examines the impact of NTG's policies, leaving for another discussion other areas that require review and possible revamping.

Let us examine what precludes customers from adopting all cost-effective energy efficiency and how NTG and its determination are not straightforward. Current California protocols regarding application of NTG in essence, by only counting free-riders, ignore non-energy benefits, which typically are the key leverage points to get customers to adopt more efficient services or products. New evaluation protocols with a broader perspective on overall societal benefits could increase research on customers and market actors resource efficiency motivators; providing insights for the development of more cost-effective public interventions.

Barriers to Capturing Energy-Efficiency Opportunities

The objective of a publicly funded energy-efficiency portfolio is to accelerate adoption of efficient energy use practices and technologies across a variety of customers served. Theoretically, successful public interventions spur along the maturation of energy efficiency markets so that these reach a "tipping point" where public interventions are barely needed. To succeed, the portfolio offerings need to take into account this varied mix of customers and their needs, continuously adapting to the changing context in which they are implemented. This requires a thorough understanding of customers needs to enable program offerings to align and produce optimal results. In California, even with over a quarter century of publicly funded energy-efficiency promoting programs, the energy efficiency market is still immature. Yet a new, energy-efficiency enabling context is growing; providing new opportunities for public resources to leverage private efforts to hasten market maturity. The key therefore is to clarify where markets are, what are the key barriers to further development of the market, and how to best tap into public and private resources to hasten tipping points for energy efficiency adoptions when these are possible, while still supporting the needs of less mature market segments.

This section briefly discusses key barriers faced by customers seeking to adopt energy efficiency. It also discusses how the barriers and context customers face change as an innovative product disseminates into the marketplace. This sets the stage for understanding why the CPUC's focus on attribution and rules regarding application of NTG lead to suboptimal results.

Energy-efficiency proponents talk about at least four major barriers that preclude customers (and society) from adopting all the cost-effective energy efficiency options (see Friedmann & James 2005; Friedmann 2006). These barriers are:

- Awareness. Where customers lack information on the options available, and/or their benefits.
- Availability. Manufacturers do not make or market more efficient measures as they do not expect to have a market for these (usually invisible) enhancements to their products.
- Accessibility. Distributors and retailers may not stock or aggressively display the EEMs making it hard for customers to find the more efficient products and services they seek.
- Affordability. Usually, EEMs are more expensive than the widgets they seek to replace, partly because of better quality components, partly because of their less developed and less competitive markets, with higher transaction costs to get these to market.

In order to address the barriers mentioned above, a public energy efficiency portfolio will include research, development and demonstration (RD&D) efforts, information and education components, programs to persuade customers to adopt more energy efficiency widgets and practices, and codes and standards to enhance the efficiency of buildings and equipment. The resources devoted to each of these public interventions will be determined by the market maturity context in which the decisions are made. They will change over time, across customer segments, and draw upon appropriate programmatic and project-level interventions as needed.

The programmatic and project-level interventions used need to address in more efficient and cost appropriate methods the changing needs of the market they seek to influence. Thus, the energy efficiency portfolio will be ever changing, reaching into new areas for further energy-efficiency, and contracting in others, where savings have been tapped out, or where markets have evolved and do not require further public support to continue to evolve.

The evolution of the dissemination of an energy efficient technology can be theorized to follow an S-shaped curve with four major market stages (immature, maturing, mature, and new EE technology markets) as shown in Figure 1 (Rogers 1995). An effective portfolio will optimize the mix of offerings to best address the challenges being faced by each of these four stages of market evolution to align benefits with societal needs. The intent is to match portfolio offerings to market needs, and to do so at crucial leverage points. Some of these efforts will be upstream, midstream or downstream, and/or geographically defined.

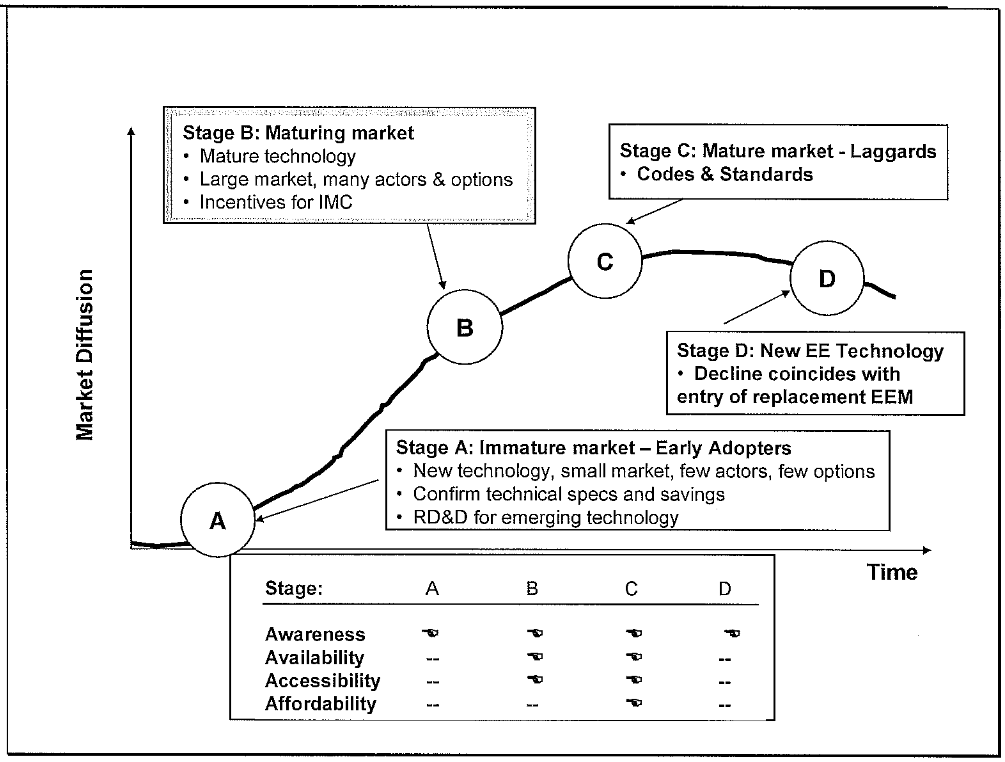


Figure 1. Market Evolution Curve for an EEM or EE Practice and Barriers Faced at Each Stage

There are important linkages among these four stages of market evolution. Stage A describes the early stages of a new technology or practice. Typical interventions for this stage focus on research, development and demonstration (RD&D). Decisions on what technologies or practices to include in the portfolio in Stage A depend on the remaining significant opportunities for energy savings. These depend in part on the previous maturation of other energy-efficiency measures addressing the more important customer energy end-uses. Indeed, Stage A and Stage D are interlinked, as the new technologies or practices being developed in Stage A begin to reduce the saturation in the market of the technology or practice that was previously being promoted by market interventions in Stages B, C and D. In Stage B, a technology or practice has become better known, is more available, accessible, yet still most likely, significantly more expensive than the less efficient technology or practice it seeks to supplant. Stage B is where most portfolio resources are typically spent currently, in the form of audits and incentive programs to help reduce the incremental costs of efficient measure's adoption. In Stage C, most of the customers have adopted the more efficient technology or practice, but some significant portion of the customers is unlikely to ever adopt it. In Stage C standards and codes are typically the intervention of choice to ensure that all customers adopt the more efficient technology given its significant societal benefits. By Stage C, the efficiency interventions administrator needs to be identifying and beginning to develop the next generation of technologies and/or practices to introduce (and start their own Stage A). This is reflected in Stage D, where the saturation of the current efficient technology is being impacted by the growing market presence of the next generation, even more efficient technology already in its own Stage A or perhaps even Stage B.

Eventually, as the private energy efficiency market grows and matures, one would hope that public support would center on Stages A and C, leaving private market actors to address most of Stage B. In this ideal theoretical construct, public funds would be used where most effective (namely where the private sector would not invest adequately due to the public good nature of that market), and be supplemented largely by private market actors positioning themselves to serve the maturing market customer in Stage B. Indeed, public resources would be used to guide and also provide credibility to private actors' best energy efficiency offerings in Stage B. This public-private market segmentation has only begun to occur in a few select situations, for example, with CFLs in homes and T-8 fluorescent bulbs in businesses. Even in these two cases, private market actors still look for various types of support from publicly funded programs. These public programs also are involved in coming up with the next generation of lighting products: LED and T-5 fluorescent lighting.

NTG and Maturing Markets for Energy Efficiency

Drawing from the diffusion of innovation for energy efficiency products and services curve, and the barriers inherent to each stage of market evolution, we examine here what factors affect the Net-to-Gross (NTG) ratio for any public interventions and the likely resulting value for NTG (see Table 1).

NTG at each stage of dissemination of innovation is different, as the key four barriers impact varies. NTG may be high in early adopter—because there is very low availability, accessibility for EEMs in Stage A. Although affordability and awareness also very low among the general population, they are actually high among the early adopter crowd. Thus, what the overall NTG—when defined as "what would have done without the program" depends on whether early adopters would have indeed been aware of the technology and been willing to spend more and seek it out to overcome the availability and accessibility barriers. Worse, should someone just focus on the early adopter participant customer's NTG it is likely the NTG would be quite low, and possibly lead to a decision to discontinue supporting the evolution of its' market. In this situation, spillover happens over time. Although the early adopters' NTG is low, through their actions and public support of market actors becoming engaged in the EEM, you are moving this technology to Stage B. Thus, just focusing on the early NTG, could lead to a decision to stop public support of the incipient EEM market, long before it is ready for uptake by the majority of customers and at least delaying capturing this technology's savings.

Table 1. NTG for Evolving Markets of EE Technologies

Market Stage	Participant Characteristics	Net-to-Gross Issues Of Participants
A. Immature	Early adopters. Embrace new technologies quickly	Awareness, affordability, accessibility, availability all low—imply high NTG; yet propensity to adopt is high among early adopters, possibly resulting in low NTG
B. Maturing	Majority of market. Require information, incentives, and other support to adopt efficient products	Relatively high NTG as these customers not "primed" to adopt new technologies and require information to be made aware, market support via upstream/midstream programs to enhance availability and accessibility, and incentives to improve affordability
C. Mature	Reticent/laggards. Lag at adopting new technologies or practices	Very high NTG as these customers very reticent to adopt EEMs. Indeed, C&S are used to force adoption, and even then, compliance with them can be very spotty
D. Decline	Back to early-adopters.	NTG indeterminate, depending on market barrier being faced for new, replacement EEM

In Stage B, all four barriers of awareness, availability, accessibility and affordability are being lowered. At this stage, the NTG for early adopters is low given the very high free-ridership; but for the mainstream customer, NTG is probably quite high initially and then, starts to decline as the market for the technology continues to mature.

In Stage C, all four barriers have been mostly overcome. The NTG is very low for both early adopters and mainstream customers, but very high for the late/never adopter. Adoption by the late adopters is obtained through mandatory energy efficient Codes and Standards. Yet compliance with the Codes or Standards remains a problem. NTG for these laggard customers is very high, but very low for all other customers.

We have seen that NTG is very dependent on the stage of market development for the energy efficient product being considered. Also, the rules on how NTG is applied can heavily influence the portfolio of energy saving strategies pursued. The market context within which we are seeking to enhance customer adoption of a particular energy efficiency product is also important. After 30 years of efforts and with the increased public and private interest in GHG, fossil fuel availability and socio-political implications of our dependence on them, it is becoming very hard to accurately estimate a NTG for a specific program intervention or EEM. Given the current context and energy savings goals under which California's energy efficiency programs are operating, it seems that a revision of the policies and their focus on NTG is needed. How these two aspects come together is discussed next.

NTG and Big, Bold Efficiency Interventions

In the search for new options to continue to garner energy savings and their accompanying socio-economic-environmental benefits to society, the question of how NTG (among other evaluation protocols) affects the possibility of carrying out effective new big and bold ventures comes up. We briefly describe three possible interventions being considered for the PG&E service territory and explore how current rules regarding NTG increase the risk of meeting savings goals making these interventions less interesting for the utility to pursue.

CFLs – Getting deeper and broader adoption by customers

About 31% of California homes have yet to install a single CFL. Of the remaining 69% of homes who have installed CFLs, only about 17% have installed 15 or more CFLs and can be assumed to have fully saturated their home lighting with CFLs (RLW 2005). Therefore, probably about half or more of the residential lighting is still using inefficient incandescent lights. According to the latest energy efficiency potential study (Itron et al. 2006), full saturation of CFLs would imply slightly over 100 million installed CFLs in PG&E serviced homes. The same study estimated at 53 million CFLs the maximum achievable saturation between 2004-2016. PG&E is seeking to accelerate adoption of CFLs via an upstream/midstream market program that offers about $2/CFL to manufacturers and distributors and retailers. This allows retailers to sell the CFLs for $1 each. Sales volumes have been increasing rapidly with up to 25 million expected in 2007, up from almost 7 million in 2006 and 4 million in 2005. Should this growth continue, PG&E homes will be close to CFL saturation in 2 to 3 years. The program has very low administrative costs by offering the incentives to manufacturers, distributors and retailers instead of customers. Yet this makes determining NTG very difficult, as participant contact information is unavailable. Instead success could be measured in terms of product availability, accessibility, affordability, and awareness. A survey of households (given that about 69% have CFLs) would still be hard pressed to get a reliable value for free-ridership given the multitude of energy efficiency messaging and promotions going on in the marketplace and that PG&E's incentive is almost invisible to the customer. Current evaluation protocols do not allow credit for any spillover, further reducing the per-protocols, official cost-effectiveness of the CFL upstream program. The program strategy is successful but can easily result in mistakenly high free ridership estimates. If the free ridership estimates come out too high, PG&E may decide to end this program (which also helps promote higher quality CFLs that have more of the characteristics customers want and that usually have led to rejection of CFLs in the past), before the CFL market is fully tapped out, leaving significant energy savings untapped.

Large Commercial Office Buildings

PG&E is currently offering a variety of products and services to large commercial office buildings. These include audits, retro-commissioning and commissioning, design-assistance, incentives for more efficient equipment, training on both, opportunities and enhanced operations and maintenance, etc. Customer outreach is mostly via PG&E Assigned Service Representatives (ASRs). The idea is that large office building managers can avail themselves of a variety of energy efficiency services to meet their needs through just one point-of-contact. Research is being conducted to allow for an even better focused program to meet this market segment needs. The idea is to characterize the large office buildings in PG&E territory by ownership and management set-up. PG&E will then reach out to these building owners and operators at the most appropriate levels of decision-making on energy-related investments, with appropriate messaging and utilizing the most appropriate PG&E staff level. This will imply establishing long-term relationships at various levels of both PG&E and the large office building manager or owner that will enhance uptake by the customers. Rather than focusing most of the effort on incentives, it is quite likely that efforts will be required at non-rebated aspects of the business decision. Tracking and determining the ultimate influence on energy savings of this variety of interventions among a variety of decision-makers (e.g., across the engineering or capital investments leadership within these organizations) over a long period of time, will be very difficult, and figuring out a free-ridership ratio even more difficult. How would one apportion such a free-ridership if say 8 of 9 decision makers were totally keen on adopting the technology (i.e., free riders) yet the 9th and final decision maker (or even the first one on the decision-tree) only agreed to the enhancement thanks to the intervention of PG&E? How will a NTG based only on participant free-ridership underestimate the energy savings from spillover, within the organization and variety of decision-makers involved and their impact on their peer groups and over time? How interested will PG&E be in pursuing this business model if there is a high level of risk on what savings will be ultimately apportioned to its efforts, partly because of current protocols governing NTG and the difficulty of estimating it?

Data Centers—Brave New World

PG&E estimates data center load growth at between 400 and 500 MW. A variety of hardware and software options are now available that can cost-effectively reduce the energy used by these data centers by one-half or more. This requires implementation of a variety of measures in a synergistic fashion, including the promotion of standards and metrics for data center equipment, and promotion of improved data center designs and operation schemes. Outreach and promotion from a credible source such as PG&E (who does not sell the equipment) is crucial. As PG&E only sells energy to these data centers, its efforts to promote a variety of products and services being offered by a variety of firms (including IBM, HP, Sun, Intel, VMWare, etc.) are providing critical credence to the claims of these various vendors as well as optimal integration of the services and products offered by them. PG&E also sponsored a data center design charrette in 2005 that helped develop ideas on how to improve energy efficiency in these facilities. Yet, how will the savings from these efforts be apportioned among the entities involved? Given that affordability is not a key issue for this market, whereas awareness and credibility are, how will free-ridership be measured? Given the quick uptake and high turnover of personnel typical of this marketplace, with the expectation that about half of it will have adopted for example virtualization (whereby they can get rid of about 70-80% of the servers and cooling needs of a data center by increasing the load from 10% to 70% in each server), will evaluations be able to gather reliable free ridership (or spillover) data before the market is basically transformed? Given the large savings being obtained with minimal public resources, this effort appears to be very cost-effective and something to try to emulate in other markets. Under current policies it is unclear what savings will be attributed to PG&E's efforts.

These three examples show issues around using NTG (especially based solely on free-ridership), and how focusing on attribution of savings is not only near impossible for these big and bold strategies, but worse, makes these very risky endeavors for PG&E to pursue.

California Needs New Evaluation Protocols for Energy Savings Attribution

Given the rapidly changing, increasingly embracing energy efficiency context we live in California, it is imperative to develop new evaluation methods, policies and protocols that will help guide and ensure optimal use of public energy efficiency resources. These new policies and protocols should foster leveraging much larger private resources with carefully crafted public interventions.

Current California protocols and CPUC rulings need to be updated to increase the focus on maximizing social benefits accruing from public resources, to balance these goals with the current one that focuses on attempting to attribute savings to specific public efforts; and take advantage of a societal context where there is a large opportunity for saving energy by leveraging market actors resources. There is an increasing level of activity from private market actors that is tapping into energy efficiency regardless of the presence of publicly funded, utility administered efforts. Customers are more interested in adopting energy efficiency than ever before as they try to do their part to solve a variety of issues they care about (Climate Change, USA's "addiction to oil", Iraq war, etc).

Utilities need to meet goals that are set at levels that are hard to achieve under current rules governing what counts or does not if they are to get shareholder incentives for their energy efficiency efforts. The CPUC requires evaluations to estimate NTG, but only considering free riders, with no credit for spillover savings. Given current market conditions, it is impossible to estimate a reliable free-rider-based NTG and/or spillover. Furthermore, the reticence to accept spillover leads to increased resources being assigned to programs where the savings not only are "counted" but also, "attributable" and help programs meet their large energy savings goals. Current policies lead implementers to avoid programs that may have large spillover effects; in essence spending the resources in less cost-effective efforts. And to add insult to injury, yesterday's spillover (that you never accounted) turns into today's baseline. In the long run this leads to underestimation of energy savings and cost-effectiveness.

The inordinate focus on attribution also takes away resources that could be used to better understand the markets we are trying to influence, thus detracting from the quality and depth of the information we use in designing and running publicly funded energy saving interventions. Evaluation activities are thus done in an institutional framework that determines the scope of the activities and analyses undertaken. The majority of energy efficiency programs are done with public monies overseen by a public entity. This institutional framework leads to evaluations that cater to the needs of ensuring public oversight, but not necessarily clearly identifying the needs of customers, or the programs that attempt to get customers to adopt energy efficiency. As these are the major evaluative efforts, they also affect the evaluation community framing the scope of enquiry and methods. In my view, the current framework may be giving us a distorted view-as it does not encompass other issues that may be crucial at really finding out what works, as efficiency markets evolve.

As the CPUC gets ready to define energy efficiency goals for 2009-2011, there is an increased awareness of the changing context, the increased difficulty for determining NTG, and the need to review the rules and evaluation protocols under which the IOUs administer the energy efficiency public endeavors.

Of late, there is a growing concern among evaluation practitioners about the capability of estimating accurately NTG and attribution of savings to specific programs given the current context, and/or using these to design program offerings (see recent conference proceedings of AESP 2007, IEPEC 2006, and Barnes 2007; Chappell et al. 2005; R Friedmann 2005, 2006; Saxonis 2007). Market effects indicators appear to be the preferred choice at this juncture (Chappell et al. 2005). Much more work is needed here to develop new indicators and then protocols aligned with them to foster the ongoing evolution of energy efficiency markets and energy savings by customers.

Conclusions

Paper has shown that the current context in California allows for new energy efficiency intervention strategies. Given the private market's interest in selling or adopting energy efficiency to increase profits and show good corporate citizenship and customer's increased interest to "do what's right", publicly funded efforts can change their "mainstream" efforts to interventions that optimize leveraging of private market actor efforts. Publicly funded efforts will still need to deal with creating new options for early adopters as well as addressing "laggard" customers via Codes and Standards. It is with the mainstream customer that publicly funded efforts can now let the relatively mature California energy efficiency market take a bigger role and even the lead, and intervene with public funds to "oil" this private markets' machinery.

Current evaluation policies and protocols make difficult such a change in public energy-efficiency interventions. They insist on calculating free-ridership and not allowing for savings from non-incented energy efficiency improvements. Changing current policies to allow for counting spillover from participants and non-participants needs to be addressed.

But both spillover and free-ridership are becoming much harder to determine as the context becomes one that embraces energy efficiency (for a variety of reasons that have little to do with saving energy). Therefore, new evaluation metrics, methods, policies and protocols need to be developed to better understand customer adoption decision-making, identification of key leverage points in the markets for energy efficient products and services, so that publicly funded interventions can continue to focus their efforts in the most cost-effective and socially beneficial manners.

References

H. Barnes. 2007. "Market-Effects Momentum: Are We Giving Market Effects Their Full Due?" *In Proceedings of the 2007 IEPEC,* Oregon, WI: International Energy Program Evaluation Conference. Forthcoming.

California Public Utility Commission. 2004. "Energy Saving Goals for Program Year 2006 and Beyond." Decision 04-09-060. San Francisco, Calif.: Public Utilities Commission of the State of California.

Chappell, C., D. Mahone, L. Megdal, and K. Keating. 2005. "White Paper on Methods for Estimating Net-to-Gross Ratio for Non-Residential New Construction." Southern California Edison.

Friedmann, R., and K. James. 2005. "Optimal Design, Implementation, and Evaluation of an Energy Eficiency Portfolio." *In Proceedings of the IEPEC 2005 Conference,* 911-919. Madison, WI.: International Energy Program Evaluation Conference.

Friedmann, R. 2006. "Time to Sweep the Dust From Under the Rug?" *In Proceedings of the 2006 ACEEE Summer Study.* 8:76-87. Washington D.C.: American Council for an Energy-Efficient Economy.

Goldstein, D. 2007. *Saving Energy, Saving Jobs.* San Francisco, CA.: Bay Tree Publishing.

Itron, Kema, RLW Analytics, and AEC. 2006. *California Energy Efficiency Potential Study.* Sam Francisco, CA.: Pacific Gas and Electric Company.

Prindle, B. M. Eldridge, M. Eckhardt, and A. Frederick. 2007. *The Twin Pillars of Sustainable Energy: Synergies Between Energy Efficiency and Renewable Energy Technology and Policy.* Washington D.C.: American Council for an Energy-Efficient Economy.

RLW Analytics. 2005. *California Statewide Residential Lighting and Appliance Efficiency Saturation Study.* San Diego, CA: San Diego Gas & Electric Company.

Rogers, Everett (1995). *Diffusion of Innovations.* New York: The Free Press.

W. Saxonis. 2007. "Free Ridership and Spillover: A Regulatory Dilemma." *In Proceedings of the 2007 IEPEC,* Oregon, WI: International Energy Program Evaluation Conference. Forthcoming.

TecMarket Works. 2004. *The California Evaluation Framework.* Prepared for Southern California Edison Company. Oregon, WI: TecMarket Works.

TecMarket Works. 2006. California Energy Efficiency Evaluation Protocols: *Technical, Methodological, and Reporting Requirements for Evaluation professionals*. Oregon, WI: TecMarket Works.

Attachment 241.1

REQUEST FOR PROPOSAL

Fairness Advisor – Natural Gas Vehicle Incentive Program

REFERENCE: P122058RDM

May 2012

FORTIS BC™

Table of Contents

Part 1

Instructions to Proponents

1. Invitation to Submit Proposal

FortisBC Energy Inc. (“FortisBC”) invites Proponents (“Proponents”) to submit a proposal (“Proposal”) for the Project described in Part 2 hereof (the “Project”) in accordance with the following instructions.

2. Identification of Proponents

Each Proposal shall include the Proponents’s:

a) Name and address
b) Telephone number
c) Facsimile number
d) E-mail address
e) Signature of authorized signatory
f) Name (printed) of authorized signatory
g) Title of authorized signatory

3. Proposal/Clarification

3.1 All Request for Proposal clarification shall be addressed in writing to the FortisBC point of contact stated in Section 7.2 at least three (3) business days prior to the closing time. All replies shall be confirmed in writing by FortisBC and any reply other than in writing is invalid. Any instructions or Proposals given to Proponents other than by the Procurement person are invalid.

3.2 A reply to all questions, if any, shall be made in the form of an addendum(s) which will be forwarded to all Proponents. Proponent must include the numbers of all Addendum(s) received in the space provided in Part 3 Proponent’s Proposal. It is the responsibility of the Proponent to ensure it has obtained and reviewed all addendum(s) prior to submission of its Proposal. All addendum(s) shall be incorporated into the Proposal and shall become part of the Contract Documents.

3.3 No verbal agreement or conversation made or had at any time with any officer, agent or employee of FortisBC, nor any oral representation by such officer, agent or employee, shall add to, detract from, affect or modify the terms of the Request for Proposal or be relied upon in any way whatsoever, unless specifically incorporated in a written addendum issued by FortisBC.

4. Knowledge of Work

Before submitting a Proposal, the Proponent shall obtain all necessary information, local or otherwise as to risks, contingencies and other circumstances which may influence or affect its Proposal.

5. Request for Proposal Schedule

Key Event	Date
Request for Proposal (RFP) Issued	Wednesday, May 23, 2012
Close of Proponent Questions	Friday, May 25, 2012 @ 12:00 Noon (PST)
Close of RFP	Wednesday, May 30, 2012 @ 12:00 Noon (PST)

6. Joint Information/Subcontractors

A Proponent may submit a Proposal wherein more than one company will be providing the Proposal, either through a joint Proposal or through a subcontracting arrangement.

The Proponent submitting the Proposal shall:

a) identify all companies party to the Proposal;

b) identify the solution components to be provided by each participant;

c) identify the primary Proposal's representative who shall assume all responsibilities for the Proposal and if successful the contracted services and materials; and

d) not add or substitute other companies without first obtaining written consent from FortisBC.

7. Knowledge of Work and FortisBC Contact Proposal

7.1 Before submitting its Proposal, Proponents shall obtain all necessary information, local or otherwise as to risks, contingencies and other circumstances which may influence or affect its Proposal.

7.2 All communications during the Request for Proposal period shall be made directly with:

Ray D. Munroe, SCMP
Sr. Procurement Specialist
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8

Phone: 604-592-7758
Facsimile: 778-571-3201
Email: ray.munroe@fortisbc.com

8. Basic Proposal

8.1 All Proposals must be submitted in the following structure:

a. Proponent's proposal that reflects the requirement in Part 2 Scope of work

b. Proponent's completion of Part 3 Proponent's Proposal

c. Proponent's completion of Appendix A

8.2 The Proponent may, in addition to the Proposal requested herein, submit alternatives to this Request for Proposal which meet or exceed the requirements set out. Any alternatives must be at least as specific in detail as the basic Proposal.

9. Delivery of Proposal

9.1 Delivery of the Proposal must be received no later than **12:00 Noon local Pacific Standard Time (PST)** on **Wednesday, May 30, 2012** (the "Closing Time"). If mailing, then please submit the Proposal to:

Ray D. Munroe, SCMP
Sr. Procurement Specialist
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C.
V4N 0E8

Reference: P122025RDM

9.2 Faxed/E-mail Proposal will be accepted prior to closing time. It is the sole responsibility of the Proponent to ensure that faxes/emails have been received by the FortisBC Procurement Department. Please ensure all emails have the RFP reference number and your company name in the subject line.

9.3 FortisBC reserves the right, in its sole and absolute discretion to extend the Closing Time, but is not obligated to do so.

9.4 Proposals which have not been received by FortisBC Procurement Department prior to Closing Time and are delivered after the Closing Time will not be accepted.

10. Proposal Preparation Costs

Costs associated with preparing Proposals to this Request for Proposal are the sole responsibility of the Proponents.

11. Acceptance and Rejection of Proposals

11.1 Proposals will be opened privately at the offices of FortisBC. Following submission of the Proposal and within forty-eight (48) hours of being requested, Proponents shall provide such additional information as called for herein and as may be required by FortisBC.

11.2 Without limiting the generality of the foregoing, FortisBC reserves the right, in its sole and absolute discretion, to accept or reject any Proposal which in the view of FortisBC, is incomplete, obscure, or irregular, which has erasures or corrections in the documents, which contains exceptions and variations, which omits one or more prices, which contains prices FortisBC considers unbalanced.

11.3 Criteria which may be used by FortisBC in evaluating Proposals and selecting the short-list of Proponents and the weight, if any, to be given to the criteria are in FortisBC's sole and absolute discretion and, without limiting the generality of the foregoing, may include one or more of, in no particular order:

a) pricing /total cost to FortisBC (include hourly rates and fee disbursements if applicable);

b) experience of conducting similar studies and/or assessments;

c) ability to meet business requirements of the Project;

d) work plan – proposed methodology, project schedule and project deliverables;

e) project team and/or experts;

f) Proponents financial capacity;

g) quality and completeness of the Proponent's Response; and

h) acceptance of the legal terms and conditions contained in Part 4.

11.4 Should FortisBC not receive any Proposal satisfactory to it in its sole and absolute discretion, FortisBC reserves the right to cancel the Request for Proposal or negotiate a contract for the whole or any part of the Work and with any one or more persons whatsoever, including but not limited to one or more of the Proponents.

11.5 Notwithstanding the Clauses above, FortisBC reserves the right, in its sole and absolute discretion, to include Proponents in the next stage of the process subject to internal Project review, obtaining Project approval and obtaining Project funding.

11.6 Notwithstanding any other provision of the Request for Proposal, it is a fundamental condition of this call for Proposal and the receipt and consideration of Proposals by FortisBC that FortisBC and its employees, contractors, consultants and agents will not and shall not under any circumstances whatsoever, including without limitation whether pursuant to contract, tort, statutory duty, law, equity or otherwise, and including but not limited to any actual or implied duty of fairness, be responsible or liable for any costs, expenses, claims, losses, damages or liabilities (collectively and individually "Claims") incurred or suffered by Proponents as a result of, arising out of, or related to any of the Request For Proposal, any Addenda, the preparation, negotiation, acceptance or rejection of any conforming or non-conforming Proposal, the rejection of any Proponents, the cancellation, suspension or termination of the tendering process, or the postponement, suspension or cancellation of the Work, and by submitting a Proposal each Proponents shall be conclusively deemed to waive and release FortisBC and its employees, contractors, consultants and agents from and against any and all such Claims. Proponents shall indemnify and hold harmless FortisBC and its employees, contractors, consultants and agents against any and all Claims brought by third parties against FortisBC or any of its employees, contractors, consultants and agents which arise out of or are related to any one or more of the preparation, submission and negotiation of any Proposal by the Proponents. Without limiting the generality of the foregoing, FortisBC shall not be under any obligation whatsoever to award the Work to the Proponents or anyone else and may cancel the Request for Proposal and reject any or all Proposals received at any time for whatsoever reasons FortisBC in its sole, absolute and unfettered discretion considers to be its best interest.

12. Request for Proposal Documents

The Request for Proposal documents consist of the Instructions to Proponents (Part 1), Scope of Work (Part 2), the Proponent's Proposal (Part 3), Statement of Proponent's Qualifications (Appendix "A"), and Terms and Conditions (Part 4).

13. Terms and Conditions

The Terms and Conditions are attached in Part 4 of this Request for Proposal.

14. Insurance

Prior to commencing the Work, the successful Proponent shall provide FortisBC with proof of the insurance required in Clause 13 of the Terms and conditions found in Part 4.

Part 2

Scope of Work

FAIRNESS ADVISOR – NATURAL GAS VEHICLE INCENTIVE PROGRAM

Background

The BC Government has recently issued a regulation under the Clean Energy Act that will authorize FortisBC to provide incentives to stimulate the adoption of natural gas vehicles in BC's transportation market (copy of regulation attached).The goal of the program is to initiate a market transformation from high-carbon fuels such as diesel fuel, to lower carbon natural gas in the heavy duty vehicle market segment. Participants in this program will benefit from incentive funding to offset part of the cost premium associated with NGVs relative to conventionally fuelled vehicles. By switching to natural gas, the transportation sector will realize the economic benefits of using natural gas as a heavy duty vehicle fuel and will achieve environmental benefits through the displacement of high-carbon fuels. The program is targeted for fleet vehicles in British Columbia in the following four market applications:

- heavy-duty trucks (e.g. Class 8 tractors);
- vocational vehicles (e.g. waste haulers, delivery vehicles);
- buses; and
- marine vessels (e.g. ferries)

The natural gas loads generated by the program will increase utilization of FortisBC's delivery system, which will reduce delivery rates paid by FortisBC customers. Hence existing customers will benefit from the program.

Benefits of Switching to Natural Gas

- GHG Emission Reductions – GHG emission reductions from NGV technology ranges from 20 – 30% relative to diesel fuel or gasoline with conventional natural gas. As FortisBC acquires additional biomethane supply resources it may be possible to further reduce fleet GHG emissions to be fully carbon neutral.
- Fuel Cost Savings – Net fuel cost savings to the fleet owner can range between 30 – 50% net of the cost of the vehicle fueling service.
- Demonstrated performance – NGVs have a proven track record in heavy duty applications. Please visit FortisBC's website for summaries of current commercial projects.

Business Objectives

FortisBC is seeking proposals regarding providing "fairness advisor" services on the execution of our Natural Gas Transportation Incentive Program for Heavy Duty and Return-to-Base Fleet Vehicles. Separate components of the Regulation further authorize FortisBC to make expenditures on CNG fueling stations and LNG fueling stations. However, reviewing fueling station expenditures does not form part of the Scope of Work for the services that are requested in this RFP. . The key elements of the program are described below.

The Incentive Program

The Regulation authorizes FortisBC to provide $62 million in incentives prior to March 31, 2017. It covers both compressed natural gas (CNG) and liquefied natural gas (LNG) fueled vehicles. Funds will be invested by FortisBC with costs proposed to be amortized in natural gas rates over a 10 year period. The costs associated with this program will be charged to all FortisBC customers. (Cost recovery in rates is subject to the approval of the BCUC).

- <u>Incentive Amount</u> - Under the program FortisBC will provide incentives to offset a percentage of the incremental capital cost of a qualifying new factory-built NGV or qualified conversion (e.g. ferries) over the cost of a comparably equipped diesel powered vehicle. In the funding allowance for 2012 FortisBC will provide funding of up to 80% of the incremental cost of the NGVs[1]. FortisBC will reduce the funding maximum by 10% per year in each subsequent year of the program as the adoption of natural gas in heavy duty transportation increases. The overall program will expire on March 31, 2017. The total authorized expenditure under the program is $62 million.

- <u>Program Eligibility</u> – The program is open to participation by any owner or lessor of heavy duty vehicles in British Columbia. Applications will be evaluated in an open and competitive process and measured against defined program criteria. FortisBC expects that the demand for funding will exceed available funding.

Evaluation criteria

Detailed evaluation criteria will be provided for the selected Fairness Advisor, however, a summary of these is found below:

- Firstly, the applicant must meet fundamental requirements for high-carbon fuel displacement, a satisfactory safety record, financial stability, and professional fleet operation and management capability.

- Secondly, the evaluation will measure the amount of high-carbon fuel displacement per unit of funding. Thus project proposals which displace larger quantities of fuel (relative to other vehicles within a vehicle category) may receive higher ratings.

- Finally, applicants will be selected based upon the diversity of the applications received in this round of funding. FortisBC seeks diversity by vehicle type and geographic location within British Columbia. Thus this stage of the evaluation will depend upon the mix of applications received by FortisBC in this round of funding as well as the fueling infrastructure plans provided by those applicants.

[1] The final percentage of the vehicle cost differential to be awarded is at the discretion of FortisBC Energy Inc.

Guiding Principles and Program Objectives

In evaluating applications, the Fairness Advisor will consider the following:

- High-carbon Fuel Displacement - Projects should result in the displacement of high-carbon fuel consumption. Applicants will be expected to provide credible estimates of conventional fuel consumption that will be displaced through the proposed project (on an annual basis and over the life of the vehicles). Evaluation criteria will measure the amount of high-carbon fuel displacement per unit of funding.

- Greenhouse Gas (GHG) Emission Reductions – Applicants will identify the level of GHG reductions that will be achieved through the implementation of the project (as validated by the GHGenius model[2], measured annually and over the life of vehicles) by providing their present diesel consumption and annual operating distances.

- Fueling Infrastructure and Operating Service – Applicants must provide a plan for providing fuel to the NGVs. Strong candidates are vehicles that return to the same location for fueling on a regular basis or vehicles which operate between defined destinations on regular routes or corridors. As a rough guideline, to be economically viable, CNG projects will need a minimum scale of approximately 150,000 litres of diesel displacement and LNG projects will need a minimum scale of 300,000 litres of diesel displacement. Alternatively, smaller projects can be proposed provided there is a plan to fuel the vehicles through an existing station or a station that is being proposed for another project. Consortium approaches, where vehicles from several fleets are fueled at a single location, may also be proposed.

- Provision of Fueling Services – CNG and LNG Fueling services (e.g. fueling stations) can be supplied by the applicant directly or through contracts with third party providers. While FortisBC is able to provide such services, there is no requirement to contract for fueling services through FortisBC and the selection of the fueling service provider will not influence awards made under this program in any way.

- CNG and LNG Projects – The program awards will seek to establish projects for both CNG and LNG service.

- Diversity of Applications – A desired outcome of the program will be the establishment of a wide variety of natural gas transportation applications in many local markets and sectors in B.C. Applicants that demonstrate the ability to lead market transformation within their industry segment will be viewed favorably under this element.

[2] Please refer to www.ghgenius.ca. This model was developed for Natural Resources Canada to analyze lifecycle emissions of traditional and alternative transportation fuels.

- Diversity of Geography – A desired outcome of the program is to establish strategic natural gas transportation corridors across the province so that economic benefits from the program are not unduly concentrated in any one region.

- Operating Commitment - Successful applicants will be required to commit to operate the vehicles in British Columbia for the life of the vehicles to ensure that future economic and environmental benefits from the program accrue back to FortisBC's natural gas rate payers.

Timeline

FortisBC plans to launch the program at the beginning of June (June 1st target date). Successful applicants will be notified by the end of August, 2012. Over 500 trucking companies and shippers will be invited to apply for funding by describing their proposed project and their capabilities to run a successful project.

- This will be an open and competitive call. A call for proposals will be done at least once a year for the next 5 years and we expect a strong response in each call.
- The Fairness Advisor appointment will commence immediately and will continue until the completion of the call for incentive proposals.
- Proposals will be evaluated by a team within FortisBC and a qualified short list along with rejected proposal will be forwarded to the Fairness Advisor for review and recommendation of final projects.
    a. Awards will be published on our Website
    b. Contribution agreements will be executed
    c. Monies will be disbursed 25% on execution of the agreement and 75% upon receipt of the vehicles into service

Role of Fairness Advisor

The role of the Fairness advisor shall include:

a) Advice to the FortisBC team on matters of fairness
b) Be available to answer queries related to fairness
c) Provide formal written reports at specific points during the Project competitive selection process described below.
d) Observe and/or monitor communications and responses undertaken during the Project competitive selection process
e) Observe and monitor collaborative discussions and meetings
f) Observe and monitor the FortisBC request for proposal evaluation process
g) Observe and monitor relevant meetings where proponent comparisons are made and the criteria, weighting and rating systems are applied.

Deliverables

FortisBC requires a report of findings. Submissions should include the following:

1. A review of a short list of qualified projects and rejected proposals selected by the FortisBC internal team and a recommendation of final projects that are consistent with the programs goals and that the decision criteria has been fairly applied. Current program document drafts are attached, a detailed list of criteria and weighting will be provided to the Fairness Advisor for evaluation.
2. Provide an annual report indicating an opinion regarding the overall fairness of the program or stage(s) of the program completed in the prior year and identifying any opportunities for improvement. The Fairness Advisor's reports will be available to the Ministry of Energy, the BCUC and potentially other stakeholders.

FortisBC anticipates that there will be approximately 30 applications under the first round, although there may be a larger response with the large number of invitations being sent out.

Budget

Please provide an hourly rate for staff that would be involved in the project.

The estimated timeline for budgetary / planning purposes can be found below:

1. **Fairness Advisor Training** - review of program materials, including background and intent of program – 1-2 days
2. **Fairness Opinion -** review and recommendation of qualified and rejected proposals **- 3-5 days**
3. **Annual report** - 3-5 days
4. **Miscellaneous –** meetings, inquiries, calls – 1-2 days

Appendix “A”

Statement of Proponent’s Qualifications

Statement of Proponent's Qualifications

A. PROPONENT'S REFERENCES

List below three operations (other than FortisBC Energy Inc.) you have recently completed or are now conducting, and a reference who can be contacted regarding your performance.

Name of Firm	Person to Contact	Phone No.
1. Firm: **Description of work done:**		
2. Firm: **Description of work done:**		
3. Firm: **Description of work done:**		

B. PROPONENT'S EXPERIENCE

Experience: Number of years' experience of the Proponent in the business of providing Fairness Advisor services: ________ years.

- Please provide a comprehensive breakdown of the project manager's and team members' relevant experience including the names, positions and the qualifications of the individuals ***actually*** performing the work.

Part 3

Proponent’s Proposal

1. **REFERENCE:** **P122058RDM**

PROJECT: **Fairness Advisor – Natural Gas Vehicle Incentive Program**

CLOSING TIME: **Wednesday, May 30th, 2012** at 12:00 Noon Pacific Standard Time (PST)

NAME OF: ______________________________

ADDRESS: ______________________________

____

PHONE: ____________________ FAX: ____________________

E-Mail: ____________________

HST NUMBER: ____________________

2. **PRICING REQUIREMENTS (HST extra)**

2.1 Prices:

A. PRICES:

	Hourly Rate	HST	Total
For the completion of the work described in Request for Proposal P122058RDM Part 2 Scope of Work			

B. SUBCONTRACTOR'S INFORMATION

Describe the portions of the Work which the Proponent proposes to sub-contract. Names of key personnel, duties and a brief statement of previous experience for each subcontractor shall be provided:

____________________ ____________________

____ ____
____ ____
____ ____
____ ____
____ ____
____ ____
____ ____
____ ____

2.2 Currency

All prices shall be quoted in Canadian dollars. Where applicable, prices shall contain all duties and excise taxes.

3. If applicable, the Proponent agrees that all work shall be performed in accordance with the Workers' Compensation Act of the Province of British Columbia; the Proponent's Workers' Compensation Board Registration number is ________________.

4. In the event that FortisBC issues any addendum, please acknowledge receipt below:

Addendum #	Date Received

5. This section MUST be completed for the Proponent's Proposal to be considered. Check the correct box and provide a detail if 5.2 is selected:

5.1 The Proponent agrees to provide the services outlined in Part 2, Scope of Work and confirms that it accepts in their entirety the Scope of Work and the Terms and Conditions attached hereto as Part 4 and agrees to be bound by them. ☐

OR

5.2 The Proponent agrees to provide the services outlined in Part 2, Scope of Work in accordance with the Terms and Conditions attached hereto in Part 4 and agrees to be bound by them with the following specific exceptions to the Scope of Work and/or Terms and Conditions: ☐

____

____

____

____

____

____

____

____

____

6. IF THE PROPONENT IS A COMPANY OR CORPORATION, PLEASE FILL OUT THIS SECTION:

In Witness Whereof the Proponent has executed this Proposal the ______day of ____________________, 2012.

____________________________	____________________________
Authorized Signatory	Witness Signatory
____________________________	____________________________
Print name	Print name
____________________________	____________________________
Title	Title

OR

IF THE PROPONENT IS A PARTNERSHIP OR SOLE PROPRIETORSHIP, PLEASE FILL OUT THIS SECTION:

In Witness Whereof the Proponent has executed this Proposal on the ______ day of ____________________, 2012.

______________________________	______________________________
Signature	Witness
______________________________	______________________________
Print name	Print Name
______________________________	______________________________
Title	Title

Part 4

Terms and Conditions

1. Purchase Order

1.1. FortisBC Energy Inc. ("FortisBC") has accepted a quotation ("Quotation") from the Contractor (described as the Vendor in the Purchase Order) to provide services, the details of which are outlined in the Scope of Work attached to the Purchase Order.

1.2. The Terms and Conditions, the Quotation and the Scope of Work are all attached to the Purchase Order and collectively form the Contract Documents.

2. Scope of Work

Generally the services to be performed by the Contractor are set out in the Scope of Work attached to the Purchase Order (the "Work"). Specific services may be assigned by FortisBC throughout the term.

3. Representatives

3.1. Following the award of the Work to the Contractor, each party shall notify the other of its named representative. The Contractor's representative shall be available on the site where the Work is being performed.

3.2. FortisBC's representative shall be identified on the Purchase Order.

3.3. Any written notices required to be given to a party under the Purchase Order shall be delivered to the party's representative.

3.4. The parties' respective representatives shall have the authority to transmit information and instructions to one another and to act on behalf of and bind their respective parties.

4. Term of Purchase Order

This Purchase Order shall commence on the date set out on the Purchase Order (the "Commencement Date") and shall be deemed terminated and the Contractor discharged from any further obligation to perform services on the earlier of the date when the Work has been performed, accepted and approved by FortisBC (the "Termination Date") and the termination date identified on the Purchase Order (the "Scheduled Completion Date").

5. Progress of Work

5.1. The Contractor shall provide all services, labour, supervision and equipment necessary to perform the Work in accordance with the terms of the Purchase Order and the Scope of Work. The Contractor shall perform the Work in accordance with any drawings and instructions issued by FortisBC.

5.2. At the request of the FortisBC representative, the Contractor shall provide details about its plans and methods of performing the Work. If the FortisBC representative determines that the Contractor cannot supply personnel and equipment to meet the requirements of the Work as assigned on the schedule identified, the Contractor shall, if requested by FortisBC, expedite the progress of the Work at no additional cost to FortisBC.

6. Delay

6.1. If the Work as assigned is delayed beyond the specific Work assignments scheduled completion date(s), (the "Completion Date(s)") as a result of an event or circumstance which the Contractor could not have anticipated or avoided and which makes it impossible to perform the Work on time, the parties' representatives shall agree on, and failing such agreement, the FortisBC representative shall establish, an equitable adjustment of the time within which the Work is to be performed.

6.2. If the Work as assigned is delayed beyond the scheduled Completion Date(s) as a result of any act or failure to act by the Contractor, its agents, employees or subcontractors, the FortisBC representative shall either:

(a) establish an equitable adjustment of the amount to be paid for the Work or the time within which the Work is to be performed; or

(b) terminate the Purchase Order without incurring damages or penalties in accordance with Sections 12.1 and 12.2.

6.3. Any party anticipating a delay shall notify the other party as soon as possible with full particulars. Both parties shall make every reasonable effort to mitigate or overcome the effects of any anticipated delay.

7. Extra Work

7.1. The FortisBC representative may require the Contractor to perform work that is in addition to the Scope of Work and results in an increase to the cost of the Work ("Extra Work").

7.2. Prior to the commencement of any Extra Work, the details of the Extra Work shall be discussed and mutually agreed upon in writing by the parties. Failing agreement, the FortisBC representative may direct the Contractor, in writing, to proceed with such Extra Work which is within the general scope of the type of Work required by the Contractor or required to properly complete the Work, in which case the Contractor shall perform such Extra Work. Any dispute as to the Extra Work shall be resolved in accordance with Section 18 below.

7.3. Extra Work shall be paid at the hourly rate outlined in the Purchase Order, or if none has been set out, then at a rate to be mutually agreed upon prior to commencing the Extra Work. Failing agreement as to cost the parties will resolve the matter in accordance with Section 18.

7.4. FortisBC shall not accept any claim made by the Contractor for Extra Work unless the Contractor has complied with Sections 7.2 and 7.3 above.

8. Work Changes

8.1. The FortisBC representative may require the Contractor to perform any additions to or revisions of the Work which are within the scope of the Purchase Order and/or to make any deletions to the Work ("Work Changes").

8.2. If the FortisBC representative requires such Work changes, the parties' representatives shall agree on any equitable adjustment of the amount to be paid for the Work Changes and the time within which the Work Changes and the Work are to be performed, and, failing such agreement, either representative may escalate the disagreement within its organization and failing resolution may elect to have the matter resolved in accordance with Section 18. The parties will continue to fulfill their respective obligations pursuant to this Purchase Order during any resolution of any dispute.

9. Terms of Payment

9.1. Subject to any equitable adjustment or Section 18, FortisBC shall pay the Contractor an amount approved by the FortisBC representative as set out in the Purchase Order for performance of the Work in accordance with these Terms and Conditions.

9.2. The Contractor shall submit an itemized invoice, on the last day of each Month during the term of this Purchase Order unless otherwise specified in the Purchase Order, to the FortisBC representative, which at a minimum shall include:

(a) unit prices or lump sum prices, where appropriate, as set out in the Purchase Order, supported by the Contractor's time sheets;

(b) any Extra Work at the hourly rates as set out in the Contractor's Quotation or as mutually agreed upon between the parties; and

(c) applicable Harmonized Sales Tax ("HST").

9.3. The FortisBC representative shall verify the invoice and approve it for payment. Payment of the approved invoices shall be made by FortisBC to the Contractor within 30 days of receipt by FortisBC unless otherwise specified in the Purchase Order.

9.4. The Contractor shall remit the HST to the Canada Revenue Agency in accordance with all laws and regulations.

9.5. FortisBC will not, under any circumstance, be responsible for any tax monies not remitted in accordance with Clause 9.4 above, nor for any interest or penalties imposed on unremitted taxes.

9.6. FortisBC shall pay to the Contractor the applicable HST provided that the invoices that the Contractor provides to FortisBC include the following:

(a) sufficient information to identify the Contractor's name or trade name;

(b) the Contractor's HST registration number;

(c) sufficient information to identify the reporting period when the HST, in respect of the goods and services being provided by the Contractor, was paid or become payable and the amount of HST paid or payable;

(d) sufficient information to identify the name of FortisBC; and

(e) sufficient information to specifically identify the nature of the goods and services being provided and invoiced.

9.7. FortisBC shall not be responsible for any HST other than as specified above. The Contractor agrees to hold FortisBC harmless from and against any order, penalty, interest or tax that may be exercised or levied against FortisBC as a result of the failure or delay of the Contractor to file any return or information required by any law, ordinance or regulation. Without limiting the generality of the foregoing, FortisBC shall have no liability or responsibility for the payment of any penalty or interest assessed or levied against the Contractor as a result of the failure of the Contractor to charge, collect or remit the HST as required under all applicable laws.

10. Equipment & Materials of FortisBC

All maps, drawing, photographs, equipment and materials provided by FortisBC to the Contractor shall remain the property of FortisBC and the Contractor shall be responsible for the safe care, handling, custody and proper maintenance of them. The Contractor shall return any FortisBC property to FortisBC within ten (10) days of the termination of the Purchase Order.

11. Maintenance of Records

The Contractor shall keep full and detailed records respecting the Work performed for at least one year after completion of the Work and the Contractor shall permit FortisBC to inspect and audit these records at all reasonable times.

12. Termination

12.1. If the Contractor breaches a material term of the Terms and Conditions of this Purchase Order or is in substantial breach of the Terms and Conditions of this Purchase Order, becomes insolvent, commits an act of bankruptcy, has a receiver or liquidator appointed for its assets or otherwise files for protection from claims of its creditors, such that any of the above causes the Contractor to be unable to fulfil its obligations under this Purchase Order, assigns or abandons the Work, or fails to meet the Completion Dates, FortisBC may, without prejudice to any other rights or remedies it has, terminate this Purchase Order by giving the Contractor seven (7) calendar days written notice.

12.2. Notwithstanding the forgoing, in its sole discretion FortisBC reserves the right to cancel this Purchase Order without damages or penalty whatsoever by giving the Contractor fourteen (14) calendar days written notice.

12.3. Should FortisBC terminate this Purchase Order in accordance with Section 12.1 or 12.2, it shall only be required to pay the Contractor for Work completed to FortisBC’s satisfaction up to the date of Termination and those costs incurred solely for the purpose of completing that Work.

12.4. If FortisBC terminates the Purchase Order, it may take possession of the Contractor’s work product and materials and complete the Work. The Work, including, without limitation, finished drawings, materials, correspondence, calculations and other work in progress completed up the date of termination shall become the property of FortisBC.

12.5. If FortisBC fails to make payment to the Contractor when due under the Purchase Order, other than in cases where FortisBC disputes the amount of entitlements of the Contractor to some or all of a payment, breaches a fundamental term of the Purchase Order or is in substantial breach of the terms hereof, the Contractor may, without prejudice to any other rights or remedies it has, terminate this Purchase Order by giving FortisBC seven (7) calendar days written notice.

13. Insurance

13.1. Within five (5) days of award of the Work, the Contractor shall obtain at its own expense, the following insurance and with the exception of (a) below, name FortisBC as an additional insured and provide FortisBC with proof of the insurance coverage including:

(a) Automobile liability on all vehicles used by the Contractor in connection with this Purchase Order in the minimum amount of $2 million per occurrence in respect of bodily injury, death and property damage.

(b) General Commercial liability for bodily injury, death and property damage with minimum amount of $2 million per occurrence with respect to the Work. The policy shall also contain a cross liability provision.

13.2. During the term of this Purchase Order, FortisBC's representative may, by written notice, require the Contractor to obtain additional insurance or to alter or amend the insurance policies required under this Section at FortisBC's expense. The Contractor shall be responsible for the full amount of all deductible of all insurance policies required under this Section. All insurance policies required herein shall provide that the insurance shall not be cancelled or changed in any way without the insurer giving at least ten (10) calendar days written notice to FortisBC and shall be purchased from insurers registered in and licensed to underwrite insurance in British Columbia. Where the Contractor fails to comply with the requirements of this Section, FortisBC may take all necessary steps to affect and maintain the required insurance coverage at the Contractor's expense.

13.3. If an insurer fails or refuses to pay any claims under an insurance policy covering activities relating to or arising out of the Work, the Contractor will not be released from any responsibility and liability arising under these Terms and Conditions.

14. Worker’s Compensation Insurance

14.1. Within five (5) days of award, the Contractor shall provide FortisBC with written proof of Workers’ Compensation insurance coverage in accordance with the statutory requirements in British Columbia for all its employees engaged in performing the Work herein.

14.2. The Contractor shall comply with the British Columbia Workers’ Compensation Act and regulations thereto and shall pay all assessments, compensation and all other amounts required to be paid thereunder.

14.3. If the Contractor fails to pay any such assessment, compensation or other amounts when due, FortisBC may make such payment on behalf of the Contractor but will not be obliged to do so.

14.4. The Contractor shall reimburse FortisBC the amount of such payment upon demand, or FortisBC may deduct the amount from any payment then or thereafter due to the Contractor under the Purchase Order.

15. Indemnification

15.1. The Contractor shall indemnify and hold FortisBC, its directors, officers, agents and employees harmless from and against any actions, claims, damages, costs and expenses including without limitation all applicable solicitors' fees and disbursements, investigation expenses, adjusters' fees and disbursements whatsoever which may be brought against or suffered by FortisBC, or its directors, officers, agents and employees or which they may incur, sustain or pay arising out of or in connection with:

(a) any injury to or the death of any and all persons;

(b) damages, destruction or loss to or of any and all property whether real or personal; and

(c) any act, omission, default or representation, negligent or otherwise, of the Contractor, its employees, agents and subcontractors,

in any way incidental to the Work or this Purchase Order.

15.2. The Contractor shall defend any such claims or suits provided that FortisBC shall have the right at its option to participate in the defence of such claims or suits and in such events the Contractor shall pay FortisBC's cost for defending such claims or suits.

15.3. This indemnity shall survive the termination of this Purchase Order.

16. Safety & Security

The Contractor shall be responsible for the protection and security of the Work and the protection and safety of all persons performing the Work on the site. The Contractor shall comply with all safety procedures required by FortisBC.

17. Representations and Warranties

17.1. The Contractor hereby covenants, represents and warrants to FortisBC, and shall be deemed to have covenanted, represented and warranted to FortisBC on and as of the Commencement Date, as follows:

(a) the personnel the Contractor assigns to perform the Work herein possess the necessary qualifications, knowledge, skills, expertise and experience to perform the Work to the highest professional standards;

(b) the Contractor shall, at all times during the term of the Purchase Order, act in the best interest of FortisBC and shall perform the Work in a competent, workmanlike and professional manner and using due care and diligence;

(c) in performing the Work, the Contractor shall comply with all applicable laws, orders, regulations, ordinances standard, codes and other rules, licences and permits of all lawful authorities;

(d) the Contractor shall be responsible at no cost to FortisBC, to provide such additional services as may be necessary to remedy any deficiencies in the Work caused by the negligent act or omission of the Contractor or its employees, agents or subcontractors or by the failure of such party(ies) to perform the Work in accordance with the provisions of this Purchase Order; and

(e) where applicable, the Contractor shall take all measures in the performance of the Work to minimize disturbance or damage to the environment.

17.2. These representations and warranties shall survive the termination of the Purchase Order.

18. Disputes

18.1. Where any dispute arises out of or in connection with this Purchase Order, including failure of the parties to reach agreement hereunder, the parties agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution.

18.2. If the parties fail to resolve the dispute through mediation, the unresolved dispute shall be referred to, and finally resolved or determined by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution. Unless the parties agree otherwise the arbitration will be conducted by a single arbitrator.

18.3. The arbitrator shall issue a written award that sets forth the essential findings and conclusions on which the award is based. The arbitrator will allow discovery as required by law in arbitration proceedings.

18.4. If the arbitrator fails to render a decision within thirty (30) days following the final hearing of the arbitration, any party to the arbitration may terminate the appointment of the arbitrator and a new arbitrator shall be appointed in accordance with these provisions. If the parties are unable to agree on an arbitrator or if the appointment of an arbitrator is terminated in the manner provided for above, then any party to this Purchase Order shall be entitled to apply to a judge of the British Columbia Supreme Court to appoint an arbitrator and the arbitrator so appointed shall proceed to determine the matter mutatis mutandis in accordance with the provisions of this Section.

18.5. The arbitrator shall have the authority to award:

(a) money damages;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

18.6. The costs and expenses of the arbitration, but not those incurred by the parties, shall be shared equally, unless the arbitrator determines that a specific party prevailed. In such a case, the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party.

18.7. The parties will continue to fulfill their respective obligations pursuant to this Purchase Order during the resolution of any dispute in accordance with this Section 18.

19. Subcontracting

19.1. No subcontracting of any of the Work shall be permitted without the prior written consent of FortisBC which consent may be arbitrarily withheld.

19.2. Notwithstanding FortisBC's consent to the subcontracting of any of the Work, no subcontracting of any Work shall relieve the Contractor from its obligations and responsibilities to FortisBC pursuant to this Purchase Order. Nothing contained in these Terms and Conditions shall be construed as creating any contractual relationship between FortisBC and a subcontractor.

20. Relationship

In performing the Work, the Contractor shall be an independent contractor and as such shall not have authority to bind or commit FortisBC and shall have responsibility for the control over the details and means of performing the Work. The Work shall be performed by the Contractor under its own superintendence and at its own risk. Nothing herein shall be deemed or construed to create a joint venture, partnership, employment or agency relationship between the parties for any purpose.

21. Assignment

The Contractor shall not assign its rights or obligations under this Purchase Order without the prior written consent of FortisBC, which consent may be arbitrarily withheld. FortisBC may assign this Purchase Order without the consent of the Contractor.

22. Confidentiality

22.1. All information or documentation received by a party (the "Receiving Party") pertaining to or arising from the Work or the business affairs or trade secrets of the other party (the "Disclosing Party") shall be deemed to be confidential and proprietary to the Disclosing Party. Except as otherwise provided herein, the Receiving Party shall not directly or indirectly disclose any such confidential information or documentation to any third party without the prior written consent of the Disclosing Party. Such consent is not required where the third party is another contractor or consultant retained by the Disclosing Party for the purposes of the Work and to the extent that such disclosure is necessary for the proper performance of this Purchase Order.

22.2. Notwithstanding the foregoing, the Receiving Party may use such confidential information or documentation pertaining to or arising from the Work in the preparation for and conduct of submissions to regulatory agencies.

22.3. The obligation of confidentiality set out above shall not apply to material, data or information which is known to either party prior to its receipt thereof, which is generally available to the public or which has been obtained from a third party which has the right to disclose the same. The confidentiality covenants of the parties herein shall survive the termination of this Purchase Order.

22.4. The Contractor further acknowledges and agrees that FortisBC has, and shall have title to all information and documentation arising from the performance of the Work including, without limitation, reports, finished drawings, rough drawings, correspondence, notes, calculations computer programs, operating manuals, functional specifications, and related documentation and other work in progress and the Contractor shall surrender any of such material which may be in its possession to FortisBC at any time upon the request of FortisBC or at the expiry or earlier termination of the Purchase Order. In addition to the foregoing, upon completion of the Work, the Contractor agrees to waive all moral rights in any copyrighted works associated with the Work.

23. Personal Information and Protection of Privacy

23.1. The Contractor recognizes that during the course of this Purchase Order FortisBC may provide the Contractor with "personal information" and or "employee personal information" as those terms are defined in the British Columbia *Personal Information Protection Act* (collectively "Personal Information"), and that disclosure by FortisBC to the Contractor of this Personal Information places certain obligations on the Contractor relating to the retention, use and disclosure of that Personal Information by the Contractor.

23.2. The Contractor shall only retain, use or disclose Personal Information for the limited purpose for which FortisBC disclosed the Personal Information to the Contractor so as to allow the Contractor to perform the Scope of Work under the Contract Documents. Any further use or disclosure is strictly prohibited without FortisBC's express consent.

23.3. In the event that the Contractor proposes to disclose the Personal Information to third parties or subcontractors ("Third Parties") in connection with the performance of the Scope of Work under the Contract Documents, the Contractor will seek the consent of FortisBC prior to such disclosure and will not proceed with such disclosure until the consent has been obtained. In such cases, the Contractor will also ensure that the Third Parties deal with and treat the Personal Information in the same manner as the Contractor is required to do under these Terms and Conditions.

23.4. In dealing with Personal Information provided to the Contractor by FortisBC or its agents, the Contractor shall ensure that the Personal Information is handled in a manner that complies with FortisBC's Privacy Policy.

23.5. If FortisBC receives a complaint that the Contractor has not dealt with Personal Information in a manner permitted under these Terms and Conditions or if FortisBC has reasonable grounds to believe that the Contractor has used or disclosed Personal Information in a manner not permitted under these Terms and Conditions, then FortisBC may at reasonable times inspect the Contractor's records as set out in Clause 11 to assess the validity of the complaint, or to ensure compliance with the privacy requirements of this Contract.

23.6. FortisBC may, in its sole and absolute discretion, require the Contractor to return all records, in any medium, that contain Personal Information disclosed to the Contractor by FortisBC. Where the return of such records is impractical, FortisBC may require the Contractor to destroy and/or delete from its records any Personal Information disclosed from FortisBC to the Contractor. The Contractor shall have thirty (30) days from receipt of a written request from FortisBC to return or delete/destroy the records, to either return the records or to delete and/or destroy the Personal Information from them. FortisBC shall only make a request under this clause in circumstances where it is reasonable to do so, or where FortisBC is required to do so under the British Columbia *Personal Information Protection Act*.

23.7. Notwithstanding Section 23.6 above, the Contractor shall delete and/or destroy all Personal Information provided to it by FortisBC from the Contractor's records within one year following the completion of the Work. The requirement to expunge Personal Information within one year following the completion of the Work does not diminish in any other respect from the record keeping requirements set out in Clause 11 of this Contract or as required by law.

24. Agency

Where FortisBC requests the Contractor to carry out Work on Vancouver Island or the Sunshine Coast, FortisBC is acting as agent for FortisBC Energy (Vancouver Island) Inc. and all references in the Purchase Order to FortisBC shall be deemed to be references to FortisBC Energy (Vancouver Island) Inc. Where FortisBC requests the Contractor to carry out Work in Whistler, FortisBC is acting as agent for FortisBC Energy (Whistler) Inc. and all references in the Purchase Order to FortisBC shall be deemed to be references to FortisBC Energy (Whistler) Inc.

25. Law

This Purchase Order shall be governed by and construed in accordance with the laws of the Province of British Columbia.

26. Time

Time is of the essence in this Purchase Order.

27. Enurement

This Purchase Order shall be for the benefit of and be binding upon FortisBC and the Contractor and their respective successors and permitted assigns.

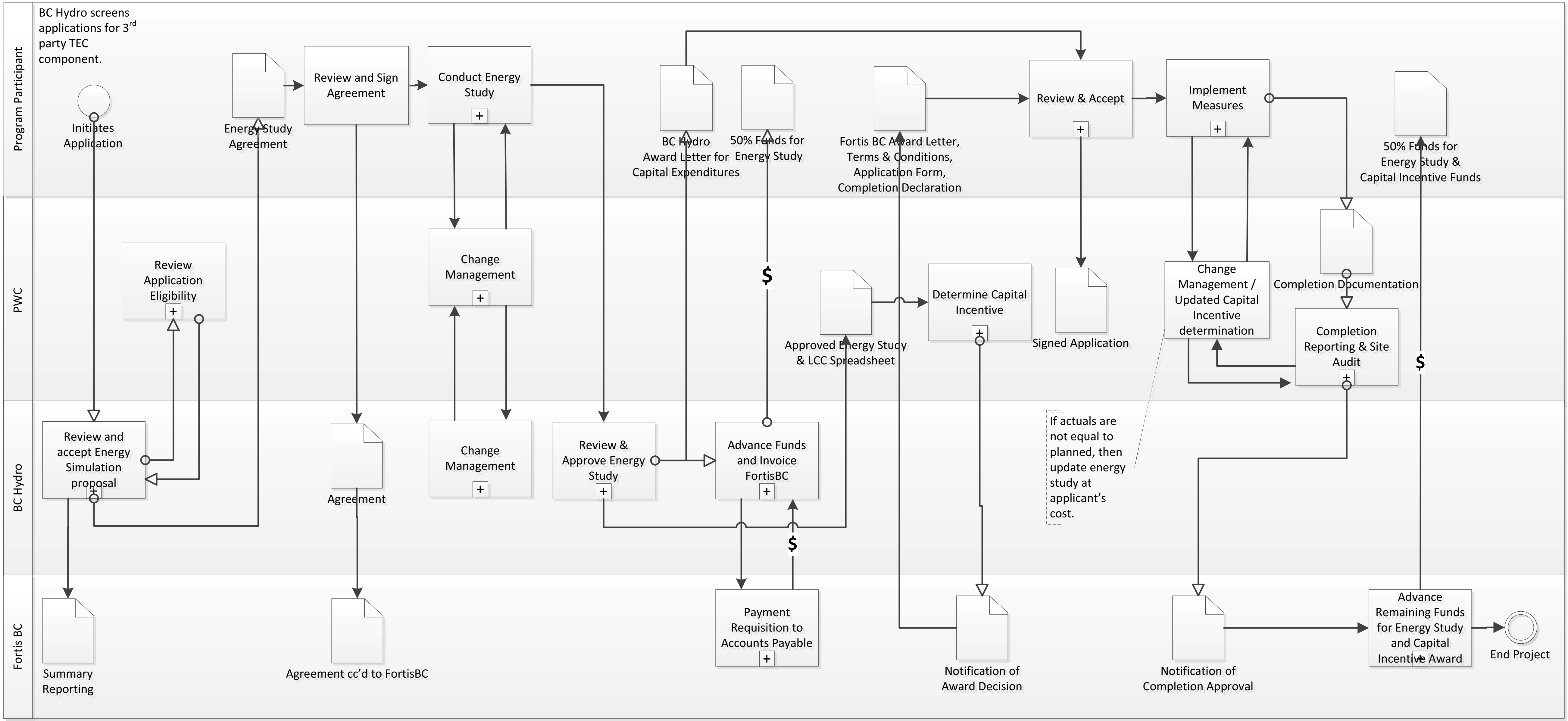
28. Amendments

Subject to any equitable adjustment made, the parties are not bound by any amendment, variation or waiver of any provision of this Purchase Order unless it is in writing and signed by their representatives.

Attachment 241.4

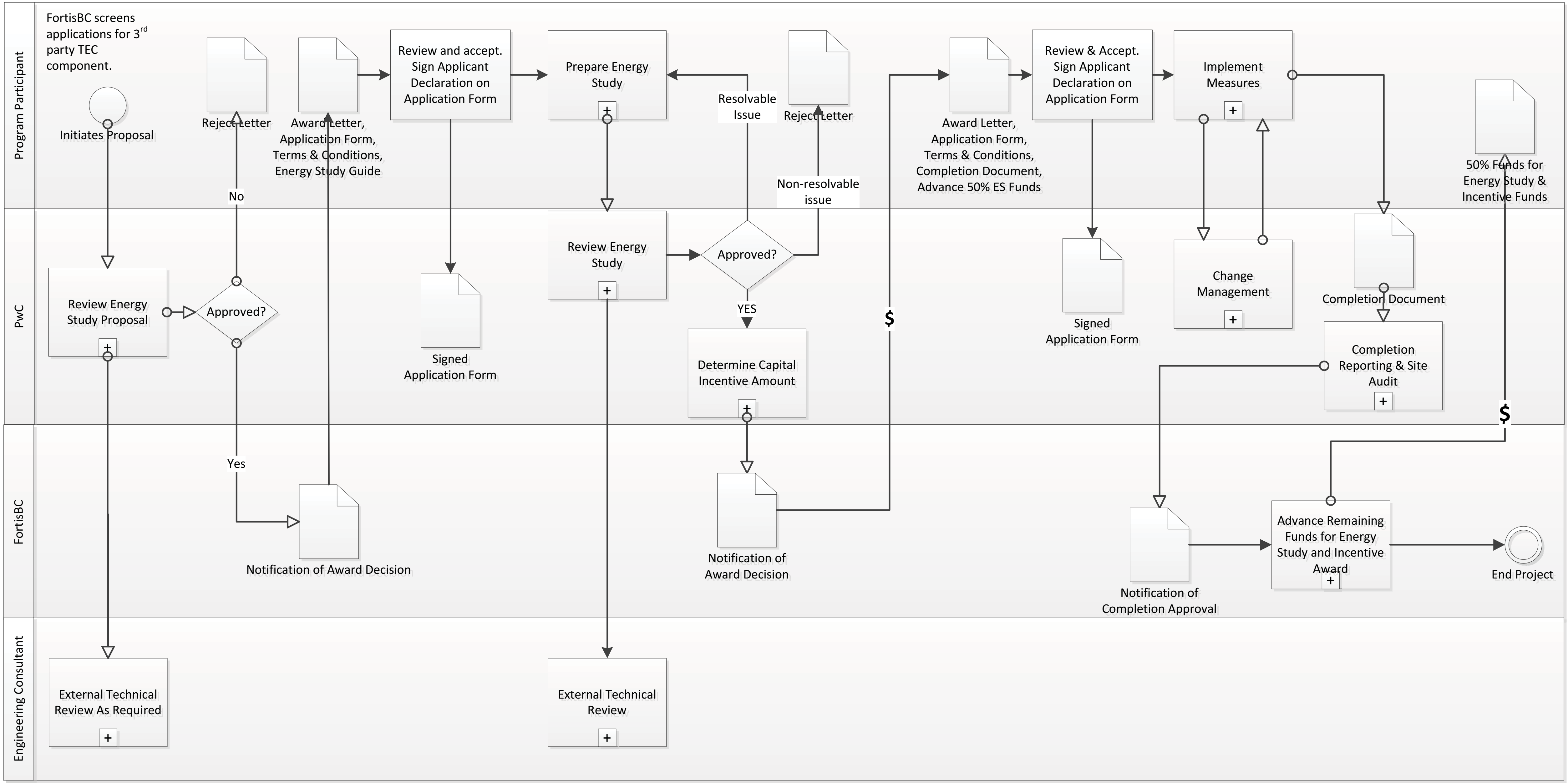
Custom Design Program – New Construction with 3rd Party TES Component

Estimated Annual Participation: 2 – 5
Estimated Annual LOE: 13-33 days



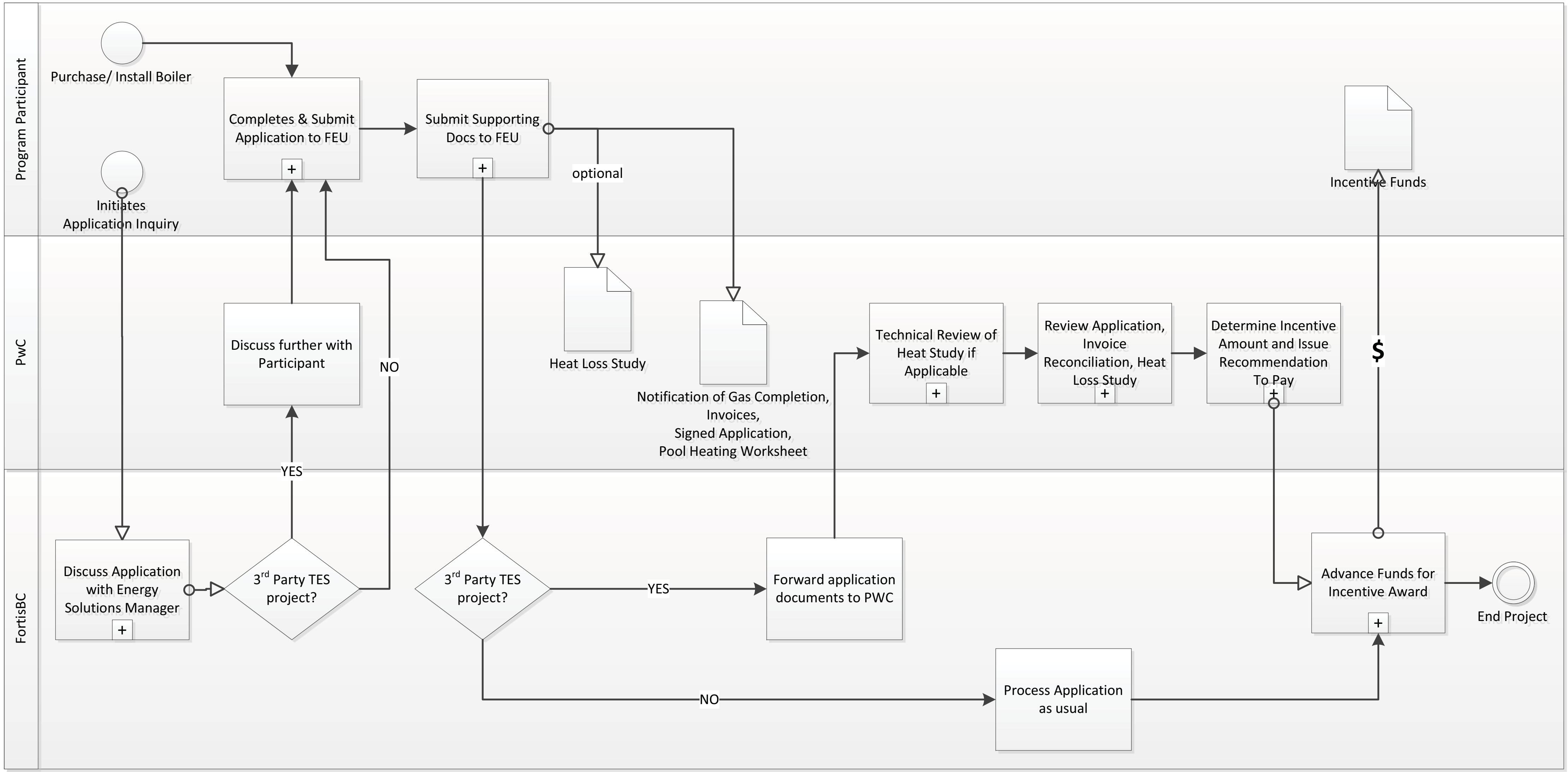
Custom Design Program – Retrofit with 3rd Party TES Component

Estimated Annual Participation: 5 - 8
Estimated Annual LOE: 60 – 96 days



Efficient Boiler Program

Estimated Annual Participation: 1 - 10
Estimated Annual LOE: 1 – 6 days



Residential New Homes Program

Estimated Annual Participation: 10 - 20
Estimated Annual LOE: 5 – 10 days